Q-400. Regarding implemented programs that contribute to operational efficiencies in distribution, as discussed beginning on page 43 of the Testimony of Paul W. Thompson, provide the following:

a. Written procedures, procedures and directives detailing all programs related to incident management.

   i. Explain how real-time information gained from SCADA DMS and AMS will be incorporated into each of these programs.

b. Written procedures, procedures and directives detailing all programs related to system/asset management.

   i. Explain how real-time information gained from SCADA DMS and AMS will be incorporated into each of these programs.

c. Written procedures, procedures and directives detailing all programs related to resource management.

   i. Explain how real-time information gained from SCADA DMS and AMS will be incorporated into each of these programs.

A-400.

a. See attached.

   i. Real-time information gathered from the SCADA, DMS, and AMS systems will be utilized to assess the condition of the LG&E electric distribution system before, during, and after an event. These systems will provide more accurate fault location predictions and provide automated and remote operations of field devices. Damage assessment will improve as it will be based on readily available real-time system data and status from field devices. This improvement will assist in determining restoration resource requirements and allow efficient utilization of those resources acquired to restore and repair the damaged areas.
b. See attached.

   i. AMS and SCADA enabled reclosers provide valuable enhancements to support asset management. Currently there is limited data available on the performance of the distribution system beyond the substation. AMS meters and SCADA enabled reclosers will provide data to allow the Company to proactively and in real time identify overloaded or malfunctioning equipment (transformers, lines, other line equipment, etc), power quality issues and other problems, such as tree contacts before they result in an outage and/or equipment failure or damage. More accurate load data outside the substation will allow lines to be configured for improved efficiency. Enhanced data improves system planning and operation and provides critical data to maximize investment in distribution assets for resiliency, reliability and capacity. SCADA enabled reclosers provide fault isolation and/or automatic service restoration to restore service to unaffected customer while reducing crew time to fault locate. AMS metering provide information on the extent of outages speeding restoration efforts and reduces truck rolls to verify service has been restored.

c. The Asset and Resource Management (ARM) software tool is utilized by Electric Distribution Operations to initiate, design, and approve planned construction and maintenance work. Jobs are assigned to field supervision to ensure work is completed as designed and on-time. A separate Work Planning organization monitors jobs in ARM and assigns a variable workforce to operation centers based on data housed in this system. ARM is not utilized for outage and restoration work so real-time data from SCADA, DMS and AMS would have limited impact on ARM tool processes and efficiencies. However, the real time data could be utilized to identify planned construction work such as identifying areas with loading or voltage issues. This information could also be used to identify failing or overloaded equipment that could be repaired or replaced on proactive planned maintenance in ARM.
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Appendix 10. EPRP Contact Lists
1. Introduction

**Purpose**
The purpose of the Electric Distribution Emergency Preparedness and Response Plan (EPRP) is to establish the Company’s organizational structure, associated roles and responsibilities, and high level processes to be utilized in response to emergencies and significant outage events on the Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU) electric distribution systems. The procedures outlined herein shall serve as guidelines to assist the Company during restoration events and are not intended to be a detailed training tool.

The purpose of EPRP Section 1.0 is to provide personnel with an overview of the scope of the EPRP and to establish the Company’s:
- Emergency Preparedness and Response Alert Levels, and the responsibilities associated with each level;
- Terminology for categorizing the scale or magnitude of emergency events, and the associated implications on associated restoration business processes and organizational structure; and
- Establish the personnel primarily responsible for execution and maintenance of this Plan and associated business processes.

**Scope**
The EPRP applies to all significant power outages caused by, but not limited to, severe weather, flooding, civil disturbances, fire or explosion or other major disruption of the Electric System or any instances for which the Vice President Electric Distribution or Operating Company management personnel determines the implementation of the EPRP, and the Incident Command System is required to affect safe and timely restoration of electric service.

The EPRP scope includes the Company’s electric distribution service territory, and associated electric infrastructure and customers. The electric distribution service territory is divided into eleven primary Operations Centers (see Figure 1):

A. Danville Operations Center
   a. Danville Operations Center
   b. Campbellsville Crew Center
B. Earlington Operations Center
   a. Earlington Operations Center
   b. Barlow Crew Center
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- c. Eddyville Crew Center
- d. Greenville Crew Center
- e. Morganfield Crew Center

C. Elizabethtown Operations Center

D. Lexington Operations Center
   - a. Lexington Operations Center
   - b. Midway Crew Center

E. London Operations Center -
   - a. London Operations Center
   - b. Somerset Crew Center

F. Louisville Operations Center
   - a. Auburndale Service Center
   - b. East Service Center

G. Maysville Operations Center
   - a. Maysville Operations Center
   - b. Mount Sterling Crew Center
   - c. Paris Crew Center

H. Norton Operations Center
   - a. Norton Operations Center
   - b. Pennington Gap Crew Center

I. Pineville Operations Center
   - a. Pineville Operations Center
   - b. Harlan Crew Center

J. Richmond Operations Center
   - a. Richmond Operations Center
   - b. Winchester Crew Center

K. Shelbyville Operations Center
   - a. Shelbyville Operations Center
   - b. Carrolton Crew Center
Plan Development and Review
The Emergency Preparedness, Planning, and Response Team (EPPRT), as described in EPRP 1.3, shall be responsible for developing the EPRP and conducting routine reviews of the plan to assure its continued accuracy and adequacy, in accordance with the EPRP Review and Approval Schedule established in Appendix 1.B.

Training and Qualification
The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. Please see the EPRP Plan Review, Training, and Exercise Schedule in Appendix 1.C.

References
None

Revisions
None
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1.1. Emergency Preparedness and Response Alert Levels

The Company shall utilize an Emergency Preparedness and Response Alert Level System which categorizes, defines, and triggers specific tasks to be completed during normal and abnormal operating conditions to assure the Company is prepared to effectively and efficiently respond to emergencies and outage events on its electric distribution system.

1.1.1. Blue Alert – defines the planning and preparedness tasks to be completed during normal (“blue sky”) operating conditions to ensure the Company is prepared to effectively respond to future emergencies and outage events on the electric distribution system.

1.1.2. Yellow Alert – defines the action items and preparedness tasks to be completed in advance of forecasted or impending events which could significantly impact the Company’s electric distribution systems, to ensure the Company is adequately prepared to effectively and efficiently respond to associated emergencies and outage events.

A Yellow Alert will be issued 0-72 hours in advance of the following forecasts by the National Weather Service for LG&E or KU service areas:

1. Severe weather forecast
2. Extreme temperature forecast
   a. 5°F or lower
   b. 90°F or higher
3. Forecast for sustained wind speeds or wind gusts greater than 40 miles per hour
4. Forecast for ice accretion totals equal to or greater than 0.25 inches
5. Prediction for flooding

1.1.3. Red Alert – defines the action items and tasks to be completed in response to events which impact the Company’s electric distribution system, to assure effective, efficient, and timely mitigation of hazards and restoration of service.

A Red Alert will be issued 0-12 hours in advance of the following conditions being experienced on the electric distribution system:

1. Severe weather is imminent
2. Extreme temperatures are being experienced
   a. 5°F or lower
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b. 90°F or higher
3. Sustained wind speeds or wind gusts greater than 40 miles per hour are being experienced
4. Ice accretion totals equal to or greater than 0.25 inches are being experienced
5. Flooding is occurring
6. A natural disaster is experienced
7. A significant manmade disaster is experienced

Task lists associated with each alert level shall be developed for critical storm roles and business functions as defined throughout this Emergency Preparedness and Response Plan.
1.2. Emergency Event Levels

At the onset of most significant outage events, it is difficult to accurately determine the extent of system damages prior to performance of damage assessment surveys in the field. Electric Distribution has established four emergency level definitions to help classify damage and outage levels, predict resource needs, and effectively execute organizational, safety, and communications plans.

- **Level I** - A level I emergency is defined as an outage event on the electric distribution system that is expected to be resolved within six (6) hours and requires the use of local Company personnel and resident contractors to restore service and make necessary repairs.

- **Level II** - A Level II emergency is defined as an outage event on the electric distribution system that is expected to be resolved within six (6) to twenty four (24) hours and requires the use of regional Company personnel and resident contractors. Typically, the Distribution Control Center (DCC) continues to control the electric distribution system, assign hold cards, and dispatch field crews.

- **Level III** - A Level III emergency is defined as an outage event on the electric distribution system that is expected to be resolved within twenty four (24) to seventy two (72) hours. This level of event requires the use of all available company personnel and resident contractors, and usually necessitates the utilization of off-system resources secured via mutual assistance or existing business partner relationships. This level of event also typically necessitates that the DCC decentralize event prioritizations and assignment processes to local resource managers.

- **Level IV** - A Level IV emergency is defined as an extreme outage event on the electric distribution system that will require more than seventy two (72) hours to resolve and jeopardizes the general health and welfare of customers and the communities the Company serves. This level of event requires the use of all available company personnel and resident contractors, and necessitates the utilization of off-system resources secured via mutual assistance or from existing business partner relationships. This level of event also typically necessitates that the DCC decentralize event prioritizations and assignment processes to local resource managers.
Incident Commanders and Operations Section Chiefs shall be jointly responsible for constantly monitoring outage counts and system conditions and determining the level of an outage event.
1.3. Emergency Preparedness, Planning, and Response

1.3.1. Incident Command

Electric Distribution has adopted an Incident Command System (ICS) structure for responses to emergencies and outage events (see Sections 3.0-9.0). The structure is based on components of the National Incident Management System (NIMS), and accommodates all types and sizes of emergencies. The organizational structure and associated processes also provide assurance the Company responds to events on the electric system in a timely, effective, and consistent manner. Finally, the ICS provides for standard communications during emergencies, to key stakeholders, both internal and external to the Company.

The Company’s Incident Command organization contains key leadership roles, including:

- Executive Officers
- Safety Officers
- Communications Officers
- Incident Commander
- Operations Section Chiefs
- Customer Experience Section Chiefs
- Logistics Section Chiefs
- Work Planning Section Chiefs

Electric Distribution partners with Corporate Communications, Safety and Technical Training, Supply Chain, Facilities, and Customer Services to staff at least two senior leadership personnel to each key leadership role identified above.

1.3.2. Emergency Preparedness and Response Team

All personnel assigned to an IC key leadership role are also assigned to an *Emergency Planning, Preparedness, and Response Team* (EPPRT). The EPPRT meets monthly to develop emergency response strategies, review preparedness plans, assure completion of preparation tasks, conduct post incident reviews, and stay abreast of external (industry and customer) factors which influence emergency response processes and strategies.

The EPPRT is responsible for developing and maintaining emergency preparedness and response plans, procedures, and strategies which assure the Company effectively responds...
to emergencies and significant outage events on the LG&E and KU distribution systems.

See Appendix 1.A to see the Emergency Preparedness and Response Team members.

1.3.3. Emergency Preparedness, Planning, and Response Plan

Prior to April 1st each year, all Section Chiefs shall review EPRP procedures, guidelines, and checklists for responses to significant emergencies and outage events and revise them as deemed necessary to incorporate regulatory requirements and lessons learned. Electric Distribution’s Emergency Planning and Preparedness Manager shall be responsible for overseeing the review process, and ensuring completion in accordance with established schedules. During the review process, Section Chiefs or their delegate(s) shall verify employee assignments to key roles, and ensure all necessary training is provided.

Each Section Chief or responsibility area shall be responsible for reviewing assigned contact lists twice per year, including:
- All Company personnel and business partners assigned storm roles;
- Mutual aid companies and business partners;
- State, county, and local elected officials;
- State, county, and local emergency response agencies;
- Providers of key services and supplies
- Operators and managers of lodging facilities and food services;
- Medical facilities


1.3.4. Training

The EPPRT and Emergency Planning and Preparedness Manager are responsible for overseeing the development and execution of training plans covering the Emergency Preparedness and Response Plan. (Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.) Each Incident Command Officer or Section Chief shall be responsible for ensuring the training plan is executed.
1.3.5. Exercises

The EPPRT and Electric Distribution’s Emergency Planning and Preparedness Manager shall be responsible for overseeing the development and execution of an annual exercise or drill that tests the adequacy and effectiveness of all aspects of Electric Distribution’s emergency response plan and procedures, and provide assurance that adequate qualified personnel are available to respond to Level I - IV events across the LG&E and KU footprint.

Each Incident Command Officer or Section Chief shall be responsible for conducting at least annual exercise of their responsibility areas to ensure all emergency response business processes and key roles are tested, and to provide refresher training for employees and business partners assigned to their Section.

*Appendix 1.D contains a copy of the standard form to be used for documenting exercise objectives, descriptions, and results.* All Exercises shall be documented on this form. Completed forms shall be submitted to Electric Distribution’s Emergency Planning and Preparedness Manager, who will retain a record of the Exercise for no less than seven years.

1.3.6. After Action Reviews

At the conclusion of each Level III or IV event, a post storm After Action Review (AAR) shall be conducted by the EPPRT or their delegates to assess the effectiveness of the response and EPRP and to identify improvement opportunities that may be needed. Electric Distribution’s Emergency Preparedness and Response Manager shall be responsible for collecting all submitted enhancement opportunities and working with the EPPRT to develop and prioritize action plans and assign accountability for completion. *Appendix 1.3.E contains a copy of the standard After Action Review form to be utilized.*
1.4. Weather and System Monitoring

The Electric Distribution Control Centers and Director Electric System Restoration and Distribution are responsible for monitoring weather and other conditions, evaluating their severity, and estimating their potential impacts on the electric delivery system. Any incident or event that poses a significant threat to the electric system and the deliverability of power should be immediately communicated to the Vice-President Electric Distribution Operations or their delegate and the responsible Incident Commander(s). Whenever a significant weather event or incident capable of causing interruptions to electric service does or is anticipated to occur, the Incident Commander, with support from the Operations Section Chiefs, shall establish and communicate the appropriate Alert Level, in accordance with EPRP 1.1.

1.4.1. Weather Monitoring Services

The Distribution Control Center and Director Electric System Restoration utilize the following weather services and resources to monitor and assess weather events that could negatively impact the electric system and cause a substantial loss in electric service:

1.4.1.1. Louisville National Weather Service

The Director System Restoration or a delegate and the Distribution Control Center review National Weather Service (NWS) forecasts daily (http://www.crh.noaa.gov/lmk/) to monitor and plan for events which are forecasted to cause conditions which have a history of producing outages or system damages on the LG&E and KU electric delivery systems. The Director System Restoration or a delegate utilizes NWS weather data as the primary resource for establishing Yellow and Red Alerts, as described in EPRP 1.1.

The Louisville NWS Meteorologist in Charge (MIC) notifies the Director Electric System Restoration via email whenever the NWS plans to hold a conference call regarding forecasted or ongoing weather events which could meet severe criteria. The Director Electric System Restoration or their delegate participate in all scheduled NWS conference calls regarding weather advisories, watches or warnings which may impact the LG&E or KU service areas.
1.4.1.2. **StormGeo Weather Service**

The Director System Restoration and Distribution Control Center subscribe to Storm Geo Weather service (http://customers.stormgeo.com/portal/login) to supplement the National Weather Service weather information. StormGeo provides an outsourced 24/7/365 weather department that provides 24/7 access to meteorologists and dedicated client service team member. The service includes customized weather website configured for both Transmission and Distribution, periodic weather threat outlooks, event (storm) specific advisories and site specific alerts, approximate 450x200 mile lightning detection area, advanced lightning modeling for dangerous thunderstorms and tornado alerting, and Business Decision Guidance dashboard which is a risk assessment tool that utilizes historical weather and outage data.

1.4.1.3. **Schneider Electric – MxVision Weather Sentry Online, Utility Edition**

The Director System Restoration and Distribution Control Center subscribe to Schneider Electric’s MxVision Weather Sentry Utility Edition (http://weather.dtn.com/dtnweather/common/link.do?contentId=600024&parentId=300001) to supplement the National Weather Service weather information. This service provides fifteen (15) day forecasts, which include all pertinent weather data. Also, the service provides real time weather radar, coupled with watch and warning areas, wind speeds, precipitation type, and lightning data. Finally, Weather Sentry’s forecasting service provides dedicated meteorologists 24x7 to respond to weather questions. Weather questions are typically answered within 15 minutes of submission.

1.4.1.4. **Sperry-Piltz Ice Accumulation Index**

Whenever the National Weather Service forecasts icing in the LG&E or KU service areas, the Director Electric System Restoration and Distribution, or their delegate, and the Distribution Control Center review the Sperry-Piltz Ice Accumulation Index (http://www.spia-index.com/nelce.php) for the Northeast region, to predict system damages and impacts for forecasted ice accumulations, temperatures, and wind speeds.

1.4.1.5. **Weather Underground**
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The Distribution Control Center utilizes Weather Underground (http://www.wunderground.com/) to supplement National Weather Service and Weather Sentry weather data, and to review or gather historical weather data associated with a significant outage event.

1.4.2. Emergency Management Situation Reports

Electric Distribution’s Emergency Planning and Preparedness Manager and Business Continuity Coordinator work with Emergency Management Agencies to stay abreast of weather conditions or other events which could significantly impact the LG&E and KU electric systems. Both positions are responsible for reviewing all Emergency Situation Reports released by Kentucky or Virginia Emergency Management, and evaluating them to assess and prepare for evaluated risks.
2. Notification Procedures

**Purpose**
The purpose of EPRP Section 2.0 is to provide personnel with an overview of mandated reporting requirements for significant system outages. This Section is intended to supplement and not replace internal and external reporting requirements established in the Company’s *Internal Notification/Emergency Response Guide* (INERG). *(A copy of the INERG is available in Appendix 2.A)*

The INERG shall be made available or provided to all Company personnel who respond to emergencies or significant outage events on the electric distribution system. It provides internal reporting requirements for emergencies and outage incidents to assure regulatory reporting requirements are satisfied, and must be adhered to by all personnel.

**Scope**
The scope of EPRP Section 2.0 covers all Company electric distribution facilities and customers under the jurisdiction of the Kentucky Public Service Commission or Virginia State Corporation Commission.

**Responsibilities**
The Manager – Distribution Control Center or his/her delegate shall have responsibility for meeting the reporting requirements established herein.

**Training and Qualification**
The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. *(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)*

**References**
1. 807 Kentucky Amended Regulations(KAR) Part 5.006 Section 27

**Revisions**
None

The Kentucky Public Service Commission (KPSC) requires notification from the Company within two (2) hours following discovery of any single incident in an operations center area which results in a service interruption for four (4) or more hours to 500 or more customers.

The Distribution Control Center Manager or his/her designee shall be responsible for completing necessary electronic service interruption notifications per KPSC and internal guidelines. The following link must be used to submit KY PSC notifications: http://psc.ky.gov/Security/Account/login.aspx

(A copy of all submitted reports must be submitted internally to Company personnel listed in Appendix 2.B.)
2.2. Virginia State Corporation Commission - Outage Notification Procedures

The Virginia State Corporation Commission (VSCC) requires notification from the Company of any single incident in an operations center area which results in any outages that are thirty (30) or more minutes in duration affecting service to 10% of the customers of a utility. Notification shall be made by telephone as soon as practical during the regular business day or promptly in the morning of the following business day if the interruption occurs during non-business hours.

The Distribution Control Center Manager or his/her designee shall be responsible for completing necessary telephone and written notifications per VSCC guidelines as outlined in October 16, 1985 letter regarding Reporting of Bulk Power Supply Emergencies and Electric Power Outages. (A copy of all submitted reports must be submitted internally to Company personnel listed in Appendix 2.B.)
2.3. Emergency Incident Internal Notification Procedures

The procedures described herein align with the Company’s *Internal Notification and Emergency Response Guide (INERG)* which is included in Appendix 2.A. The scope of this section includes INERG covered emergency incidents which may be experienced during responses to significant outage events on the electric distribution system.

2.3.1. Reportable Incidents to State Commissions

Section 2.1 and 2.2 of this EPRP establish the Kentucky Public Service Commission’s and Virginia State Corporation Commission’s minimum reporting requirements for covered emergency incidents. The Director Safety and Technical Training or their delegate should be notified of any Covered Emergency Incident which is reportable, or has the potential to be reportable, to the KYPSC or V SCC.

2.3.2. Sabotage Reporting

Sabotage is broadly defined as disturbances or unusual occurrences intended to cause failure, disruption, or harm to the normal business activities, property, or operations of LG&E, KU, or ODP. Employees and contract employees who are made aware of actual or suspected sabotage shall immediately contact Corporate Security.

Employees will be alerted when an incident has occurred within the Company, and will be advised on the appropriate actions to take. Employees may call designated sabotage information lines (see Appendix 10) to obtain necessary information regarding a reported sabotage incident.

2.3.3. Incident Investigation

The Company’s Fire and Security Investigator (FSI), or their designee, should be notified of all covered emergency incidents. The FSI, or their delegate, is responsible for investigating all reported incidents. Corporate Law shall be contacted in the event the FSI or their designee is not available (see Appendix 10 for contact information).

- The Director Safety and Technical Training should be notified of any safety incident which has or will likely result in an OSHA investigation.
• The Manager Corporate Security and Business Continuity should be notified whenever there is knowledge of a fatality or newsworthy event (see Appendix 10 for contact information).

2.3.4. Media Contacts

Corporate Communications shall be contacted (see Appendix 10 for contact information) whenever an INERG covered emergency incident occurs and there is potential or known media coverage.

2.3.5. Environmental Spills or Releases

Electric Distribution Company and contractor employees should take the following actions whenever there is a release of transformer oil, petroleum product, or hazardous chemicals.

A. Identify spilled substance, spill source and affected area.
B. Notify immediate supervisor, and determine who will make necessary external notifications.
C. Stop and contain the spill if trained and qualified to do so.
D. Notify local emergency response agencies within 15 minutes. Call 911 if the spill triggers Reportable Quantity (RQ) procedures.
E. Notify Environmental Affairs and the appropriate regulatory authorities (see Appendix 10.0 for contact information).

When a potentially hazardous spill has occurred, the following information must be reported:

A. Name and position of the person reporting
B. Spill area description
C. Spill location, source, and cause
D. Time of spill/incident
E. Material involved
F. Corrective action(s) taken
G. Estimated spill size/quantity released
2.3.6.  Asbestos Emergencies

Any employee exposed to a possible Asbestos Containing Material (ACM) shall notify their immediate supervisor or manager and designated Safety and Technical Training Specialist.

2.3.7.  Critical Incident Reporting to PPL

In the event of a serious safety or security incident involving LG&E or KU that requires reporting to a regulatory authority, the PPL Security Command Center must be notified in accordance with the following:

A.  **Employee or Contractor Injury** - Director Safety and Technical Training
B.  **Security Incident** - Manager Corporate Security and Business Continuity

Notifications must be made within 24 hours of reporting to a regulatory authority, but timing should be accelerated based upon the severity and circumstances of the incident.
3. Incident Command System

**Purpose**
The purpose of EPRP Section 3.0 is to introduce the high level organizational structure, command staff, and associated responsibilities the Company shall employ when responding to significant emergencies or outage events on the electric distribution system.

**Scope**
The scope of EPRP Section 3.0 covers the Company’s electric distribution service territory, and all personnel, business partners and off system resources utilized in response to emergencies or significant outage events on the LG&E, KU, or ODP electric distribution system.

**Responsibilities**
The Emergency Preparedness, Planning, and Response Team (EPPRT) shall have responsibility for assuring all resources available and assigned to assist with an emergency or significant restoration event are organized in accordance with the procedures described herein. Additionally, the EPPRT shall have responsibility for developing Alert Level Task lists for the Incident Command areas under their responsibility. **Appendix 3.B contains Alert Task Lists for key Electric Distribution Incident Command System areas.**

**Training and Qualification**
The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.**

**References**
None

**Revisions**
None
3.1. Incident Command System Command Staff

Electric Distribution has adopted an Incident Command System (ICS) based structure for responses to significant emergencies and outage events on the Company’s electric distribution system. The organizational structure and command staff positions of the Company’s ICS are displayed in Figure 1. (See Appendix 3.A for names, titles, and contact information of designated command staff personnel.)

![Diagram of Incident Command System Command Structure]

This structure and associated processes provide assurance the Company responds to events on the electric system in a timely, effective, and consistent manner. Finally, the ICS provides for standard communications during emergencies, to key stakeholders, both internal and external to the Company.

The chain of command throughout the ICS is used to communicate direction and maintain management control. Although direction must flow through the chain of command, members of the organization may directly communicate and work with each other to ask for or share information. ICS team members work within the ICS position descriptions and follow the designated reporting relationships, regardless of their non-emergency positions or everyday reporting responsibilities.
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3.2. Executive Officers

The Vice President Electric Distribution and the Vice President Customer Services or their
designee(s) shall serve as Executive Officer(s) for significant emergency response efforts
associated with the Electric Distribution System. These positions shall also be responsible for
serving as Executive Sponsors of the Emergency Planning, Preparedness, and Response Team
(see EPRP 1.3), and overseeing the development and maintenance of Alert Level task lists (see
Appendix 3.B) which assure the Company is sufficiently prepared to safely respond to significant
electric outage events and associated emergencies.

3.2.1. Emergency Preparedness

Executive Officers shall be responsible for executing Blue Sky Task List items throughout
the year to assure LG&E and KU are prepared to safely respond to all significant electric
outage events and related emergencies, including:

- Ensure the Company is adequately organized, trained, and exercised to respond
  safely, efficiently and effectively.
- Ensure human, equipment, and material resource plans provide for effective and
timely responses.
- Ensure effective communications plans are in place to provide customers,
  emergency responders, community leaders, and employees with timely and
  accurate information during events.
- Ensure the Company’s emergency planning, preparedness, and response practices
  align with Industry best practices.
- Ensure effective preparedness plans are in place with customers, key emergency
  response agencies, government leaders, and other private sector organizations.

3.2.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated
Executive Officers shall be responsible for executing all Executive Officer Yellow Alert
Task List items. Pre-event planning responsibilities include:

- Collaborate with the Incident Commander to evaluate threats and develop strategic
  response plans.
- Ensure all key Company Officers are informed of forecasted threats.
- Collaborate with the Information Officer as necessary to develop internal and
  external communications strategies.
Collaborate with the Incident Commander and other Section Chiefs to ensure assigned Company personnel are executing designated Yellow Alert task items.

Work with the Incident Commander as needed to assess and approve resource plans.

3.2.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, designated Executive Officers shall be responsible for executing all assigned Red Alert Task List items. During significant outage events or emergencies, Executive Officer’s responsibilities include:

- Conduct continuous situational awareness meetings and communications with key internal and external leaders.
- Oversee and support execution of established emergency response plans.
- Ensure the organization is adequately organized, staffed, and positioned to respond.
- Ensure safety is tightly integrated into all response plans and procedures.
- Oversee development and execution of key internal and external communications strategies.
3.3. Information Officer

The Director of Media Relations and the Director of External and Brand Communications (or their designee(s)) shall serve as Information Officer(s) for significant emergency response efforts associated with the Electric Distribution System. These positions shall also be responsible for serving on the *Emergency Planning, Preparedness, and Response Team* (see EPRP 1.3), and developing and maintaining Alert Level task lists (see Appendix 3.B) which assure the Company is sufficiently prepared to effectively communicate internally and externally in preparation for or response to significant outage events or emergencies involving the electric distribution system.

3.3.1. Emergency Preparedness

Designated Information Officers shall be responsible for executing *Blue Sky Task List* items throughout the year to assure LG&E and KU are prepared to safely respond to all emergencies, including:

- Oversee development and maintenance of all tactical and strategic communication plans and procedures associated with emergency response and system restoration and repair.
- Validate position specific task lists.
- Ensure that all support staff has been identified and adequately trained.
- Work with industry leaders to develop procedures and industry guidelines for resolving inconsistent safety practices and procedures of mutual assistance utility and business partners.

3.3.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Information Officer shall be responsible for executing all Information Officer *Yellow Alert Task List* items. Pre-event planning responsibilities include:

- Collaborate with the Incident Commander and Operations Section Chief to determine the predicted event level and scope.
- Assign support team members – communication professionals – to the service areas with forecasted trouble.
- Collaborate with the Executive Officer and Incident Commander as necessary to develop internal and external communication strategies.
3.3.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the designated Information Officer shall be responsible for executing all assigned Red Alert Task List items. During significant outage events or emergencies, Information Officer’s responsibilities include:

- Collaborate with Incident Commander and Operations Section Chief to determine actual damages and system impact.
- Collaborate with Executive Officer and Incident Commander to develop internal and external communication strategies.
- Execute key internal and external communications strategies.
- Deploy support team members – communication professionals - to the service areas with significant customer outages and damages.
3.4. Safety Officer

The Director Safety and Technical Training and Manager Electric Distribution and Transmission Safety or their designee(s) shall serve as Safety Officer(s) for significant emergency response efforts associated with the Electric Distribution System. These positions shall also be responsible for serving on the Emergency Planning, Preparedness, and Response Team (see EPRP 1.3), and developing and maintaining Alert Level task lists (see Appendix 3.B) which assure the Company is effectively protects customers, the public, employees, business partners, emergency responders, and all personnel supporting the Company’s response to emergencies and significant outage events involving the electric distribution system.

3.4.1. Emergency Preparedness

Designated Safety Officers shall be responsible for executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to safely respond to all emergencies, including:

- Oversee development and maintenance of all technical, tactical, and strategic safety plans and procedures associated with emergency response and system restoration and repair, which assure the safety of employees, business partners, off-system resources, and the public.
- Assist with the development, oversight, and assessment of emergency response drills and exercises which test the effectiveness of emergency response procedures.
- Validate position specific task lists.
- Ensure that all support staff has been identified and adequately trained.
- Develop and maintain off-system resource passporting processes and tailgate material.
- Work with industry leaders to develop procedures and industry guidelines for resolving inconsistent safety practices and procedures of mutual assistance utility and business partners.

3.4.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Safety Officer shall be responsible for executing all Safety Officer Yellow Alert Task List items. Pre-event planning responsibilities include:

- Collaborate with the Incident Commander and Operations Section Chief to determine the predicted event level and scope;
3.4.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the designated Safety Officer shall be responsible for executing all assigned Red Alert Task List items. The Safety Officer has responsibility for assessing hazards and unsafe conditions associated with the incident, and developing, implementing, and monitoring an incident safety plan which assures:

- Public and personnel safety;
- All personnel responding to the incident are properly trained and qualified to perform restoration and repair activities;
- All Command Staff personnel are kept up to date on safety performance and any incidents;
- All personnel responding to the incident are aware of identified safety hazards and unsafe conditions;
- Assure a Safety Hotline is managed throughout an event to provide employees, contractors, and mutual assistance resources the opportunity to submit any safety concerns.
- All off-system resources receive safety passport training;
- Adequate safety professional representation is in the field; and
- Safety performance is monitored and reported on throughout the restoration effort.
3.5. Incident Commander

The Director Electric System Restoration shall be responsible for overseeing the Emergency Planning, Preparedness, and Response Team (see EPRP 1.3), and serving as the primary Incident Commander for significant outage event emergencies involving the Electric Distribution System. The Director of Customer Services Energy Efficiency & Smart Grid Strategy shall serve as the secondary Incident Commander. Both of the defined positions shall also be responsible for serving on the Emergency Planning, Preparedness, and Response Team (see EPRP 1.3), and developing and maintaining Alert Level task lists (see Appendix 3.B) which assure the Company is sufficiently prepared to safely respond to emergencies and significant electric outage events.

3.5.1. Emergency Preparedness

The primary Incident Commander, or a designee, shall be responsible for executing all Blue Sky Task List items to assure LG&E KU is adequately prepared to respond to significant outage events on the electric distribution system, including:

- Coordinating, planning, and leading monthly planning and preparedness meetings;
- Working with responsible Section Chiefs to develop preparedness, planning, and response task lists for each Incident Command Section;
- Directing, planning, and participating in annual emergency drills which exercise the Emergency Preparedness and Response Plan, and Alert Level Task lists;
- Ensuring that adequate personnel are designated and trained to fill critical Incident Command System positions; and
- Directing, leading, or supporting post incident reviews.

3.5.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the Incident Commander shall be responsible for establishing an Yellow Alert (see EPRP 1.1), and executing all Yellow Alert Task List items. Pre-event planning responsibilities include:

- Directing the staffing and coordination of Electric Distribution’s Incident Command System Command Staff;
- Alerting the Command Staff and the Vice President – Electric Distribution Operations of Emergency Preparedness and Response Alert Level revisions and establishing the anticipated Emergency Event Level classification (see EPRP 1.2) for the LG&E KU service areas; and
3.5.3. Emergency Response
Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the Director Electric System Restoration or their designee shall be responsible for establishing an Red Alert (see EPRP 1.1), and executing all Incident Commander Red Alert Task List items.

During response to significant outage events, the Incident Commander shall be designated by the highest ranking qualified management representative that is available to lead the Company’s response at the time of an incident. The Incident Commander’s authorities and responsibilities shall be transferred to more higher ranking and qualified personnel when they are available to respond and assume the role.

The Incident Commander is responsible for overall management of an incident, for ensuring compliance with applicable internal policies and government regulations, and for determining strategic and tactical objectives. The Incident Commander is ultimately responsible for public and personnel safety, resource management, and internal and external information releases.

The Incident Commander shall also be responsible for:
- Directing the staffing and coordination of Electric Distribution’s Incident Command System Command Staff;
- Establishing a Command Post if one has not been set up.
- Ensuring public safety and the safety of all resources supporting system restoration or emergency response efforts.
- Maintaining communications with senior management regarding status, activities, and issues to ensure tactical responses align with strategic goals and objectives.
- Coordinating response activities with incident response emergency response agencies and government officials.
- Coordinating work activities between work groups representing various phases of operations.
- Ensuring safety performance, system status, resource levels, regulatory issues, and all external communications are logged.
• Ensuring appropriate delegation of authority has been transferred to satisfy all needed positions and optimize resources.

The Incident Commander is responsible for establishing and monitoring the incident organization. The organization should be large enough to manage the incident at hand, yet, resource use must be efficient and cost effective. Anticipated expansion or contraction of incidents shall require changes to the organization.
3.6. Operations Section Chief

The Director Electric Distribution and Director Asset Management or their designees shall serve as Operations Section Chiefs for significant emergency response efforts associated with the Electric Distribution System. Designated Operations Section Chiefs shall be responsible for serving on the Emergency Planning, Preparedness, and Response Team (see EPRP 1.3), and developing and maintaining Emergency Preparedness and Response Alert Level task lists (see Appendix 3.B) associated with their Section responsibilities.

3.6.1. Emergency Preparedness

Operations Section Chiefs shall also be responsible for overseeing and executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to safely, effectively and efficiently respond to all emergencies, including:

- Overseeing the development and maintenance of effective business processes, and ensuring a sufficient number of personnel are trained and qualified, to protect the public from reported downed wires;
- Sufficiently staffing, equipping, and training personnel to perform post event damage assessments and accurately estimate restoration durations;
- Ensuring adequate facilities are available and equipped to support central resource management and work prioritization operations;
- Ensuring an adequate number of personnel and business partners are trained and qualified to support resource management and work prioritization restoration and repair processes; and
- Assisting with development of, and supporting, all exercises that test Emergency Preparedness and Response procedures.

3.6.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Operations Section Chiefs or their delegate(s) shall be responsible for executing all assigned Yellow Alert Task List items. Pre-event planning responsibilities include:

- Ensuring all key Operations Section roles and responsibilities are filled, commensurate with the predicted Event level and response needed;
- Developing tactical plans for aligning needed resources with service areas forecasted to experience trouble;
- Collaborate with Work Planning to ensure resource availability information is available; and
3.6.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Operations Section Chief(s) shall be responsible for executing all assigned Red Alert Task List items, including:

- Ensuring all key roles of the Operations Section (see EPRP 6.0) are filled, as needed based on the forecasted or actual outcome of an event;
- Working with Work Planning to ensure all resources are accounted for in the designated Resource Management database;
- Executing and supporting Damage Assessment Procedures to enable timely and effective gathering and assessment of system damages;
- Working with the Operations Managers and Work Planning to estimate/identify resource needs and restoration projections based on those needs;
- Developing and overseeing tactical plans which support Protect, Restore, Repair philosophies; and
- Assuring effective and efficient assignment and utilization of available resources to execute restoration and repair procedures;
3.7. Customer Experience Section Chief

The Director Customer Service and Marketing and Director Revenue Integrity or their designee(s) shall serve as Customer Experience Section Chiefs for significant emergency response efforts associated with the Electric Distribution System. These positions shall also be responsible for serving on the Emergency Planning, Preparedness, and Response Team (see EPRP 1.3), and developing and maintaining Alert Level task lists (see Appendix 3.B) which assure the Company is sufficiently prepared to safely respond to emergencies and significant electric outage events.

3.7.1. Emergency Preparedness

Customer Experience Section Chiefs shall be responsible for overseeing and executing Blue Sky Task List items throughout the year, including:

- Sufficiently staffing, equipping, and training personnel and business partners to assure effective responses to customer outage notifications;
- Ensuring adequate procedures are in place to identify and communicate with critical, key, and major customers during large outage events or emergencies involving the electric system.
- Ensuring adequate procedures are in place to communicate critical, key, and major customer information to internal stakeholders during large outage events or emergencies involving the electric system.
- Developing and testing business procedures for properly elevating emergency contacts.
- Assisting with development and support of all exercises that test emergency response and restoration Customer Experience procedures.
- Establishing effective relationships with key state, regional, and local emergency managers.

3.7.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Customer Experience Section Chiefs or their delegate(s) shall be responsible for executing all assigned Yellow Alert Task List items. Pre-event planning responsibilities include:

- Ensuring all key Customer Experience Section roles and responsibilities are scheduled or filled, commensurate with the predicted Event level and response needed;
• Communicating with information technology to ensure all information Customer information systems will be available for the period where inclement weather is forecasted; and
• Communicating with the Logistics Section Chief(s) or their delegate to ensure necessary resource tracking information is available.

3.7.3. Emergency Response
Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Customer Experience Section Chief(s) shall be responsible for executing all assigned Red Alert Task List items, including:
• Ensuring all key roles of the Customer Experience Section (see EPRP 7.0) are filled, as needed, based on the forecasted or actual outcome of an event;
• Collaborating with the Incident Commander and Information Officer to ensure consistent information is being communicated to customers, local authorities, emergency operations centers, and government entities.
• Verifying all available communications channels are working properly and allowing affected customers to identify outages and obtain restoration status information.
• Verifying with Information Technology that all necessary information systems are available;
• Assuring key customer outage statistical and performance data is tracked and provided to the Incident Commander.
• Working with Budgeting and Forecasting to ensure all necessary resource information is available for required financial reporting;
• Ensuring effective emergency management outreach to affected emergency response managers, and staffing or support of all activated Emergency Operations Centers as requested by key state, regional, or city officials.
• Ensuring effective and timely communications with major and key customers who need critical restoration information and assistance during restoration activities.
• Working with areas affected by outages or emergencies and making local business offices available for customers to provide outage information and obtain updates on their restoration status.
3.8. Logistics Section Chief

The Director Supply Chain and Director Operating Services or their designee(s) shall serve as Logistics Section Chief(s) for significant emergency response efforts associated with the Electric Distribution System. Designated Logistics Section Chiefs shall be responsible for serving on the Emergency Planning, Preparedness, and Response Team (see EPRP 1.3), and developing and maintaining Emergency Preparedness and Response Alert Level task lists (see Appendix 3.B) associated with their Section responsibilities.

3.8.1. Emergency Preparedness

Logistics Section Chiefs shall be responsible for overseeing and executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to effectively and efficiently meet logistical, security, and human needs of resident and off system resources during responses to significant outages or emergencies on the electric system, including:

- Prearranging for staging areas and facilities for restoration resource management, housing, staging, and resource processing;
- Developing staging, housing, and meals contracts and business processes which assure adequate and efficient support of emergency and restoration responses;
- Ensuring an adequate number of personnel and business partners are trained and qualified to support the provision and/or set up of staging areas, meals, fueling, housing, facilities, laundry services, waste management, materials, security, etc...during responses to significant outages or emergencies;
- Assisting with the development of, and participating in all drills and exercises that test Emergency Preparedness and Response procedures.

3.8.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Operations Section Chiefs or their delegate(s) shall be responsible for executing all assigned Yellow Alert Task List items. Pre-event planning responsibilities include:

- Ensuring all key Logistics Section roles and responsibilities are identified and staffed, commensurate with the predicted Event level and response needed and communications have been made with all personnel who might be mobilized to support an event;
- Collaborating with the Incident Commander and Work Planning group to develop tactical plans for staging areas, meals, fueling, housing, facilities, laundry services,
waste management, materials, security, and communications as needed to support the resources needed for the event forecasted;

- Contacting, as needed, logistics vendors and business partners to discuss the pre-positioning of resources depending on the anticipated event impacts; and
- Confirming the availability of anticipated material needs, and arranging for the delivery of incremental storm kits and material trailers, as needed for operating areas forecasted to be impacted.

3.8.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Logistics Section Chief(s) or their designee shall be responsible for executing all assigned Red Alert Task List items, including:

- Ensuring all key roles of the Logistics Section (see EPRP 9.0) are staffed and backed-up, as needed based on the forecasted or actual outcome of an event;
- Assuring effective and efficient assignment and utilization of available resources to execute established logistics procedures;
- Serving as a single point of contact for the Incident Commander, Operations Section Chiefs, and Work Planning Section Chiefs, for coordinating material and supply requirements, inventory management, and logistics field operations across all impacted areas;
- Identifying and estimating service and support requirements for planned and expected operations;
- Working with Work Planning to ensure adequate staging locations, hotels, meals, etc...are available for all resources accounted for in the designated Resource Management database; and
- Assisting with demobilization procedures for all off system resources.
3.9. Work Planning Section Chief

The Director Electric Reliability and Manager Design or their designee(s) shall serve as Operations Section Chiefs for significant emergency response efforts associated with the Electric Distribution System. Designated Work Planning Section Chiefs shall be responsible for serving on the *Emergency Planning, Preparedness, and Response Team* (see EPRP 1.3), and developing and maintaining Emergency Preparedness and Response Alert Level task lists (*see Appendix 3.B.*) associated with their Section responsibilities.

3.9.1. Emergency Preparedness

Work Planning Section Chiefs shall be responsible for overseeing and executing *Blue Sky Task List* items throughout the year, including:

- Overseeing the development and maintenance of emergency restoration resource management tracking databases, applications, reports, and business processes;
- Working with the Operations Section Chiefs and Incident Commander to develop business processes which support resource needs calculations and mutual assistance business processes;
- Sufficiently staffing, equipping, and training personnel to assist with resident and non-resident resource planning, acquisition, administration, and tracking;
- Ensuring adequate facilities are available and equipped to support central and decentralized resource planning and tracking business processes;
- Assisting with development of, and supporting, all exercises that test emergency response and restoration Work Planning procedures.

3.9.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Work Planning Section Chiefs or their delegate(s) shall be responsible for executing all assigned *Yellow Alert Task List* items. Pre-event planning responsibilities include:

- Ensuring all key Work Planning Section roles and responsibilities are scheduled or filled, commensurate with the predicted Event level and response needed;
- Working with the Operations Section Chief and Incident Commander to calculate and equitably allocate needed resources for service areas forecasted to experience trouble;
- Collaborating with the Incident Commander and Operations Section Chief to establish industry and business partner mutual assistance tactical plans;
- Participating on necessary mutual assistance calls;
• Communicating with information technology to ensure all information systems will be available for the period where inclement weather is forecasted; and
• Communicating with the Logistics Section Chief(s) or their delegate to ensure necessary resource tracking information is available.

3.9.3. Emergency Response
Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Work Planning Section Chief(s) shall be responsible for executing all assigned Red Alert Task List items, including:
• Ensuring all key roles of the Work Planning Section (see EPRP 8.0) are filled, as needed based on the forecasted or actual outcome of an event;
• Working with the Operations Section to ensure all resources are accounted for in the designated Resource Management database;
• Working with the Operations Section to establish area specific resource needs and availability, including line technicians, service crews, bird dogs, bull dogs, and damage assessors;
• Participating on necessary mutual assistance calls;
• Executing necessary internal resource reporting;
• Verifying with Information Technology that all necessary information systems are available;
• Working with Budgeting and Forecasting to ensure all necessary resource information is available for required financial reporting;
• Executing all mutual assistance business processes, including participating on joint mobilization mutual assistance conference calls, tracking resources from the point of release to the assignment to an operations area, and assisting the Operations Section with administratively processes arriving resources; and
• Coordinating with the Operations Section and Incident Commander to monitor and modify estimated restoration durations for local areas and at circuit levels, and helping to effectively align, secure or assign resources with system damages and outage counts.
4. **Safety**

**Purpose**
The purpose of EPRP Section 4.0 is to outline incremental safety procedures, processes, and organization setup which may be utilized during responses to emergencies, disasters, or weather events which result in significant damages and customer outages on Company electric distribution facilities. All safety policies and procedures included in the References section below shall continue to be adhered to.

**Scope**
The scope of EPRP Section 4.0 covers the Company’s electric distribution service territory, and all personnel, business partners and off system resources utilized in response to emergencies or significant outage events on the LG&E, KU, or ODP electric distribution system.

**Responsibilities**
The EPPRT shall have responsibility for assuring all resources available and assigned to assist with an emergency or significant restoration event are aware and knowledgeable of all safety policies and procedures associated with the work to be performed.

**Training and Qualification**
The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. *(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)*

**References**
2. LG&E and KU Energy LLC Policy, Corporate Health and Safety Policy, Version - 12/10/08.
3. LG&E and KU Energy LLC Policy, Safety Reinforcement, Version - 12/10/08.

**Revisions**
None
4.1. Passporting Off System Resources

During significant events on the Electric Distribution system, when significant damages and customer outages result, Electric Distribution may secure incremental off system resources to assist with restoration efforts. The Operations Director or their designee(s) shall be responsible for assuring that no off system worker is permitted to work on the LG&E and KU system until they have received prescribed safety orientation/passport training.

Each Operations Director shall be responsible for working with the Safety Officer or their designee to identify locations where Safety Specialists or an alternative qualified resource is needed to conduct standardized safety briefings with off system contractors and utility workers. In the event a Safety Specialist or alternative resource cannot be assigned to the Operations location where off system resources are assigned, the Operations Director or their designee shall be responsible for assuring a qualified person under their responsibility provides the safety orientation training.


As part of worker qualification procedures, all off system crew leaders shall be provided a LKE Safety Passport Orientation Handbook (see Appendix 4.A) before being assigned work. Additionally, all off system workers must complete an Emergency Information Form, which is included in the Handbook.

The designated Safety Specialist or an alternative Company representative shall be responsible for reviewing the Handbook with off system workers and answering any related questions. In the event an off system worker identifies a LKE safety policy (such as PPE requirements) which differs or exceeds their Company’s safety policy, the responsible Safety Specialist shall review the policy difference with the designated Safety Officer.

The Safety Officer shall be responsible for developing and maintaining the Safety Passport Orientation Handbook to assure its contents align with Company safety policies and philosophies.

4.1.2. Passporting Video

As part of worker qualification procedures, all off system workers shall be required to witness the Company’s Safety Passport video for Electric Distribution and Transmission. Safety Specialist shall maintain copies of the passport video to be utilized as needed throughout the LG&E and KU service areas.
The Safety Officer shall be responsible for developing and maintaining the Emergency Restoration Safety Passporting video to assure its contents align with Company safety policies and philosophies.

4.1.3. **Passport Bracelets**

All off system workers who have submitted an Emergency Information Form, viewed the Safety Passport video, and reviewed the Safety Passport Orientation Handbook shall be provided and required to wear a Company assigned and sequentially numbered wrist band. The wrist band shall serve to provide field personnel the ability to visually determine if a field worker has obtained the necessary passport training when/if witnessed in the field working.
4.2. Independent Hold Card Procedures

During significant events on the Electric Distribution system, when large volumes of outage events and resource levels inundate Restoration Coordinators and saturate dedicated radio channels, the Distribution Control Center (DCC) and Operations Sections (OS) may elect to transfer control of all aspects of energy isolation and control procedures to qualified and approved personnel working on (operating, maintenance, repair, and construction) the electric distribution system.

The LG&E and KU Energy LLC, Lock Out/Tag Out (LOTO) Carding and Clearance Program for Electric Transmission, Distribution, and Substation, Version – 12/16/2013, establishes:

- Minimum requirements for transferring authority from the DCC to the OS;
- Documentation/record keeping requirements for field personnel; and
- Management’s communications responsibilities to assure all personnel involved in the energy isolation and control process are aware of the transition to independent hold card procedures.

The Manager DCC shall be responsible for notifying the Operations Section Chiefs and Incident Commander when field resource volumes exceed the capabilities of available Restoration Coordinators to efficiently utilize field resources. The Operations Section Chief shall be responsible for coordinating with local Operations Directors to determine if Independent Hold Card Procedures can be invoked. Upon receiving confirmation from the Operations Director and approval from the Safety Officer and Incident Commander, Independent Hold Card Procedures shall be executed. (Please see Appendix 4.B for a copy of the Company’s Independent Hold Card Procedures.)
5. Emergency Communications

**Purpose**
The purpose of EPRP Section 5.0 is to outline incremental internal and external communications procedures and organization setup which may be utilized by the Company during responses to emergencies, disasters, or weather events which result in significant damages and customer outages on Company electric distribution facilities.

**Scope**
The scope of EPRP Section 5.0 covers the Company’s electric distribution service territory, and all personnel, business partners and off system resources utilized in response to emergencies or significant outage events on the LG&E, KU, or ODP electric distribution system.

**Responsibilities**
The Information Officer shall have responsibility for assuring all resources available and assigned to assist with an emergency or significant restoration event are aware and knowledgeable of all Corporate Communications emergency policies and procedures.

**Training and Qualification**
The Information Officer and Incident Commander shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. *(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)*

**References**
None

**Revisions**
None
5.1 Internal Communications

All Sections of the Company’s Incident Command System shall have responsibility for ensuring timely, accurate, and consistent communications in preparation for and response to significant outage events and emergencies involving the electric distribution system.

5.1.1 Roles and Responsibilities

5.1.1.1 Incident Commander – or their designee shall be responsible for:

5.1.1.1.1 Maintaining a constant and direct line of contact with Command Staff and Information Officer, to ensure accurate and timely information exchange, and to review communications strategies and plans;

5.1.1.1.2 Communicating and working closely with the Emergency Preparedness and Response Team to ensure accurate and timely information is given to key internal and external stakeholders;

5.1.1.1.3 Serving as the primary communications representative on the Daily Outage Briefings and at the operations command center, if one has been established to manage the emergency response; and

5.1.1.1.4 Creating and submitting Executive Summary Reports.

5.1.2 Activation

5.1.2.1 Yellow Alert – The Incident Commander shall have responsibility for issuing Yellow Alerts, and notifying all Command Staff personnel. Whenever a Yellow Alert has been issued, the Command Staff and Section Chiefs or their designee shall have responsibility for executing assigned Yellow Alert tasks lists and associated emergency plans which address internal communications.

Under certain circumstances, the Incident Commander may need to execute emergency communications plans in advance of a Yellow Alert notification if internal information needs regarding a forecasted threat on the electric system cannot be satisfied utilizing day-to-day business processes.

5.1.2.1 Red Alert – The Incident Commander shall have responsibility for issuing Red Alerts, and notifying all Command Staff personnel. The Command Staff and Section Chiefs or their designee shall have overall responsibility for appropriately responding to Red Alert Levels issued by the Incident Commander or their designee, including
communicating to appropriate key leadership roles, and being available to assist with developing communications strategies and plans as needed to support the Company’s response to significant events, and to fulfill the information requirements of key internal stakeholders.

5.1.3 Business Processes

5.1.3.1 Internal Outage Communications Tool - The Internal Outage Communications (IOC) is a suite of dashboards, reports, extractable data, and maps available for key Company personnel to view, analyze, and react to outage data. The system displays outage, wires down, priority customer, and estimated restoration time information, filterable by Network Management System (NMS) Control Zone. The system also provides key resource data from the Resource on Demand (RoD) resource management application.

5.1.3.2 Daily Outage Briefings – Outage briefings shall be held daily, normally in the morning, to review the current system status and restoration progress, safety and/or operational issues, current day work plans, and resource, material, and logistic needs. Briefings should be short and concise, but should cover whatever site specific information is needed to assure effective, timely, and safe response to emergencies and significant outages, including:

- Safety Status and Considerations
- Active outage counts
- Active wire down counts
- Restored outage totals
- Covered wire down totals
- Weather Forecast
- Critical and Key Customer Outages
- Key External Communications
- Call Volumes
- Resource Needs
- Off-System Support Status/Timing
- Supplies and Logistics Status and Needs
- Facility and Staging Area Status and Needs

5.1.3.3 Executive Summary Reports – The Incident Commander, or their delegate, shall be responsible for providing senior management with routine Executive Summary
5.1.4 Training and Qualifications

The Emergency Preparedness and Response Team shall be responsible for ensuring all Company personnel and business partners assigned key emergency preparedness and response roles are trained on the Company’s Incident Command System and all critical communications systems, processes, and hierarchies.
5.2 External Communications

Corporate Communications shall have responsibility for working with the Emergency Preparedness, Planning, and Response Team to establish, test, and execute business procedures which provide timely, accurate, and consistent communications to customers and key stakeholders in preparation for or response to significant outage events and emergencies involving the electric distribution system.

5.2.1 Roles and Responsibilities

5.2.1.1 Information Officer –

5.2.1.1.1 Maintaining a constant and direct line of contact with designated Officers, General Counsel, and PPL Corporation (where appropriate), to ensure accurate and timely information exchange, and to review communications strategies and plans;

5.2.1.1.2 Communicating and working closely with the Incident Commander and Emergency Preparedness and Response Team to ensure accurate and timely information is given to key internal and external stakeholders;

5.2.1.1.3 Serving as the primary communications representative at the corporate command center, if one has been established to manage the emergency response;

5.2.1.1.4 Maintaining a direct line of communication with the On-Call Communications Representative to assess external communications needs and media coverage, and providing associated information to top management to assist them in communications decisions relating to the emergency;

5.2.1.1.5 Functioning as an official Company spokesperson, and if necessary, working with the appropriate Officers and Senior Managers if an alternative Company representative is elected to brief external stakeholders;

5.2.1.1.6 Overseeing the development and maintenance of standard communications templates and wording for various emergency types, to assure timely, effective, and efficient critical information provision to customers and key external stakeholders during significant emergencies and outage events;

5.2.1.1.7 Coordinating consistent information provision to state, regional, and local leaders and emergency management agencies through constant communications with key Customer Experience roles, including the Emergency Management Outreach and Critical Customer Directors in the Incident Command System.
5.2.1.2 Information Center Coordinator – responsible for:

5.2.1.2.1 Collaborating with the Incident Commander or their designee and drafting media information regarding system and outage status for review and approval by the Information Officer, before dissemination to media outlets;

5.2.1.2.2 Alerting other Communications Department staff members, using a departmental phone list to notify members outside of regular work hours, who can help in answering news media calls and in compiling appropriate background information and visuals that may be needed in responding to the media.

5.2.1.2.3 Making staff assignments to manage the preparation of media releases, compiling relevant background information, updating the company website as appropriate, monitoring and responding across social media channels, monitoring print and broadcast news coverage of the story, responding to the media telephone inquiries and requests for interviews.

5.2.1.2.4 Coordinating the drafting of media information for review and approval by the Information Officer and distributing it following approval.

5.2.1.2.5 Utilizing local and statewide media distribution lists, LG&E and KU’s Internet home page, and PPL’s corporate website as distribution vehicles.

5.2.1.2.6 Coordinating with Internal Communications to ensure the information is distributed simultaneously to all other LG&E and KU offices and divisions.

5.2.1.2.7 Coordinate the recording of relative message on media lines; and update when appropriate.

5.2.1.2.8 Keeping the Information Officer informed of interview requests as well as breaking news coverage.

5.2.1.2.9 Serving as a designated spokesperson for the company in responding to the media phone calls, especially in providing radio news interviews.

5.2.1.2.10 Managing the documentation of all news coverage as well as the recording and prompt transcription of any news media briefing or one-on-one interviews.

5.2.1.3 On-Call Communications Representative – responsible for,

5.2.1.3.1 Monitoring the Internal Notification Line and responding to notifications and inquiries regarding an outage event or emergency;

5.2.1.3.2 Establishing contact with the Incident Commander or designated Operations Management personnel to gather as much information as possible;
5.2.1.3.3 Assessing the severity level of an event to determine if other members of the Communications staff are needed to assist with managing internal and external information exchanges;

5.2.1.3.4 Executing call-out procedures for incremental Communications resources, as deemed necessary;

5.2.1.3.5 Serving as the initial spokesperson for the Company in responding to media inquiries about an emergency.

5.2.1.3.6 Providing Customer Service On-Call Supervision with information collected and provided externally to ensure consistency in messages being delivered to customers through various channels;

5.2.1.3.7 Keeping the Information Officer advised of any new developments and generally serving as a key source of information in making decisions on how to communicate during the crisis;

5.2.1.3.8 Providing the Information Officer, the Information Center Coordinator, and Communications Department staff members with relevant information for the development of written updates that will be provided to the media, customers (Customer Service and other customer-facing departments, as well as postings on the Company’s website and social media) and employees (via e-mails and/or Intranet site updates) whenever significant or new information is confirmed.

5.2.2 Activation

5.2.2.1 Yellow Alert – The Incident Commander shall have responsibility for issuing Yellow Alerts, and notifying all Command Staff personnel. Whenever a Yellow Alert has been issued, the Information Officer or their designee shall have responsibility for executing assigned Yellow Alert tasks lists and associated emergency plans which address external communications.

Under certain circumstances, the Information Officer may need to execute emergency communications plans in advance of a Yellow Alert notification if external information needs regarding a forecasted threat on the electric system cannot be satisfied utilizing day-to-day business processes.

5.2.2.2 Red Alert – The Incident Commander shall have responsibility for issuing Red Alerts, and notifying all Command Staff personnel. The Information Officer or their designee shall have overall responsibility for appropriately responding to Red Alert
Levels issued by the Incident Commander or their designee, including communicating to appropriate key leadership roles, and being available to assist with developing communications strategies and plans as needed to support the Company’s response to significant events, and to fulfill the information requirements of customers and other key external stakeholders.

5.2.3 Business Processes

5.2.3.1 Incident Notification - Company personnel who become aware of an emergency situation that is likely to generate news media interest should contact the Communications Department on LG&E and KU’s 24-hour Internal Notification Line (see Appendix 10). Communications retains an On-Call Communications Representative 24/7 to respond to Communications issues. The On-Call Communications Representative shall be responsible for evaluating the nature and scope of the emergency situation, and determine the breadth of coverage needed from Corporate Communications to adequately respond to external requests and need for information.

5.2.3.2 Level II-IV Events – If an emergency appears to be Level II-IV, the On-Call Communications Representative should contact the designated Information Officer. The Information Officer shall be responsible for keeping designated Executive Officers and General Counsel apprised of emergency situations and associated communications.

As designated by the Information Officer, a Communications representative should be assigned responsibility for communicating and working closely with the Incident Commander and Emergency Preparedness and Response Team to ensure accurate, timely, and consistent information exchanges occur with key internal and external stakeholders.

5.2.3.3 Media Updates – Whenever an emergency status or outage restoration update is provided to media outlets, the Information Officer should ensure a Communications Representative alerts Customer Service (Customer Experience Section) of all information provided to the news media, to ensure consistent information is being delivered to customers through various channels.

5.2.4 Training and Qualifications
The Information Officer shall be responsible for ensuring all Corporate Communications personnel are appropriately trained on external communications procedures in support of Company responses to significant outage events or emergencies involving the electric system.
5.3 Yellow and Red Alert Conference Calls

The purpose of this document is to provide conference call guidelines and protocol for preparedness and response efforts when a Yellow or Red Alert Level has been declared. The primary objective of conference calls shall be to provide an efficient forum for an exchange of information that enables safe, timely and cost-effective response to forecasted or actual threats.

5.3.1 Conference Call Initiation

5.3.1.1 Yellow Alert – The Incident Commander or their delegate shall have responsibility for initiating a conference call with the Emergency Preparedness and Response Team whenever a Yellow Alert has been declared and the possibility of a Level III or Level IV has been forecasted for the LG&E and KU electric service areas. The call should be scheduled sufficiently in advance of a forecasted event to allow Yellow or Red Alert task lists to be effectively executed.

5.3.1.2 Red Alert - The Incident Commander or their delegate shall have responsibility for initiating a conference call with the Emergency Preparedness and Response Team whenever a Red Alert has been declared for the LG&E and KU electric service areas, and a Level III or Level IV event has been experienced. Conference calls should be conducted at least twice daily throughout the duration of the restoration effort, or until the majority of customers have been restored. Every effort should be made to avoid scheduling calls during peak resource mobilization, customer communications, and work assignment periods.

5.3.2 Conference Call Guidelines

The Incident Commander or their delegate shall be responsible for moderating all Emergency Preparedness and Response Team conference calls. Additionally, the Incident Commander shall be responsible for designating note taker(s), prior to starting the conference call.

At the start of the conference call, the call moderator shall take role call to ensure all key areas of the Incident Command System are adequately represented on the call. If an area is not represented, the Incident Commander or their delegate shall be responsible for following up with those key roles as needed to exchange information with unrepresented areas.
Appendix 5.A contains a copy of the LG&E KU Emergency Preparedness and Response Conference Call Matrix and Call Checklists which should be utilized during conference calls to assure adequate information exchange occurs to effectively initiate and execute all appropriate alert level tasks and other needed response efforts.
6. Operations Section

**Purpose**
EPRP Section 6.0 introduces the high level organizational structure, roles, and associated responsibilities for the Operations Section of the Company’s Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

**Scope**
EPRP Section 6.0 and its Subsections cover all resources assigned to the Operations Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 6.1.

**Responsibilities**
The Operations Section of the Incident Command structure has overall responsibility for effectively managing available resources, developing and implementing plans for responding to system outages and damages, and protecting the public from damaged energy sources as described in EPRP Sections 6.0 – 6.5.
The Operations Chief has overall responsibility for overseeing and coordinating restoration and repair responses; assuring effective and efficient utilization of available resources; identifying resource needs and restoration projections based on those needs; and overseeing key roles identified in the subsections of 6.0 Operations Section.

The Emergency Preparedness and Response Team shall be responsible for developing Alert Level Task lists for all critical roles and functions under the Operations Section. (Please see Appendix 3.B.)

Training and Qualification
The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. (Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)

References
1. Louisville Gas and Electric Company, Terms and Conditions for Furnishing Electric Service; as filed with the Kentucky Public Service Commission; P.S.C. No. 9.
2. Kentucky Utilities Company; Rate, Terms, and Conditions for Furnishing Electric Service; as filed with the Kentucky Public Service Commission; P.S.C. No. 16.
3. Old Dominion Power Company, Terms and Conditions for Furnishing Electric Service; as filed with the Virginia State Corporation Commission; S.C.C. No. 15

Revisions
None
6.1. Resource Management

Electric Distribution Operations has developed Resource Management business processes for preparing for and responding to significant emergencies or outage events on the electric system. The primary focus of the organization during significant outage events and related emergencies is to effectively and efficiently manage and direct resources to:

- Protect the public from downed wires and damaged equipment;
- Safely restore service as quickly as possible; and,
- Repair or replace damaged facilities.

The procedures, roles, and responsibilities described herein are designed around Level III and IV events, but are scalable and transferable to all categories of events.

(Appendix 10 contains contact information for key Electric Distribution Operations personnel.)

6.1.1. Roles and Responsibilities

6.1.1.1. Operations Manager (OM) - or their designee, reports to the Operations Section Chief, and shall be responsible for:

6.1.1.1.1. Labor Resources - Identifying, coordinating, and managing labor resource requirements, including Line Technicians, Vegetation Management personnel, Public Safety Team members, Damage Assessors, and Resource Management personnel.

6.1.1.1.2. Restoration and Repair Planning – working with the Distribution Control Center (DCC) to develop and execute tactical responses to emergencies, including public safety, restoration prioritization, critical customer identification, work assignment, and resource allocation.

6.1.1.1.3. Restoration Durations – working with field personnel and Work Planning to predict restoration durations for areas of responsibility, assessing system damages against resources, and developing communications methodology which assure times are accurately and effectively communicated to internal and external customers.

6.1.1.1.4. The Operations Manager shall have oversight of all other roles listed under this section.

6.1.1.1.5. Vegetation Management Resource Leader (VMRL) or their designee, shall be responsible for:

6.1.1.1.5.1. Resources – the VMRL shall be responsible for working with the Operations Managers to equitably and effectively allocate and utilize vegetation management resources during restoration responses.
6.1.1.5.2. Tactical Planning – the VMRL shall also be responsible for working with the Operations Manager to develop plans for removing vegetation which inhibits restoration, including trimming circuits before resources are available, supplementing large crews with dedicated resources, and conducting post repair cleanup on damaged circuits.

6.1.1.6. Work Prioritization Leader (WPL) - or their designee, shall be activated when the DCC decentralizes work prioritization and assignment to the Operations Center, and be responsible for:

6.1.1.6.1. Work Prioritization – developing circuit and outage restoration and repair priorities based on 911 calls, emergencies, critical customers, key customers, and total customer counts, in accordance with restoration procedures covered in the Company’s tariffs.

6.1.1.6.2. Critical Customer Coordinator – responsible for staying abreast of critical customers impacted by system outages, and utilizing this information to help the WPL prioritize restoration and repair. This includes utilizing available information systems and reports, working with Major Accounts Representatives, the Ombudsman Team, and DCC to identify and prioritize critical customer issues that are out.

6.1.1.7. Work Assignment Coordinators - or their designee, shall be activated when the DCC decentralizes work prioritization and assignment to the Operations Center, and be responsible for:

6.1.1.7.1. Work Assignment – assigning bird dogs, line technicians, and vegetation management resources to outage events or circuits based on priorities established by the Work Prioritization Leader, and based on the capabilities and qualifications of available resources.

6.1.1.7.1.1. First Responders - working the DCC and Transmission Control Center (Simpsonville) to identify resource needs, including single-man and multiple-man truck first responders, and third shift resources, to dedicate to emergencies and necessary switching.

6.1.1.7.1.2. Public Works – assigning available and qualified resources to assist local governments with clearing streets and tree removal.

6.1.1.7.1.3. Bird Dogs – assigning qualified personnel to oversee/direct off system resources in the field and coordinate with the DCC.
6.1.1.7.2. Data Management – working with assigned Restoration Coordinators and Network Management Administrators to accurately track event and circuit assignments in the Network Management System, to ensure accurate restoration, outage, and system status information is available throughout the organization.

6.1.1.8. Safety Lead – or their designee, as assigned by the Safety Officer, shall be responsible for:
   6.1.1.8.1. Passporting – ensure that all internal and external personnel responding to emergencies or outage events are properly passported and administrated.
   6.1.1.8.2. Safety Oversight – work closely with the Operations Section Chief to resolve all safety issues associated with orientation and qualification of responding resources. Additionally, assist the Operations Section Chief with investigating all safety incidents.
   6.1.1.8.3. Safety Communications – work with the Operations Section Chief to assure timely reporting of safety messages, operations practices, policy changes, or safety incidents which occur throughout the duration of restoration efforts.

6.1.1.9. Administration Lead
   6.1.1.9.1. Work Assignment Administration – track circuit assignments to birddogs and line technicians resources;
   6.1.1.9.2. Hot Line – answer phones dedicated to the provision of resources to field personnel, including safety, tree trimming personnel, materials, traffic control, locates, and security.
   6.1.1.9.3. Completed Work Packets – working with bird dogs and foreman to ensure all field paperwork is properly completed upon completion of restoration and repair work, and return of work packets to the Resource Management Room/Operations Center.

6.1.1.9.4. Network Management System(NMS) Administrator
   6.1.1.9.4.1. Estimated Restoration Durations – utilize the Storm Management Tool to update OMS with estimated restoration times.
6.1.2. Activation

6.1.2.1. Yellow Alert – The Operations Section Chief, Incident Commander, or Operations Manager or their delegates shall have the authority to direct activation of Operations Management processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of Operations Management processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to manage incremental resources, prioritize emergencies, and assign first responders, damage assessors, and public safety response personnel.

6.1.2.2. Red Alert - The Work Planning Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have responsibility for activation of Resource Planning whenever a Red Alert has been declared, and the event has been established as Level III or IV for any Operations area.

6.1.3. Business Processes

6.1.3.1. Resource Processing
The Resource Management Team is responsible for ensuring all resources available to respond to an emergency are effectively and efficiently utilized. Every effort shall be made to minimize resource processing and work assignment time, and maximizing the time resources are in the field. This includes:

- Efficient check-in and check-out processing;
- Efficient birddog, materials, and vegetation resource allocation processes;
- Efficient work assignment processes;
- Establishment of centralized communications and provision of radios (as needed) to facilitate efficient communications exchanges regarding resource needs;
- Delivery of materials, meals, equipment, etc...to field crews to prevent them from having to leave the field; and,
• Provision of traffic control and security, to help minimize risks to the public and field personnel.

Electric Distribution has established a scalable and transferable Resource Management Room floor plan for managing Level III or IV events, where multiple off system resources are needed, and work prioritization and assignment responsibilities have been delegated by the DCC to an Operations Center. This floor plan allows for personnel and resources to be allocated from other operating areas to quickly and efficiently assist with managing work and resource volumes which exceed the capabilities of the local management team to manage. Appendix 6.A displays Electric Distributions’ configuration guideline for Resource Management command centers for Level III and Level IV events.

6.1.3.2. Work Prioritization

The Company shall prioritize and restore outages based on applicable Service Restoration Procedures as defined in the LG&E and KU Rates, Terms, and Conditions for Furnishing Electric Service as filed with the Kentucky Public Service Commission, Virginia State Corporation Commission, and Tennessee Regulatory Authority.

Restoration Priority Levels shall be defined as follows:

I. Essential Health and Safety Uses
II. Critical Commercial and Industrial Uses
III. Residential Use
IV. Non-critical Commercial and Industrial Uses
V. Nonessential Uses

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through IV as defined under these Priority Levels. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population of customers.

The Distribution Control Center shall have responsibility for prioritizing and assigning emergency and outage events to field personnel. During Level III and IV events, the Distribution Control Center may delegate work prioritization to an Operations Center, when multiple off system resources are being utilized, and work
6.1.3.3. **Work Assignment**

During Level III and IV events, the Distribution Control Center may also delegate work assignment responsibilities to an Operation Center(s). Operations Centers that have delegated work prioritization and assignment responsibilities shall designate an individual(s) to effectively assign event priorities with available resources, as part of the Resource Management process. Work assignment responsibilities shall include aligning available bird dogs, line technicians, and vegetation management with active outage events or circuits based on the capabilities and qualifications of available resources.

6.1.3.4. **Critical Customer Coordination**

During Level III and IV events, each Resource Management Team shall be responsible for designating a Critical Customer Coordinator(s) to assist with Work Prioritization. Assigned CCC’s shall be responsible for coordinating with Major Accounts Representatives, the Ombudsman Team, and the DCC to identify and prioritize critical customers that are impacted by system outages and to communicate pertinent information to individuals assigned responsibility for work prioritization.

6.1.4. **Training and Qualifications**

Operations Managers shall be responsible for ensuring all personnel assigned to Resource Management roles described herein are adequately trained and exposed to necessary business processes, alert level task lists, and information systems.
6.2. Distribution Control Center

The Distribution Control Center (DCC) coordinates and directs the system restoration with the Operations Center and acts as the Electric Distribution System Operator. The goals of the DCC team are:

- To maintain safety of public and field resources and integrity of electric distribution system.
- To safely, efficiently, and timely restore service to affected customers.
- To provide timely and accurate information on outages, estimated restoration times, etc. to be communicated to customers.

6.2.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.2.1.1. Distribution Control Center Manager – (Manager Electric System Restoration and Distribution) or their designee, shall be responsible for managing and overseeing operations and control of the Electric Distribution System:

6.2.1.1.1. Resources – establish schedules to ensure maximum coverage by Restoration Coordinators in all areas for all shift periods.

6.2.1.1.2. Activation - work with the PSRT Manager and Operations Manager to activate the PSRT and Damage Assessment.

6.2.1.1.3. Execution – monitor the operations of the DCC; decentralize dispatch functions when work and resource volumes dictate, and coordinate with Operations Section Chiefs, Incident Commander and Safety Officer to invoke Independent Hold Card Procedures when work and resource volumes dictate (see Section 4.2 Independent Hold Card Procedures).

6.2.1.1.4. Reports – report critical outage data both internally and externally as required.

6.2.1.1.5. Training – ensure all DCC personnel and Assistant Restoration Coordinators are trained in system restoration processes.

6.2.1.1.6. Deactivation – ensure a deactivation plan is in place for PSRT, Damage Assessment, and the DCC

6.2.1.2. DCC Responsibilities

6.2.1.2.1. Dispatch – assure timely dispatching of events from the NMS system.

6.2.1.2.2. System Operation – assure safe operation and integrity of electric distribution system is maintained at all times.
6.2.1.2.3. Restoration – assure safe, efficient restoration of outages through proper prioritization, identification of damages to distribution facilities, and control and direction of personnel to make the system safe and restore as many customers as possible, before repairs are made.

6.2.1.2.4. Switching/Carding – oversee safe and efficient control of the distribution system to facilitate the safest, quickest restoration.

6.2.1.2.5. Communication - assure timely and accurate outage information is gathered for communicating both internally and externally.

6.2.2. Activation

6.2.2.1. Yellow Alert – The Operations Section Chief, Incident Commander, or Distribution Control Center Manager or their delegates shall have the authority to direct activation of Distribution Control Center processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of DCC processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to manage incremental resources, prioritize emergencies, and assign first responders, damage assessors, and public safety response personnel.

6.2.2.2. Red Alert - The Operations Section Chief, Incident Commander, or Distribution Control Center Manager or their delegates shall have the authority to direct activation of Distribution Control Center processes whenever a Red Alert has been declared.

6.2.3. Training and Qualifications

6.2.3.1. The Distribution Control Center Manager shall be responsible for ensuring all personnel assigned to Distribution Control Center roles described herein are adequately trained and exposed to necessary business processes, alert level task lists, and information systems.
6.3. Public Safety Response Team (PSRT)

Electric Distribution has developed business processes (see Appendix 6.8) designed to help protect the public during weather events. The Public Safety Response Team has responsibility for overseeing and performing as first responders to ‘wire down’ calls. The goals of the PSRT team are to:

- Protect the public from potential hazards associated with downed power lines following major weather events;
- Relieve Fire and Police personnel assigned to wire down calls by County dispatch; and
- Gather damage assessment information in the field.

6.3.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.3.1.1. PSRT Manager or their designee, shall be responsible for overseeing the PSRT, its key roles, and PSRT functions consisting of the following:

6.3.1.1.1. Training – ensure that all wire walkers, wire sitters, service crews and damage assessors are trained. Additionally conduct refresher training for PSRT and DA dispatch teams (Lexington and Louisville) scheduled for on-call.

6.3.1.1.2. Activation – activate dispatch and field teams and ensure appropriate tracking of these resources is in place as directed by the Distribution Control Center Manager, Safety Officer, or Incident Commander.

6.3.1.1.3. Execution – monitor execution of wire down coverage and damage assessment, determine if additional resources are needed, and ensure shift rotations are established

6.3.1.1.4. Deactivation – support the DCC on clean-up, re-hooks with service crews, and deactivate field and back-office personnel as volume decreases.

6.3.1.2. LGE and KU PSRT Leaders – or their designee, shall be responsible for:

6.3.1.2.1. Process and Software Changes – review processes and make enhancements to ensure more efficient operations. Work with DCC on software changes that impact dispatcher interaction.

6.3.1.2.2. Training – conduct training sessions for all PSRT participants and ensure documentation and job aids are current. Track training history in a central repository.

6.3.1.2.3. Activation – establish callout procedures, contact lists, and schedules for dispatcher teams. Identify supervisors and managers that are required to assist in identifying field personnel for walking and sitting.

6.3.1.2.4. Execution –
6.3.1.2.4.1. Ensure proper dispatcher resources are available for storm event along with the proper number of field personnel.

6.3.1.2.4.2. Utilize a resource team to track all resources and establish appropriate shifts for multi-day events.

6.3.1.2.4.3. Support PSRT Dispatchers by responding to questions and issues that arise in the field.

6.3.1.2.4.4. Monitor Dispatcher performance and ensure proper procedures are being followed.

6.3.1.2.5. Deactivation – ensure a deactivation plan is in place and agreed to by the DCC. Ensure adequate resources are available to assist the DCC with clean-up work and re-hooks.

6.3.1.3. PSRT Dispatchers - shall be responsible for:

6.3.1.3.1. Dispatching Wire Walkers and/or Wire Sitters to wire down events.

6.3.1.3.2. Dispatching Service Crews to ‘cut and clear’ energized secondary/services where Wire Walkers and Wire Setters have been dispatched.

6.3.1.3.3. Utilizing proper prioritization for dispatching resources, specifically focusing on Police or Fire and energized conductor.

6.3.1.3.4. Utilizing PSRT processes and procedures to dispatch and update wire down events.

6.3.1.4. Wire Walkers - shall be able to clearly understand and identify electrical distribution infrastructure in the field to perform the following:

6.3.1.4.1. Function as ‘First Responder’ to wire down events dispatched by the Distribution Control Center (DCC) or PSRT.

6.3.1.4.2. Barricade appropriate area of damage to protect public and remain on site until relieved if dangerous situation exists (confirmed or potentially energized equipment).

6.3.1.4.3. Document damage assessment information from field via Mobile Application or communicate to PSRT Dispatcher verbally.

6.3.1.5. Wire Sitter - shall understand PSRT processes and procedures to perform the following:

6.3.1.5.1. Relieve Wire Walkers and remain at wire down location protecting the public until site is made safe.

6.3.1.5.2. Communicate any changes at the scene with PSRT Dispatch.
6.3.1.6. **Service Crew** - must be qualified to work with secondary and service conductors to perform the following:
- Relieve Wire Walkers and Wire Sitters from energized wire down events by ‘cutting and clearing’ or repairing the service.
- Communicate work performed at the wire down location and any follow up work to PSRT Dispatch.

6.3.2. **Activation**

6.3.2.1. **Yellow Alert** – The Safety Officer and Incident Commander or their delegates shall have the authority to direct activation of the PSRT whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of the PSRT shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and downed wires on the electric system.

6.3.2.2. **Red Alert** - The Distribution Control Center (DCC) Manager or their delegate shall have responsibility for activation of the PSRT whenever downed wire reports and field resources exceed the capabilities of Restoration Coordinator staffing levels in the Louisville or Lexington Distribution Control Centers. The Safety Officer and Incident Commander or their delegates shall also have the authority to direct activation of the PSRT whenever a Red Alert has been issued by the Incident Commander or their designee.

6.3.1. **Training and Qualification**

6.3.1.1. **PSRT Dispatchers** – PSRT teams are on call for two week periods, and serve as a backup team for the next two week period. PSRT Leads provide team members refresher training on the first Monday of their two week on call period.

Training consists of all aspects of the Network Management System program (work agenda, crew assignments, the viewer, damage assessment, etc.) and associated data entry procedures for dispatching to non-mobile and mobile enabled wire-walkers. The mobile training also includes sending wire-down events to mobile wire-walkers who are set up in a training room at EOC and AOC.

6.3.1.2. **Wire Walkers** – All Wire Walkers must attend a training and qualification course provided by the PSRT Lead(s).
Company or Contractor personnel must demonstrate a general knowledge of electric distribution infrastructure and characteristics to be considered for a Wire Walker position. Candidates typically have field experience in electric operations or design.

All new Wire Walkers must be paired with an experienced Wire-Walker prior to being allowed to perform wire walking duties without supervision or guidance. PSRT Leads are responsible for evaluating the knowledge and abilities of Wire Walkers to perform associated responsibilities without direction or oversight.

6.3.1.3. Wire Sitters – All Wire Sitters are required to receive training provided by the PSRT Lead. A driver’s license and proper PPE are the basic qualification requirements to be a wire-sitter. Most wire-sitters are pulled from LG&E Gas Operations, Asset Information, or from approved business partners.

6.3.1.4. Service Crews – All Business Partner Trainers are required to receive PSRT Service Crew training provided by the PSRT Lead and a Safety Specialist.

Service crews are typically pulled from qualified resident contractors (who may normally work in street lighting, underground and/or commercial electric) that have received the Company’s Safety Passport Training.
6.4. Damage Assessment (DA)

Electric Distribution has developed business processes (see Appendix 6.B) to gather damage assessment information from the field. The goals of the DA team are:

- To identify and prioritize areas of the system to be assessed.
- To gather damage assessment information in the field.
- To ensure damage information data is accumulated to provide to field resources and to allow evaluation and reporting of system impacts.

6.4.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.4.1.1. PSRT Manager or their designee, shall be responsible for overseeing the DA, its key roles, and DA functions consisting of the following:

6.4.1.1.1. Training – ensure that all damage assessors are trained. Additionally conduct refresher training for PSRT and DA dispatch teams (Lexington and Louisville) scheduled for on-call.

6.4.1.1.2. Activation – activate dispatch and field teams and ensure appropriate tracking of these resources is in place as directed by the Distribution Control Center Manager, Safety Officer, or Incident Commander.

6.4.1.1.3. Execution – monitor execution of damage assessment, determine if additional resources are needed, and ensure shift rotations are established.

6.4.1.1.4. Deactivation – support the DCC on clean-up and deactivate field and back-office personnel as volume decreases.

6.4.1.2. Assessment Leaders (AL) – or their designee, shall be responsible for:

6.4.1.2.1. Process and Software Changes – review processes and make enhancements to ensure more efficient operations. Work with DCC on software changes that impact dispatcher interaction.

6.4.1.2.2. Training – conduct training sessions for all DA participants and ensure documentation and job aids are current. Track training history in a central repository.

6.4.1.2.3. Activation – establish callout procedures and schedules for dispatcher teams. Identify supervisors and managers that are required to assist in identifying field personnel for assessing.

6.4.1.2.4. Execution –

6.4.1.2.4.1. Ensure adequate dispatch personnel and damage assessors are available for storm events.
6.4.1.2.4.2. Review system outages and work with Work Planning and the Work Prioritization Leader to identify circuits or parts of the system that need further damage assessment based on outages and resource availability.

6.4.1.2.4.3. Effectively track all resources and establish appropriate shift schedules for multi-day events.

6.4.1.2.4.4. Support DA Dispatchers by responding to questions and issues that arise in the field.

6.4.1.2.4.5. Monitor Dispatcher performance and ensure proper procedures are being followed.

6.4.1.2.5. Deactivation – ensure a deactivation plan is in place and agreed to by the DCC and Operations Section Chief.

6.4.1.2.6. Post Restoration Assessment - the Assessment Leader or their designee shall be responsible for reviewing system outages and working with the Work Planning Leader to identify circuits or parts of the system that need post restoration assessment based on outages and storm damages. The Assessment Leader shall work with the PSRT Leader, and Operations Manager to identify available resources for performing assessments.

6.4.1.3. Damage Assessment Coordinators – shall be responsible for:

6.4.1.3.1. Assuring adequate assessment resources are available.

6.4.1.3.2. Assigning assessment work based on established priorities.

6.4.1.3.3. Accumulating damage assessment data, and evaluating and reporting system impacts.

6.4.1.3.4. Working with Work Planning and the Resource Managers to predict resource needs and restoration durations.

6.4.1.4. Damage Assessment Dispatchers - shall be responsible for:

6.4.1.4.1. Dispatching Damage Assessors to identified areas needing assessment.

6.4.1.4.2. Utilizing proper prioritization for dispatching resources.

6.4.1.4.3. Utilizing DA processes and procedures to dispatch and update DA identified circuits/events.

6.4.1.5. Damage Assessors – shall be responsible for:

6.4.1.5.1. Conducting field assessments of assigned circuits/events.

6.4.1.5.2. Identifying and documenting system damage.
6.4.1.5.3. Working with Damage Assessment Coordinators to help predict resource (personnel, equipment, and materials) needs and estimated restoration durations.

6.4.2. Activation

6.4.2.1. Yellow Alert – The Operations Section Chief and Incident Commander or their delegates shall have the authority to direct activation of Damage Assessment processes and teams whenever a Yellow Alert has been issued by the Incident Commander or their designee. Pre-staging of damage assessment teams and key roles shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and downed wires on the electric system.

6.4.2.2. Red Alert - The Incident Commander, Operations Section Chief, Distribution Control Center (DCC) Manager or their delegate shall have responsibility for activation of Damage Assessment processes whenever outage and field reports indicate significant infrastructure damage which exceeds the capabilities of available field resources.

6.4.1. Training

6.4.1.1. Damage Assessment Dispatchers – Dispatch teams are on call for two week periods, and serve as a backup team for the next two week period. Assessment Leads provide team members refresher training on the first Monday of their two week on call period.

Training consists of all aspects of the Network Management System program (work agenda, crew assignments, the viewer, damage assessment, etc.) and associated data entry procedures for dispatching damage assessment assignments to non-mobile and mobile enabled damage assessors.

6.4.1.2. Damage Assessors – All Damage Assessors must attend an annual training and qualification course provided by Assessment Lead(s).

Company or Contractor personnel must demonstrate a general knowledge of electric distribution infrastructure and characteristics to be considered for a Damage Assessor position. Candidates typically have field experience in electric operations or design.
All new Damage Assessors must be paired with an experienced Damage Assessor prior to being allowed to perform assessment duties without supervision or guidance. Assessment Leads are responsible for evaluating the knowledge and abilities of Damage Assessors to perform associated responsibilities without direction or oversight.
6.5. Transmission Operations

Transmission Operations assesses the impact to the system and coordinates and directs the restoration of the transmission system. The goals of the Transmission Operations team are:

- To maintain safety of public and field resources and integrity of electric transmission system.
- To safely, efficiently, and timely restore service to affected customers.
- To provide timely and accurate information on outages, estimated restoration times, etc. to be communicated to customers.

6.5.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.5.1.1. Transmission Operations Lines Manager – or their designee, reports to the Transmission Operations Section Chief, and shall be responsible for:

6.5.1.1.1. Labor Resources - Identifying, coordinating, and managing labor resource requirements, including Line Technicians, Vegetation Management personnel, Damage Assessors, and Resource Management personnel.

6.5.1.1.2. Restoration and Repair Planning – working with the Transmission Control Center (TCC) to develop and execute tactical responses to emergencies, including public safety, restoration prioritization, critical customer identification, work assignment, and resource allocation.

6.5.1.1.3. Restoration Durations – working with field personnel and TCC to predict restoration durations for areas of responsibility, assessing system damages against resources, and developing communications methodology which assure times are accurately and effectively communicated to internal and external customers.

6.5.1.1.4. The Transmission Operations Lines Manager shall have oversight of all other roles listed under this section.

6.5.1.2. Transmission Control Center Manager – or their designee, shall be responsible for managing and overseeing operations and control of the Electric Transmission System:

6.5.1.2.1. Resources – establish schedules to ensure maximum coverage by System Operators in all areas for all shift periods.

6.5.1.2.2. Activation - work with the Transmission Operations Lines Manager to activate assessment personnel.
6.5.1.2.3. Execution – monitor the operations of the TCC and coordinate system restoration with Transmission Operations Lines Manager and Section Chief and Incident Commander.

6.5.1.2.4. Reports – report critical outage data both internally and externally as required.

6.5.1.2.5. Training – ensure all TCC personnel are trained in system restoration processes.

6.5.1.2.6. Deactivation – ensure a deactivation plan is in place for the TCC.

6.5.1.3. Transmission Control Center Responsibilities

6.5.1.3.1. System Operation – assure safe operation and integrity of electric transmission system is maintained at all times.

6.5.1.3.2. Restoration – assure safe, efficient restoration of outages through proper prioritization, identification of damages to transmission facilities, and control and direction of personnel to make the system safe and restoration efficient.

6.5.1.3.3. Switching/Carding – oversee safe and efficient control of the transmission system to facilitate the safest, quickest restoration.

6.5.1.3.4. Communication - assure timely and accurate outage information is gathered for communicating both internally and externally.

6.5.2. Activation

6.5.2.1. Yellow Alert – The Transmission Operations Section Chief, Incident Commander, or Transmission Control Center Manager or their delegates shall have the authority to direct activation of the Transmission Operations processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of these processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to manage incremental resources, prioritize emergencies, and assign first responders.

6.5.2.2. Red Alert - The Transmission Operations Section Chief, Incident Commander, or Transmission Control Center Manager or their delegates shall have the authority to
direct activation of Transmission Operations Emergency Plan processes whenever a Red Alert has been declared.

6.5.3. Transmission Alert Levels

6.5.3.1. Transmission Alert Level Declarations - Alert level declaration is normally post event and is based on the assessment of the potential impact to the LGE-KU Transmission System. The Transmission Operations Lines Manager or his designee will declare the transmission event alert level.

Conditions that could warrant declaring an alert level may include but are not limited to:

- Weather related conditions such as severe thunderstorms, intense lightning storms, tornadoes, ice/snow accumulation, high winds and flooding
- Loss of multiple transmission facilities
- Forest and brush fires
- Geomagnetic disturbances
- Any other event that may pose a threat or disruption to the bulk electric system

6.5.3.2. Transmission Alert Levels

6.5.3.2.1. Alert Level I - (Moderate Impact) It is anticipated that the pending event will have only a moderate impact to the LGE-KU Transmission System. Localized service territory outages occur.

6.5.3.2.2. Alert Level II - (Significant Impact) It is anticipated that the pending event will have a significant impact to the LGE-KU Transmission System. Multiple outages over a large portion of the LGE-KU service territory

6.5.3.2.3. Alert Level III - (Major Impact) It is anticipated that the pending event to have a major impact to the LGE-KU Transmission System. Wide spread outages with significant damage to the Bulk Electric System (BES) has occurred.

6.5.3.3. Transmission Alert Level Activities - The Alert Level declaration will trigger various actions within each line of business. Each line of business will have their own in house procedures in place to address the various Alert Levels and required actions.
6.5.3.4. Transmission Alert Level Communication - Communication of the Alert Levels to each line of business will be the responsibility of Transmission Control Center at Simpsonville. Email notification will be the primary source of communication.

6.5.3.4.1. Logging the Alert Level - Transmission control center will log the Alert Level along with start date and time in Transmission Outage Application (TOA). Transmission control center will notify each line of business of the Alert Level.

6.5.3.4.2. Changes to the Alert Level - Transmission control center will log any changes or modification to the Alert Level along with the start date and time in TOA. Transmission control center will notify each line of business of the change or modification of the Alert Level.

6.5.3.4.3. Return to Normal Operations - Transmission control center will log the “Return to Normal Operations” in TOA along with the date and time when the Alert Level has been canceled. Transmission control center will notify each line of business that the Alert Level has been canceled and is no longer active.

6.5.4. Training and Qualifications

6.5.4.1. The Transmission Operations Lines Manager and Transmission Control Center Manager shall be responsible for ensuring all personnel assigned to roles described herein are adequately trained and exposed to necessary business processes and information systems.
6.6. Estimated Restoration Times

The Emergency Preparedness and Response Team has developed business procedures for communicating estimated restoration times to customers during a significant event on the electric distribution system. The following table outlines EDO’s communications commitments and responsibilities.

<table>
<thead>
<tr>
<th>ERTs</th>
<th>Level I Event</th>
<th>Level II Event</th>
<th>Level III Event</th>
<th>Level IV Event</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>&lt; 6 hours</td>
<td>&lt; 24 hours</td>
<td>&lt; 72 hours</td>
<td>&gt; 72 hours</td>
</tr>
<tr>
<td><strong>Ops Center Level</strong></td>
<td>0 - 6 hours</td>
<td>0 - 8 hours</td>
<td>0 - 24 hours</td>
<td>0 - 48 hours</td>
</tr>
<tr>
<td>ERT Source</td>
<td>MSRD, MDO</td>
<td>MSRD, MDO</td>
<td>OSC, WPSC</td>
<td>OSC, WPSC</td>
</tr>
<tr>
<td>Update Responsibility</td>
<td>DCC</td>
<td>DCC</td>
<td>OS</td>
<td>OS</td>
</tr>
<tr>
<td><strong>Local Area Level</strong></td>
<td>0 - 6 hours</td>
<td>0 - 12 hours</td>
<td>24 - 36 hours</td>
<td>48 - 72 hours</td>
</tr>
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<td>MSRD, MDO</td>
<td>OSC, WPSC</td>
<td>OSC, WPSC</td>
</tr>
<tr>
<td>Update Responsibility</td>
<td>DCC</td>
<td>DCC</td>
<td>OS</td>
<td>OS</td>
</tr>
<tr>
<td><strong>Circuit Level</strong></td>
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<td>0 - 12 hours</td>
<td>24 - 36 hours</td>
<td>48 - 72 hours</td>
</tr>
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<td>MSRD, MDO</td>
<td>Birddog</td>
<td>Birddog</td>
</tr>
<tr>
<td>Update Responsibility</td>
<td>DCC</td>
<td>DCC</td>
<td>OS</td>
<td>OS</td>
</tr>
<tr>
<td><strong>Event Level</strong></td>
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<td>0 - 24 hours</td>
<td>0 - 72 hours</td>
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<td>Birddog, LT</td>
</tr>
<tr>
<td>Update Responsibility</td>
<td>DCC</td>
<td>DCC</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

**Definitions:**
- **Birddogs** - Team Leader or Supervisor assigned responsibility for circuit.
- **MSRD** - Manager System Restoration and Dispatch
- **LT** - Line Technicians
- **OSC** - Operations Section Chief (IC Structure)
- **MDO** - Manager Distribution Operations
- **WPSC** - Work Planning Section Chief (IC Structure)

**Table 1.** Estimated Restoration Communications Schedule

### 6.6.1. Level I Events

During Level I events, the Distribution Control Center (DCC) will be responsible for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures. The Public Safety Response Team (PSRT) will be activated as deemed appropriate by the Incident Commander, Operations Section Chief, and Manager System Restoration and Dispatch. Work Planning will not be activated.
The Estimated Restoration Time Editor (ERTE) tool in the Company’s outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

Field personnel/technicians shall be responsible for obtaining and updating estimated restoration times by Event through utilization of their mobile device, as events are assessed, resource needs are identified, and restoration durations are estimated. The Manager-System Restoration and Dispatch shall be responsible for ensuring Restoration Coordinators continuously monitor NMS to ensure Field Personnel are appropriately assigning ERTs.

As soon as attainable, but before 6 hours have elapsed, the responsible Operations Manager and Manager-System Restoration and Dispatch shall establish Operations Center Level Estimated Restoration Times, based on event level ERTs, consideration of resource levels, and input from field personnel.

6.6.2. Level II Events

During Level II Events, the Distribution Control Center will be responsible for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures. The Public Safety Response and Damage Assessment teams will be activated as deemed appropriate by the Incident Commander, Operations Section Chief, and Manager System Restoration and Dispatch. Work Planning will be activated with the PSRT, or as requested by the Incident Commander or DCC Director.

The Estimated Restoration Time Editor (ERTE) tool in the Company’s outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

Field personnel/technicians shall be responsible for obtaining and updating estimated restoration times by Event through utilization of their mobile device, as events are assessed, resource needs are identified, and restoration durations are estimated. The Manager-System Restoration and Dispatch shall be responsible for ensuring Restoration Coordinators continuously monitor NMS to ensure Field Personnel are appropriately assigning ERTs.
As soon as attainable, but before 8 hours have elapsed, the responsible Operations Manager and Manager-System Restoration and Dispatch shall establish Operations Center Level Estimated Restoration Times, based on event level ERTs, consideration of resource levels, and input from field supervision. Work Planning shall be responsible for posting the ERT to the Company’s Website. After the Operations Center Level ERTs are established, the DCC Restoration Coordinators shall continue to utilize NMS to update estimated restoration times by event, as field resources assess damages, estimate resource needs, and predict restoration durations.

### 6.6.3. Level III Events

During Level III events, the Distribution Control Center will maintain responsibility for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures until it is determined that restoration operations should be decentralized. PSRT and Work Planning will be activated. Each impacted Operations area will activate their Resource Management Rooms.

The Estimated Restoration Time Editor (ERTE) tool in the Company’s outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

When formally agreed upon by the responsible Manager-Distribution Operations and Manager-System Restoration and Dispatch, and approved by the Incident Commander, Safety Officer, and Operations Section Chief, the DCC shall decentralize responsibility for prioritizing and assigning outage events to the responsible Resource Management Rooms. The Resource Management Rooms will be responsible for obtaining ERT information on all system outages and impacted circuits using information obtained from Damage Assessment teams, Wire Walkers, first responders, and Bird Dogs.

As soon as attainable, but before 24 hours have elapsed, the Operations and Work Planning Section Chiefs shall establish Operations Center Level Estimated Restoration Times, based on ERT information obtained from the Resource Management Rooms, consideration of resource levels, and input from the Operations Managers and Manager System Restoration and Dispatch. Work Planning will be responsible for utilizing the NMS Storm Management Tool to enter Operations Center level ERTs into NMS, based on information received from field resources, consideration of resources levels, and input from the Operations Section Chief. As restoration efforts progress, the Resource
Management Rooms shall be responsible for assessing system damages, restoration progress, field resources, and material availability to develop more precise restoration predictions at local and circuit levels, in accordance with Table 1.

Throughout restoration events, the Resource Management Rooms shall update circuit level ERTs three times per day, or as work is completed or situations change. Work Planning and the Operations Section will be responsible for monitoring ERTs in NMS, to assure accuracy and thoroughness.

### 6.6.4. Level IV Events

During Level IV events, the Distribution Control Center will maintain responsibility for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures until it is determined that restoration operations should be decentralized. PSRT and Work Planning will be activated. Each impacted Operations area will activate their Resource Management Rooms.

The Estimated Restoration Time Editor (ERTE) tool in the Company’s outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

When formally agreed upon by the responsible Manager-Distribution Operations and Manager-System Restoration and Dispatch, and approved by the Incident Commander, Safety Officer, and Operations Section Chief, the DCC shall decentralize responsibility for prioritizing and assigning outage events to the responsible Resource Management Rooms. The Resource Management Rooms will be responsible for obtaining ERT information on all system outages and impacted circuits using information obtained from Damage Assessment teams, Wire Walkers, first responders, and Bird Dogs.

As soon as attainable, but before 48 hours have elapsed, the Operating and Work Planning Section Chiefs shall establish Operations Center Level Estimated Restoration Times, based on ERT information obtained from the Resource Management Rooms, consideration of resource levels, and input from the Operations Managers and Manager System Restoration and Dispatch. Work Planning will be responsible for utilizing the NMS Storm Management Tool to enter Operations Center level ERTs into NMS, based
on information received from field resources, consideration of resources levels, and input from the Operations Section Chief. As restoration efforts progress, the Resource Management Rooms shall be responsible for assessing system damages, restoration progress, field resources, and material availability to develop more precise restoration predictions at local and circuit levels, in accordance with Table 1.

Throughout restoration events, the Resource Management Rooms will be responsible for updating circuit level ERTs three times per day or as work is completed or situations change. Work Planning and the Operations Section will be responsible for monitoring ERTs in NMS, to assure accuracy and thoroughness.
6.7 Conservative Operations

Electric Distribution has developed criteria and procedures for implementing Conservative Operations when forecasted or actual weather conditions, system health, natural disasters, emergency situations, or other factors pose a threat to the operability, reliability, or integrity of the electric distribution system.

6.7.1 Roles and Responsibilities

6.7.1.1 Manager Electric System Restoration and Distribution, or their designee, shall be responsible for overseeing personnel assigned responsibility for monitoring the electric distribution system, and making determination if standard Conservative Operations procedures should be implemented. If Conservative Operations are declared, the following responsibilities should be executed:

6.7.1.1.1 Advise the Director Electric System Restoration and Distribution or their designee of the need to Declare Conservative Operations.
6.7.1.1.2 Define the boundaries of Conservative Operations.
6.7.1.1.3 Define the start and end times of Conservative Operations.

6.7.1.2 Provide routine updates to the affected Electric Distribution Operations management team.

6.7.1.3 Work with Information Technology’s designated representatives to suspend all work on critical computer systems, such as the Network Management System (NMS) and Mobile Applications.

6.7.1.4 Work with affected Operations Managers to identify and review all maintenance, construction, and testing being performed on electric distribution facilities and where appropriate, delaying or cancelling scheduled work. This includes non-essential planned maintenance, construction, operations, tree trimming, substation work, etc.

6.7.1.5 Assess the adequacy of Distribution Control Center staffing levels and make adjustments where necessary.

6.7.1.6 Work with the Incident Commander, Work Planning, and Operations Managers, where necessary, to review staffing plans/schedules for key technical and field personnel, and make adjustments where necessary.

6.7.1.2 Group Leader – Distribution Control Center, or their designee, shall be responsible for notifying the Manager Electric System Restoration and Distribution of any actual or forecasted conditions posing a threat to the operability, reliability, and safety of
the electric distribution, as reported by Restoration Coordinators under their responsibility.

6.7.1.3 **Restoration Coordinators** shall be responsible for continuously monitoring the electric distribution system and weather conditions to identify conditions which warrant implementation of Conservative Operations. Whenever prescribed threshold conditions are observed or are forecasted to occur, Restoration Coordinators shall advise the Group Leader – Distribution Control Center.

6.7.2 **Conservative Operations Criteria**

The following conditions shall justify consideration and declaration of Conservative Operations procedures to protect the reliability and integrity of the electric distribution system:

- **Extreme Temperatures**
  - Actual or Forecasted Temperatures below 15°F
  - Actual or Forecasted Temperatures above 95°F

- **Extreme Weather Conditions**
  - Actual or Forecasted Ice Accretion > 0.25”
  - Actual or Forecasted Snow Accumulation > 6”
  - Actual or Forecasted Wind Speeds > 45mph
  - Actual or Forecasted Severe Weather
  - Actual or Forecasted Flooding

- **System Health Threats**
  - Observed or predicted capacity concerns
  - Observed or predicted voltage concerns
  - Loss of key power generation, transmission, or distribution facilities

- **Emergencies**
  - Train Derailment
  - Fire
  - Chemical Spill or other Environmental Threat
  - Explosions
  - Civil unrest

- **Natural Disasters**
  - Earthquakes
The Manager Electric Restoration and Distribution has the authority to declare and implement Conservative Operations procedures whenever conditions are experienced which are not identified above but pose sufficient threat(s) to the Electric Distribution system.

### 6.7.3 Conservative Operations Procedures

The following procedures should be executed whenever the Manager Electric Restoration and Distribution declares that Conservative Operations are needed to protect the reliability and integrity of the electric distribution system. All affected operating areas’ personnel and business partners shall be notified of a Conservative Operations declaration. Where appropriate, the Manager Electric Restoration and Distribution and responsible Operations Manager, or their delegates, may elect to deviate from these procedures if risk concerns can be alleviated through alternative procedures.

#### 6.7.3.1 Cessation of Cautions

The following cessation of cautions shall apply for all substation circuit breakers and reclosers. Cessation of cautions for distribution line reclosers will be dependent on loading, customers served, weather conditions, etc. as determined by Distribution Control Center.

- **6.7.3.1.1** Cautions for planned work will not be issued whenever actual or forecasted temperatures are above 100°F.
- **6.7.3.1.2** Cautions for planned work on LG&E or KU Winter Peaking Substations will not be issued whenever actual or forecasted temperatures are below 15°F.
- **6.7.3.1.3** Cautions for planned work on LG&E or KU Summer Peaking Substations will not be issued whenever actual or forecasted temperatures are below 5°F.
- **6.7.3.1.4** Cautions for planned work will not be issued (for affected facilities) whenever severe weather, natural disasters, emergencies, system conditions, or other conditions pose a threat to the integrity and reliability of the electric distribution system.

#### 6.7.3.2 Cessation of Customer Pull-Offs

- **6.7.3.2.1** No customers should be pulled off for planned work whenever actual or forecasted temperatures are above 100°F.
6.7.3.2 No customers should be pulled off for planned work whenever actual or forecasted temperatures are below 10°F.

6.7.3.3 Limited Planned Customer Outage Durations
6.7.3.3.1 Planned customer outages will be allowed, but be limited in duration and customer counts whenever actual or forecasted temperatures are between 95°F and 100°F.
6.7.3.3.2 Planned customer outages will be allowed, but be limited in duration and customer counts whenever actual or forecasted temperatures are between 10°F and 15°F.

6.7.3.4 Cessation of Planned Construction, Maintenance, Testing, and Operations
6.7.3.4.1 Operations Management should give consideration to ceasing all planned construction, maintenance, testing, and operations on the electric distribution system whenever severe weather, natural disasters, emergencies, system conditions, or other conditions pose a threat to its integrity and reliability.
7. Customer Experience Section

**Purpose**
EPRP Section 7.0 introduces the high level organizational structure, roles, and associated responsibilities for the Customer Experience Section of the Company’s Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

**Scope**
EPRP Section 7.0 and its Subsections cover all resources assigned to the Customer Experience Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 7.1.

![Customer Experience Section Organization Diagram](image)

**Responsibilities**
The Customer Experience Section of the Incident Command structure has overall responsibility for developing and executing preparedness and response plans which focus on customers’ needs during responses to significant outage events or other emergencies on the electric distribution system.

**Training and Qualification**
The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. *(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)*
Electric Distribution
Emergency Preparedness and Response Plan

Section 7.0
Customer Experience Section

Effective Date: 9/30/2014

References
None

Revisions
None
7.1 Critical Customer Care

The Company’s Customer Experience Section of the Incident Command System shall have primary responsibility for ensuring adequate procedures are in place to identify and communicate with critical, key, and major customers during large outage events or emergencies involving the electric system.

7.1.1 Roles and Responsibilities (See Appendix 10 for key contact information)

7.1.1.1 Critical Customer Director – or their designee, shall report to the Customer Experience Section Chief and shall have responsibility for the following:

- Ensuring adequate resources, technology, and procedures are in place to identify and communicate with critical, key, major, and municipal customers during large outage events or emergencies involving the electric system;
- Ensuring adequate procedures are in place to communicate critical, key, major, and municipal customer information to internal stakeholders during large outage events or emergencies involving the electric system;
- Collaborating with the Customer Experience Section Chief to ensure consistent information is being communicated to customers, local authorities, emergency operations centers, and government entities;
- Verifying all available communications channels are working properly and allowing affected customers to identify outages and obtain restoration status information.

7.1.1.2 Major Account Representatives – shall be responsible for:

- Communicating with major account customers throughout restoration efforts to ensure timely and accurate outage and restoration information is available to assist them with making critical decisions; and
- Working with Critical Customer Coordinators and/or Work Prioritization Leads under the Operations Section to ensure Major Account customer information is considered when determining safety, restoration, and repair priorities.

7.1.1.3 Ombudsman Team Lead – shall be responsible for:

- Serving as customer communication channel for key accounts, schools, local politicians, etc. whom need critical outage restoration information and assistance during restoration activities; and
- Working with Critical Customer Coordinators and/or Work Prioritization Leads under the Operations Section to ensure key and critical customer
Electric Distribution
Emergency Preparedness and Response Plan

Section 7.1
Critical Customer Care

Effective Date: 9/30/2014

Version No. 1

information is considered when determining safety, restoration, and repair priorities.

7.1.1.4 Municipal Account Manager – shall be responsible for:

7.1.1.4.1 Coordinating with Operations to serve as a customer communication channel for municipal account customers who need critical outage restoration information and assistance during outage events and significant emergencies; and,

7.1.1.4.2 Working with Critical Customer Coordinators and/or Work Prioritization Leads under the Operations Section to ensure municipal customer information is considered when determining safety, restoration, and repair priorities.

7.1.2 Activation

7.1.2.1 Yellow Alert – The Customer Experience Section Chief or their delegate shall have authority for activating Customer Experience emergency business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Customer Experience business processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant electric system damages and customer outages. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to effectively respond to affected customer inquiries and reports when outages start occurring.

7.1.2.2 Red Alert - The Customer Experience Section Chief or their delegate shall have responsibility for activation of emergency Customer Experience business processes whenever a Red Alert has been declared and significant electric system damages and customer outages are occurring or expected to occur.

7.1.3 Business Processes

7.1.3.1 Major Accounts

During significant outage events, where multiple key and critical customers are impacted, Major Accounts Representatives shall be responsible for developing an understanding of their impacted customers through review of critical customer outage report, Web Work Agenda, or the Internal Outage Communications Tool.
Major Accounts Representatives with impacted customers shall be responsible for exchanging critical outage and restoration information with designated major account contacts and key internal Operations and Customer Service personnel.

During Level III and IV events, consideration should be given to strategically placing Major Accounts Representative in Resource Management Rooms to expedite the exchange of critical information regarding outages, restoration efforts, and estimated restoration times.

### 7.1.3.2 Ombudsman Team

During significant outage events, the Ombudsman Team will be established to coordinate and communicate with state, city, and county officials, company executives, Major Accounts Representatives, and the Emergency Planning and Preparedness Manager. Ombudsman Team shall be responsible for developing an understanding of their impacted customers through review of critical customer outage report, Web Work Agenda, or the Internal Outage Communications Tool.

Ombudsman Team shall be responsible for exchanging critical outage and restoration information with designated state, city, and county officials, Major Account Representatives and key internal Operations and Customer Service personnel.

During Level III and IV events, consideration should be given to strategically placing an Ombudsman Team member in Resource Management Rooms to expedite the exchange of critical information regarding outages, restoration efforts, and estimated restoration times.

### 7.1.3.3 Municipal Customer Outages

Designated Distribution and Transmission personnel (Designee) and the Municipal Account Manager are notified via text whenever a Municipal Customer experiences an outage. Upon receiving notification of a municipal outage, the Designee shall investigate and confirm the outage. Whenever a municipal outage is confirmed, the Municipal Account Manager shall contact affected municipal customers using the 24/7 Municipal Calling List, coordinate communications priorities with designated Municipal representatives, and ensure associated communications are maintained until the disturbance or outage condition is corrected.
For Transmission related interruptions, the designated Transmission employee will provide only appropriate available relevant non-public transmission function information to the Municipal Account Manager and Municipal representative, including the out-of service transmission facilities, repair progress, and an estimated restoration time. No other non-public transmission function information will be shared unless permitted under the Standards of Conduct exceptions.

(Appendix 7.A provides a key contact information for municipal customers.)

7.1.4 Training and Qualifications
Customer Services shall be responsible for ensuring all personnel assigned to Customer Experience roles described herein are adequately trained and exposed to necessary business processes and information systems.
7.1 Call Centers
The Company’s Customer Experience Section of the Incident Command System shall have primary responsibility for ensuring adequate procedures, resources, and technology are in place to communicate safety, outage, and restoration information with impacted customers during large outage events or emergencies involving the electric system.

7.1.1 Roles and Responsibilities (See Appendix 10 for key Call Center contact information)

7.1.1.1 Call Center Director - or their designee, shall report to the Customer Experience Section Chief or their delegate, and be responsible for:

7.1.1.1.1 Activating the various call center locations for handling outage calls from customers as well as maintaining normal communications for non-affected customers.

7.1.1.1.2 Collaborating with the Customer Experience Section Chief and Incident Commander or their designees to ensure consistent and accurate information is being communicated to customers;

7.1.1.1.3 Establishing appropriate shifts and coverage levels based on call volumes;

7.1.1.1.4 Ensuring emergency calls and critical customer issues are properly elevated within the Incident Command organization through designated information systems or verbally when required;

7.1.1.1.5 Verifying all available communications channels are working properly and allowing affected customers to identify outages and obtain restoration status information.

7.1.1.1.6 Verifying with Information Technology that all necessary information systems and processes are available and functioning properly; and,

7.1.1.1.7 Tracking and communicating performance metrics during the restoration event, and providing various statistics to the Customer Experience Section Chief to be utilized by the Incident Commander.

7.1.2 Activation

7.1.2.1 Yellow Alert – The Customer Experience Section Chief or their delegate shall have authority for activating Customer Experience emergency business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Customer Experience business processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant electric system damages and customer outages. Activation may be required in advance of actual damages or outages, to assure needed resources
and processes are in place to effectively respond to affected customer inquiries and reports when outages start occurring.

7.1.2.2 Red Alert - The Customer Experience Section Chief or their delegate shall have responsibility for activation of emergency Customer Experience business processes whenever a Red Alert has been declared and significant electric system damages and customer outages are occurring or expected to occur.

7.1.3 Emergency Processes

7.1.3.1 Call Center Staffing - In preparation for or response to emergencies or large outage events which may impact electric customers, the Call Center Director or their designee should collaborate with the Customer Experience Section Chief or their designee to assess the probability and scope of anticipated impacts on customers based on the projected or actual categorization (Level I – IV) of an event. Gathered information should be used to execute established on-call groups, based on the Level of event. When call-in procedures are needed, the Call Center Director or their designee shall utilize the Everbridge notification system to notify the appropriate on-call groups.

The Call Center Director is responsible for monitoring the status of emergencies and restoration efforts, and continuously assessing the appropriateness and effectiveness of resource levels and customer interfacing processes.

7.1.3.2 Call Center Business Continuity - On occasion, a primary Call-In Center work location may be unavailable during the Company’s response to a significant outage event or emergency. Under this scenario, the Call Center Director shall be responsible for collaborating with the Customer Experience Section Chief and developing alternative resource staffing and call routing plans, until the primary location is available or the emergency condition is no longer in place.

7.1.4 Training and Qualifications

Customer Services shall be responsible for ensuring all personnel assigned to Customer Experience roles described herein are adequately trained and exposed to necessary business processes and information systems.
7.3 Business Offices

Local Business Offices play a critical role in supporting LG&E and KU communities and customers, especially when telephonic and electronic communication services have been impacted by severe weather, a natural disaster, or other significant emergency. The Company’s Customer Experience Section of the Incident Command System shall have primary responsibility for ensuring adequate procedures and resources are in place to accommodate customer service needs with normal communications mediums are unavailable during large outage events or emergencies involving the electric system.

7.3.1 Roles and Responsibilities (See Appendix 10 for key Business Office contact information)

7.3.1.1 Business Office Director – or their designee, shall report to the Customer Experience Section Chief or their delegate, and be responsible for:

7.3.1.1.1 Working with areas affected by outages or emergencies and making local business offices available for customers to provide outage information and obtain updates on their restoration status.

7.3.1.1.2 Collaborating with the Customer Experience Section Chief and Incident Commander or their designees to ensure consistent and accurate information is being communicated to customers;

7.3.1.1.3 Ensuring emergencies and critical customer issues are properly elevated within the Incident Command organization through available communications mediums;

7.3.1.1.4 Establishing appropriate shifts and coverage levels based on outage counts and anticipated durations;

7.3.1.1.5 Tracking and communicating key customer traffic and outage information during the restoration event, and providing various statistics to the Customer Experience Section Chief to be utilized by the Incident Commander.

7.3.2 Activation

7.3.2.1 Yellow Alert – The Customer Experience Section Chief or their delegate shall have authority for activating Customer Experience emergency business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Customer Experience business processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant electric system damages and customer outages. Activation may
be required in advance of actual damages or outages, to assure needed resources and processes are in place to effectively respond to affected customer inquiries and reports when outages start occurring.

7.3.2.2 Red Alert - The Customer Experience Section Chief or their delegate shall have responsibility for activation of emergency Customer Experience business processes whenever a Red Alert has been declared and significant electric system damages and customer outages are occurring or expected to occur.

7.3.3 Emergency Processes
7.3.3.1 Business Offices Operations – Whenever a Yellow or Red Alert is issued, the Business Office Director or their designee should collaborate with the Customer Experience and Operations Section Chiefs or their designees to assess the probability and scope of anticipated impacts on customers and normal communications channels based on the projected or actual categorization (Level I – IV) of a declared event. Collected information should be used to:
• Determine if Business Offices should be operated outside of normal business hours; and,
• Determine if resource levels in Business Offices should be supplemented to facilitate effective service for anticipated or actual increases in customer traffic.

The Business Office Director is responsible for monitoring the status of emergencies and restoration efforts and continuously assessing the appropriateness and effectiveness of resource levels, customer interfacing processes, and facility availability for Business Offices in impacted areas.

7.3.3.2 Business Availability and Functionality – When a service area has been greatly impacted by severe weather, and significant customer outages have been experienced, the Business Office Director should coordinate assessment of business offices in affected service areas to:
• Confirm the availability and physical functionality of the Business Office;
• Confirm the availability and functionality of key information and communications systems;
• Determine if temporary electric supply (generator) is needed; and,
• Determine if an alternative facility or mobile command center is needed to facilitate anticipated or actual customer traffic.
When deficiencies are identified, the Business Office Director shall coordinate with the Customer Experience, Operations, and Logistics Section Chiefs to secure whatever resource is necessary to remedy the deficiency or to identify alternatives for meeting customer needs.

### 7.3.4 Training and Qualifications

Customer Services shall be responsible for ensuring all personnel assigned to Customer Experience roles described herein are adequately trained and exposed to necessary business processes and information systems.
7.4. Emergency Management Outreach

Systematic and routine outreach is needed with local, regional, and state government and emergency response agencies to assure the Company is able to effectively work with said agencies during significant emergencies or outage events involving the Company’s electric system.

7.4.1. Roles and Responsibilities (See Appendix 10.0 for key internal Emergency Management Outreach contact information)

7.4.1.1. Emergency Planning and Preparedness Manager (EPP Manager) – or their designee, shall be responsible for developing and executing the Company’s emergency management outreach strategy and programs, and for developing Alert Level Task lists which assure LG&E and KU can effectively coordinate with emergency response agencies in their service territories when responding to emergencies or significant outage events impacting the electric distribution systems. The EPP Manager is also responsible for working closely with the Incident Commander, Customer Experience Section Chief, and key customer interfacing personnel to identify, develop, and execute critical outreach functions and assure consistent and accurate communications exchanges with key emergency management leaders in areas served by the Company during Yellow and Red alert status.

7.4.1.2. Emergency Operations Center (EOC) Representative – shall be responsible for representation of the Company in active EOC’s in the LG&E and KU service areas as requested by associated emergency management representatives or as assigned by the Incident Commander or EPP Manager. The EPP Manager or their delegate shall be the primary Company representative responsible for coordinating emergency response efforts with the State Emergency Operations Center in Frankfort, with the duties of Emergency Support Function – Private Sector (ESF-16). At the County Level the EPP Manager or their delegate shall be the primary Company representative responsible for coordinating emergency response efforts in County Emergency Operation Centers with the Duties of Emergency Support Function – Utilities (ESF-12)

7.4.2. Activation

7.4.2.1. Blue Alert – the EPP Manager shall be responsible for working with Operations and Retail Management to develop and coordinate execution of emergency management outreach strategies and plans. Outreach strategies and plans should be
Electric Distribution
Emergency Preparedness and Response Plan

Section 7.4
Emergency Management Outreach

Effective Date: 9/30/2014
Version No. 1

Electric Distribution
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designed to assure the Company can effectively communicate and coordinate with key local, regional, and state emergency response agencies during preparation for or response to significant emergencies or outage events involving the electric system.

7.4.2.2. Yellow Alert – the EPP Manager or their delegate shall be responsible for staying alert to internal Alert levels and external threats which may indicate the need to execute Yellow Alert task lists specific to emergency management outreach. Additionally, the EPP Manager shall be responsible for staying alert to emergency events or threats on the local, regional, and state level which could place the LG&E and KU distribution system under Yellow Alert. Whenever a threat is identified, the EPP Manager shall also be responsible for ensuring the Incident Commander or their delegate is aware of the threat.

7.4.2.3. Red Alert – the EPP Manager shall be responsible for coordinating execution of Emergency Management Outreach Red Alert Task list items whenever a Red Alert has been declared by the Incident Commander or their delegate. Additionally, the EPP Manager shall be responsible for staying alert to emergency events or threats on the local, regional, and state level which could place the LG&E and KU distribution system under Red Alert. Whenever a threat is identified, the EPP Manager shall also be responsible for ensuring the Incident Commander or their delegate is aware of the threat.

7.4.3. Emergency Management Outreach Focus Areas

The following agencies shall be the Company’s primary emergency management outreach targets:

7.4.3.1. Kentucky Emergency Management (Appendix 7.C contains key Emergency Management contact information)

7.4.3.1.1. Kentucky Emergency Management Regions – KYEM is made up of eleven regions, each of which is assigned a Regional Response Manager.

7.3.1.1.1..1. Region 1 – Benton Office
7.3.1.1.1..2. Region 2 – Owensboro Office
7.3.1.1.1..3. Region 3 – Glasgow Office
7.3.1.1.1..4. Region 4 – Louisville Office
7.3.1.1.1..5. Region 5 – Frankfort Office
LG&E and KU serve customers in all but Region 3. The EPP Manager is responsible for coordinating with Operations and Retail management to coordinate the Company’s activities and representation in Regional Emergency Management meetings, exercises, or activations.

7.3.1.1.1.2. **Emergency Support Function (ESF)** – KYEM defines utilities as ESF-12 for public entities and ESF – 16 for Private Sector Utilities; LKE participates in planning meetings, drills, and staffs the Central EOC in Frankfort during emergencies involving LG&E and KU electric or gas facilities. The EPP Manager or their delegate is responsible for representing the Company on ESF-16 or ESF-12 exercises and activations.

7.3.1.1.3. **Private Sector Working Group (PSWG)** – The Company is one of the founding members of the PSWG, which is in partnership with the KYEM; the PSWG participates in State emergency planning, exercises, and responses (through the VBEOC - on control console at the State EOC). The EPP Manager or their delegate is responsible for participating in this Group.

7.3.1.1.4. **Central United States Earthquake Consortium (CUSEC)** – LG&E and KU participate with state government and the eight surrounding states on drills and emergency planning exercises for catastrophic earthquakes. The EPP Manager is responsible for determining the level of participation in this Consortium.

7.3.1.1.5. **Kentucky Emergency Response Commission (KERC)** – Under the authority of KRS 39A placed by the Director of Emergency Management Office and the Governor’s appointment of the primary seated commissioners of the Commission serves as the advisory committee for the overall emergency management and emergency response program of the
Commonwealth. The EPP Manager is responsible for determining the level of participation in this Commission.

7.3.1.6. **Local Emergency Planning Committees (LEPC)** – all counties are required to conduct at least two emergency preparedness and planning meetings annually to qualify for Federal funding. Critical counties for LKE include Jefferson, Oldham, Bullitt, Nelson, Trimble, Owen, Clark, Fayette, Ohio, Fayette, Laurel, Bell, Christian, Muhlenberg, and Harlan. The EPP Manager is responsible for coordinating with Operations and Retail management to coordinate the Company’s activities and representation in LEPC meetings, exercises, or activations.

7.3.1.2. **Virginia Emergency Management Association** (Appendix 7.C contains key Emergency Management contact information)

7.3.1.2.1. **Emergency Management Region** – Old Dominion Power’s (ODP) service area is in the Virginia Emergency Management Region IV, which includes Wise, Dickenson, Lee, and Russell Counties. The EPP Manager is responsible for coordinating with Old Dominion Power Operations and Retail management to coordinate the Company’s activities and representation in Regional Emergency Management meetings, exercises, or activations.

7.3.1.2.2. **Annual Joint Utilities Meeting** – the Virginia State Corporate Commission (VSCC) and Virginia Emergency Management Association host annual Joint Utilities Emergency Preparedness and Response meetings. The EPP Manager is responsible for coordinating with Old Dominion Power Operations and Retail management to coordinate the Company’s activities and representation in these annual meetings, and any related exercises, or activations.

7.3.1.2.3. **Emergency Support Function (ESF)** – Virginia EM defines utilities as ESF-12 for public entities; LKE participates in planning meetings, and reports critical outage and customer information to the VSCC for dissemination to the Virginia EM. The EPP Manager is responsible for coordinating with Old Dominion Power Operations and Retail management to coordinate the
7.4.4. Training and Qualifications

The EPP Manager is responsible for ensuring all personnel assigned to Emergency Management Outreach roles are adequately trained and exposed to necessary business processes and information systems.
8. Logistics Section

**Purpose**
EPRP Section 8.0 introduces the high level organizational structure, roles, and associated responsibilities for the Logistics Section of the Company’s Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

**Scope**
EPRP Section 8.0 and its Subsections cover all resources assigned to the Logistics Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 8.1.

**Responsibilities**
The Logistics Section of the Incident Command structure has overall responsibility for developing and executing preparedness and response plans which assure resource and logistics needs are effectively fulfilled during responses to significant outage events or other emergencies on the electric distribution system.

**Training and Qualification**
The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. *(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)*
References

Revisions
None
8.1. Resources

Supply Chain (Logistics Section) has worked with Electric Distribution Operations to develop business processes which help assure the Company has adequate resources available to respond to significant outage events and emergencies on the electric distribution system. During emergency responses, Supply Chain will provide and/or coordinate the following functions for the Company:

- Procurement Activities, including:
  - Establishment of commercial terms, billing rates, and current insurance forms for nonresident/off system resources;
  - Securing adequate lodging for all affected mobilized and off system resources;
  - Securing necessary meals for all responding persons;
  - Provision of special services such as laundry, etc…

- Material Management Activities, including:
  - Storeroom operations;
  - Material logistics, including job site delivery and/or operation of mobile storerooms at established personnel staging areas.

- Coordination with Operating Services on:
  - Facility management;
  - Staging areas, including establishment and daily management;
  - Security, including National Guard escorts.

- Interface with Transportation, including:
  - Vehicle leases and rentals;
  - Miscellaneous equipment needs;
  - Vehicle fueling.

The procedures, roles, and responsibilities described herein are designed around Level III and IV events, but are scalable and transferable to all categories of events.

8.1.1. Roles and Responsibilities (See Appendix 10 for key Supply Chain contact information)

8.1.1.1. Supply Chain Restoration Coordinator – reports to or is the Logistics Section Chief(s), and has overall responsibility for developing Alert Level task lists for Supply Chain functions, and:

8.1.1.1.1. Working with Incident Commanders, Senior Management, and Operations Sections Chiefs to procure and provide identified material, transportation, equipment, meals, and general supply needs.
8.1.1.2. Assuring the Logistic Section Chief in the Incident Command Structure is provided sufficient data to trigger logistics processes necessary to support restoration resources.

8.1.1.3. Assuring the reporting needs of the Incident Command structure are satisfied;

8.1.1.4. Working with the Information Technology Director to assure that needed information management systems meet supply and logistics needs; and

8.1.1.5. Conducting internal update and planning meetings with Supply Chain personnel responsible for support functions, to include other organizational areas as necessary and needed.

**8.1.2. Area Lead** - position is responsible for managing the Supply Chain restoration support function(s) in a specific geographical area. Depending on the magnitude of the restoration effort, there may be multiple Area Leads. This position will:

8.1.2.1. Have an on-site presence in the affected area

8.1.2.2. Direct the site specific supply chain support functions, specifically Material, Lodging and Food requirements

8.1.2.3. Maintain constant communications with the Supply Chain Restoration Coordinator and local Operations management

The formal naming of an Area Lead(s) will be dependent upon the location of the restoration event(s).

8.1.3. **Crew Notification Interface** – or their designee, shall have overall responsibility for working with designated positions in the Work Planning Section to track internal crew mobilization and committed off system resources. The primary purpose of this position is to have a complete understanding of external crews being mobilized for the restoration effort, communicating this information to, a minimum, the (Supply Chain) Area Lead, Materials Supervisor, etc... and securing contract agreements, namely Commercial Terms, billing rates and current insurance forms. This position is also responsible for:

8.1.3.1. Ensuring a contract is in place to cover the work to be performed, preferably as resources are being mobilized and before work commences; and

8.1.3.2. Communicating the safety, business, equipment and invoicing requirements of the Company.
8.1.1.4. **Food Coordinator** - or their designee, shall have overall responsibility for helping secure adequate meals for labor resources allocated to the restoration effort. The Food Coordinator is responsible for contacting and establishing specific local restaurants, preferably in the area where either work is being performed or where crews are being lodged, in the initial stages of a restoration effort, capable of serving meals to potential external and company crews responding to a restoration event. The duration of this function will be determined by the time needed to support restoration personnel requiring the use of staging areas or as requested by local Operations Management. Food coordinator will ensure the proper use of purchasing cards for payment.

8.1.1.5. **Materials/Supplies Coordinator** - or their designee, shall have overall responsibility for managing the material support functions, including:

8.1.1.5.1. Working with area storerooms, Operations Directors, and suppliers to maintain necessary materials and supplies inventory levels, and keeping material providers advised of projected material needs based on reported system damages;

8.1.1.5.2. Overseeing local storeroom operations and material logistics;

8.1.1.5.3. Communicating with South Service Center on transformer logistics support;

8.1.1.5.4. Ensuring adequate materials are available at designated staging sites;

8.1.1.5.5. Tracking and reporting material usage;

8.1.1.5.6. Managing material return processes, post restoration.

In the event of a single location restoration effort, the Material Lead function will be performed by a delegated person. This lead will be assigned by the Supply Logistics Section Chief and typically be either a local Material Specialist, or Material Supervisor responsible for the impacted storeroom/warehouse.

In a multi-site restoration effort, a Material Lead will be assigned to each impacted area and oversee the operations of the associated storerooms/warehouses in that impacted area. Material Leads will be responsible for the material support functions (denoted above) in their assigned area. Also, a Material Supply Coordinator function will be established to work with the individual Material Leads and all affected suppliers to ensure that an adequate and optimized flow of materials to all affected sites is established and maintained throughout the restoration event.
8.1.1.6. **Lodging Coordinator** – or their designee, shall be responsible for identifying and securing the appropriate number of hotel rooms, in the appropriate areas of the restoration area, consistent with the number of external crew personnel that are responding to the event. This position will also track the number of rooms available and occupied as well as an expense recap of lodging costs throughout the restoration event and report in Electric Distribution’s designated resource tracking database.

8.1.1.7. **Logistics Coordinator** – In a Level III or IV restoration event, this position is primarily responsible for interfacing with Operating Services on the establishment and operation of external staging areas.

8.1.1.8. **Transportation Leader** – or their designee, shall have overall responsibility for ensuring adequate transportation and equipment resources are available to respond to restoration efforts, including light duty vehicles, heavy duty vehicles, power operated equipment, and trailers.

The TL shall also be responsible for working with fueling stations and mobile fueling providers, as needed, to ensure adequate fuel is available for vehicles and power operated equipment during emergencies.

8.1.1.9. **Purchase Card Support** – position is responsible for ensuring Purchasing Cards are active and levels are adequately set and maintained throughout the event and will respond immediately to any administrative issues that arise.

8.1.1.10. **Data Collection** – In a Level III or IV event, this position is responsible for collecting and tracking data associated with Supply Chain restoration activities including:

8.1.1.10.1. Quantities of materials (poles, transformers, storm kits, etc…) and delivered from the Material Coordinator or Area Lead.

8.1.1.10.2. Number of hotel rooms reserved and utilized – from the Lodging Coordinator.

8.1.1.10.3. Fuel consumption – from the Transportation/Fuel Coordinator.

8.1.1.10.4. Number of meals served – from the Food Coordinator or Logistics Coordinator.
8.1.2. Emergency Response Activation

8.1.2.1. Yellow Alert – The Logistics Section Chief, Incident Commander, or Operations Manager or their delegates shall have the authority to direct activation of ‘storm response’ Supply Chain processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency supply chain processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to enable effective management, administration, and treatment of incremental resources.

8.1.2.2. Red Alert - The Logistics Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have responsibility for activation of emergency supply chain processes whenever a Red Alert has been declared, particularly when an event has been established as Level III or IV for any Operations area.

8.1.3. Key Business Processes

8.1.3.1. Contracting External Resources

During a declared weather event LG&E and KU Services Company (LKS) may call upon four categories of external resources for assistance:

- LKS’s native contractors;
- Primary Mutual Assistance Partners who are members of the Southeast Electric Exchange (SEE), Great Lakes Mutual Assistance (GLMA), or Midwest Mutual Assistance (MMA);
- Secondary Mutual Assistance Partners who are not members of the SEE, GLMA, or MMA;
- Non-native contractors – typically obtained from the Mutual Assistance Utilities, comprised of two types
  - Preferred (GSA on File and Non-GSA)
  - All Others

The contracting for each of these resources shall be described as follows:

8.1.3.1.1. Native Contractors - Native Contractors are defined as contractors in which LKS has an established contract or ongoing relationship. In the event LKS
requires external resources for storm restorations, LKS can rely on the contracts with these contractors as the basis for the rates these contractors will charge. For minor storms (level I or II) money is included in the contract award totals for the current overhead contractors (see Appendix 8.A for current listing and contact information for Native Contractors) or for other certified contractors expenses less than $50K will be covered by standard purchase orders entered by distribution operations. However for major storms (level III or IV, usually where the resource room concept is implemented), an additional requirement in using these contractors will be the completion and proper approval of a Sole Source Authorization (SSA) form to cover storm related work and the separate processing of storm related invoices.

Should a native contractor be requested to perform work outside of the scope of their standard contract, an amendment to or special storm contract may be appropriate.

Native LKS contractors mobilizing resources to a restoration event from outside of the LKS system will need to forward a roster and the applicable wage and equipment rates to the designated Supply Chain contact.

8.1.3.1.2. Primary Mutual Assistance Partners - LG&E KU Services (LKS) is a party to a Mutual Aid Agreement, as part of the Southeast Electric Exchange (SEE), which requires the member utilities to offer assistance (to each other) in the case of a declared weather event. Likewise, LKS is a member of the Great Lakes Mutual Assistance and Midwest Mutual Assistance groups. (See Appendix 9.C for primary mutual assistance group members and contact information) All member companies are required to sign the Edison Electric Institute’s (EEI) Mutual Assistance Agreement. When assistance is needed from these mutual assistance group members, LKS will request assistance via a Mutual Aid conference call mechanism. No stand-alone commercial agreement is required for member utilities as a working agreement is already in place through membership in SEE or EEI.

Responding utilities will be directed to forward a copy of their roster to Work Planning, as established in EPRP Section 9.1. The only additional
requirement will be the completion and proper approval of a Sole Source Agreement form to cover the work by the Crew Notification Interface or as designated by the Supply Chain Restoration Coordinator.

8.1.3.3. Secondary Mutual Assistance Partners - If Mutual Assistance is required from utilities that are not part of the SEE, (such as GLMA and MMA) Supply Chain will send the LKS Mutual Aid (MA) Commercial Agreement to that utility. The MA Commercial Agreement will, among other things, contain terms and conditions, request for rates, and establish LKS business requirements, i.e. housing/staging policies. In addition to the signed Commercial Agreement, a roster will be requested from the responding utility.

8.1.3.4. Non Native Contractors - LKS defines Non-native Contractors as all contractors that do not normally work on the LKS system that are secured by LKS to deliver assistance in response to significant outage events or other emergencies on the Company’s electric distribution system. (Please see Appendix 8.B for listing and contact information of Non Native Contractors LKE has worked with in the past.)

These contractors are categorized into two groups – Preferred and All Others.

8.1.3.4.1. Preferred Non-Native Contractors - Preferred Non-Native Contractors include business partners that have been preapproved to work on the LKS system and are preferred due to their safety rules and performance, proximity to the LKS service area, and pricing. The Company already has General Service Agreements (GSA) in place for some of these contractors.

When GSA resources are secured to provide assistance during an emergency response, they should be requested to provide the following information to a designated Supply Chain contact:

- Current insurance certificate
- Applicable wage and equipment rates
Non-GSA contractors will also be asked to submit a signed GSA document (in addition to the above items), or will be allowed to mobilize under a properly approved Intent to Deviate document.

The only additional requirement will be the completion and proper approval of a SSA form to cover the work.

8.1.3.1.4.2. Other (Non-Preferred) Non-Native Contractors - When non-preferred non-native off system resources are secured to provide assistance during responses to significant outage events or emergencies, they shall be required to sign the standard LKS General Services Agreement (GSA) and LKE Storm Restoration Agreement Contract. The contractor should also be required to provide their current insurance form.

The Crew Notification Interface shall also be responsible for routing a completed Sole Source Agreement to cover the proposed scope of work.

8.1.3.2. Materials Logistics

Typically, during blue sky outage events or Level I-II emergency events, resident Company and business partner crews are able to utilize locally stored materials to restore outages and repair system damages. During Level III and IV events, incremental materials are often needed as supplemental crews are brought in to help respond, or as local crews deplete local supplies. Supply Chain has developed supplemental business processes to provide for necessary materials and supplies during restoration and repair efforts following large storms or emergencies which damage the electric distribution system. (Please see Appendix 8.C for the Logistics Section’s Emergency Response Materials Logistics business process flow, and Appendix 8.D for a listing of Storeroom locations and key contact information.)

8.1.3.2.1. Material Leads and Coordinators

8.1.3.2.1.1. Single Location Restoration Effort

- The Material Coordinator function will be performed by a designated Material Lead.
- The Material Lead will be assigned by the Supply Chain Restoration Coordinator and typically be either:
  - The local Material Specialist, or
8.1.3.2.2. Multi-Site Restoration Effort

- A Material Lead will be assigned to each impacted area and oversee the operations of the associated storerooms/warehouses in that impacted area
- Material Leads will be responsible for the material support functions (denoted above) in the assigned area
- A Material Supply Coordinator function will be established to work with the individual Material Leads and all affected suppliers to ensure that an adequate and optimized flow of materials to all affected sites is established and maintained throughout the restoration event.
- Material Leads will communicate material requirements and material issues to the Material Supply Coordinator for resolution with the external suppliers

8.1.3.2.3. Storm Kits - “First response” Storm Kits have been developed for LG&E and KU operating areas and are stocked by the Company’s electric materials vendor and in Company storeroom locations throughout the LG&E and KU service areas. These kits are assigned to non-resident resources during level II – IV emergency events, and are designed to enable off system crews to restore customer outages and make routine type repairs for a period of at least 24 hours. During this period, the Incident Commander, Work Planning, Operations Section, and Logistics Section evaluate the scope and scale of system damages and assess overall and site specific material needs. After damage assessments are completed, additional orders for specific material needs can be placed with the designated Materials/Supplies Coordinator or Lead. (Please see Appendix 8.E for the LG&E and KU Storm Kit locations, quantities, and inventories.)

8.1.3.2.4. Deleted

8.1.3.2.5. Storm Material Trailers - Storm Material Trailers have been developed to be delivered to hard hit sites or staging areas. The Company’s electric materials vendor maintains these trailers, which contain a specified inventory of common storm use materials for LG&E and KU. These trailers

- The Material Supervisor responsible for the impacted storeroom or warehouse
8.1.3.3. Vehicles and Equipment

The Manager Transportation or their delegate shall be designated as Transportation and Fuel Coordinator during Level II-IV events, and shall be responsible for maintaining a listing of vehicles, equipment, and fuel (mobile and stations) providers that support emergency restoration efforts. The Transportation Coordinator shall work with the Logistics Section Supply Chain Coordinator to meet all internal fleet needs during responses to significant outage events or other emergencies involving the electric distribution system. (Please see Appendix 10 for a listing of key Vehicles and Equipment contacts.)

8.1.3.4. Lodging Setup

Hotels will be the preferred method of lodging for non-native resources providing assistance to restoration efforts or other emergencies. Supply Chain shall be responsible for designating a Lodging Coordinator during storms and maintaining a list of available lodging locations, along with detailed procedures for securing, and accounting for rooms. (Supply Chain utilizes external resources and databases (example: Convention Centers, Visitors Bureaus, etc...) to identify lodging for external resources as well as track room usage and availability on an on-going basis.)

During significant restoration events, where incremental off-system resources are brought in to assist with response efforts, Work Planning should provide the Lodging Coordinator with head counts in Electric Distribution’s designated resource management software. The Lodging Coordinator is responsible for using entered resource data to determine the number, and geographic location, of required rooms. Resource/Operations Managers shall be responsible for coordinating lodging needs with Supply Chain.

If available hotels do not satisfy housing needs for incoming or active restoration workers, staging areas may be needed. Please reference Section 8.3 for Resource Staging procedures.

8.1.3.5. Restaurant/Meals Setup
Supply Chain has established business processes for setting up restaurants/meals during significant outage events or emergencies to provide necessary meals for resources supporting restoration and response efforts (Please see Appendix 8.H for the LG&E and KU restaurant set-up procedures.) Supply Chain is responsible for maintaining a listing of available restaurants and meal providers by Operating area, and for designating a Food Coordinator during responses to significant outage events or emergencies.

Operations Centers needing meals shall contact the Supply Chain Restoration Coordinator or Food Coordinator to invoke Restaurant Set-Up processes.

8.1.3.6. Purchasing Card Setup
8.1.3.6.1. Supply Chain Storm Purchasing Cards
Supply Chain’s Storm Purchasing Cards are intended to be used primarily in Level II-IV storm events, particularly in heavily impacted areas. Supply Chain shall be responsible for ensuring that purchasing card procedures are in place to enable purchases under three primary categories:

- Hotels
- Restaurants
- Miscellaneous Materials

Operations Management personnel in need of hotels, restaurants or miscellaneous materials or supplies should notify the Supply Chain Restoration Coordinator or the appropriate designee. Supply Chain will designate central points of contact (Purchasing Card Support) that will be responsible for coordinating set up and payment of lodging, restaurants, and materials throughout the restoration period.

8.1.3.6.2. Individual Storm Purchasing Cards
Individual storm purchase cards are available for Team Leaders and Birddogs, and are intended to be used for procuring lodging, meals, and miscellaneous materials where Supply Chain Storm Purchasing Cards are not set up or available. Operations Management should contact Supply Chain’s designated Purchasing Card Support to activate purchase cards, adjust limits, or assist with any related issues.

8.1.4. Training and Qualifications
8.1.4.1. Supply Chain and Operating Services management personnel shall be responsible for ensuring all personnel assigned to Logistics Section roles described herein are adequately trained on necessary business processes and information systems required to effectively fulfill procedures defined in Section 8.1.
8.3. Human Resources Support

To be developed

8.3.1. Roles and Responsibilities

8.3.1.1. Human Resources Director – or their designee, shall function as the support mechanism for employees and families of employees who are working on restoration activities, but also have crisis issues at home due to the weather event or emergency. The Human Resources Director will work with various outside entities to provide support to employees’ families when in need of basic functions such as food, shelter, and home repairs.

8.3.2. Activation

8.3.2.1. Yellow Alert

To be developed

8.3.2.2. Red Alert

To be developed

8.3.3. Emergency Processes

To be developed
8.3. Facilities and Staging Areas

The Logistics Section has worked with Electric Distribution Operations, Retail, and Supply Chain to develop business processes and an organizational structure which assures adequate availability and effective operations of Company facilities and staging areas during responses to significant emergencies or outage events.

8.3.1. Roles and Responsibilities (See Appendix 10 for key Facilities and Staging contact information)

8.3.1.1. Facilities Section Chief—reports to or is the Logistics Section Chief(s), and has overall responsibility for development of key Alert Level Task lists for Facilities and Staging during emergencies, and:

8.3.1.1.1. Working with Incident Commanders and all other Section Chiefs to provide, operate, and maintain needed facilities and staging areas as needed or requested during Company responses to significant outage events or emergencies involving the LG&E and KU electric distribution systems.

8.3.1.1.2. Assuring the Logistic Section Chief in the Incident Command Structure is provided sufficient data to trigger logistics processes necessary to support restoration resources.

8.3.1.1.3. Assuring the reporting needs of the Incident Command structure are satisfied;

8.3.1.1.4. Working with the Information Technology Director to assure that needed information management systems meet logistics needs; and

8.3.1.1.5. Conducting internal update and planning meetings with Operating Services personnel responsible for support functions, to include other organizational areas as necessary and needed.

8.3.1.2. Staging Lead - position is assigned by the Logistics Section Chief, and is responsible for collaborating with the Logistics Section Chief and Lodging Coordinator to identify housing and staging needs for responding resources, and determining if incremental staging areas are needed to be set up and operated during responses to significant emergencies and outage events involving the electric distribution system.

8.3.1.3. Facility Maintenance Lead – position is assigned by the Logistics Section Chief, and is responsible for collaborating with the Logistics Section Chief to identify and respond to incremental facility needs in preparation for or response to significant emergencies or outage events.
emergencies or outage events involving the electric distribution system. This includes, but is not limited to:

- Expanding facility operations beyond normal business hours, including lighting, air conditioning, security, and facility maintenance.
- Providing for incremental janitorial services and maintenance personnel to assist with upkeep of facilities when incremental resources are brought in to support emergency response.
- Providing for traffic control and parking attendants for incremental resources.
- Providing for room reconfiguration and set up, to enable establishment of central war rooms/resource management rooms.
- Providing for backup power supplies.

**8.3.1.4. Security Leader** – typically assigned to the Manager Corporate Security or their delegate, this position is responsible for collaborating with the Logistics Section Chief, Lodging Coordinator, Staging Lead, and Operations Section Chief(s) to identify and respond to incremental security needs during responses to emergencies or significant outage events on the electric distribution system. This includes, but is not limited to providing for:

- Facility Security
- Staging Area Security
- Job Site Security/Crowd Control
- Hotel Parking Lot/Vehicle Security
- Traffic Control
- Escorting Company Personnel
- Guarding Company Assets

**8.3.2. Emergency Response Activation**

**8.3.2.1. Yellow Alert** – The Logistics Section Chief, Incident Commander, Customer Experience Section Chief, and Operations Section Chief or their delegates shall have the authority to direct activation of ‘storm response’ Operating Services business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Operating Services processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages, particularly when an event necessitates extended
work hours and incremental non-resident resources to be brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed facilities and staging areas are in place to facilitate effective management, administration, and treatment of responding resources.

8.3.2.2. Red Alert - The Logistics Section Chief, Operations Section Chief, Customer Experience Section Chief and Incident Commander or their delegates shall have responsibility for activation of emergency Operating Services emergency response processes whenever a Red Alert has been declared.

8.3.3. Emergency Business Processes
8.3.3.1. Facility Maintenance – During responses to significant outage events, the limitations of business offices, operating centers, call centers, storerooms, corporate offices, etc. and associated facility maintenance business processes may be exceeded. The Facilities Section Chief shall be responsible for working with the Incident Commander, and all other Section Chiefs to identify and react to facility needs which exceed normal physical, business processes, and human resources capabilities. The Facility Section Chief shall also be responsible for executing associated Alert Level task lists and working with Operating Services, Security, and Supply Chain to provide for incremental/needed:
- Facility maintenance support
- Janitorial services
- Security
- Debris removal or dumpsters
- Traffic and parking control
- Snow removal
- Power supply (generators) and fuel
- War room setup and breakdown
- Resource staging

8.3.3.2. Staging Areas – Resource staging areas may be needed during responses to significant outage events or emergencies involving the electric distributions system, particularly for Level III and IV events, where incremental off system resources are brought in to support response efforts. Staging areas activities include, but are not limited to the following:
• Resource check-in, safety passporting, and processing
• Housing
• Materials distribution, staging, and returns
• Food preparation and distribution
• Clothes laundering
• Debris disposal and staging
• Showers and Restrooms
• Vehicles and Equipment staging and security
• Fuel dispensing

The Facilities Section Chief shall be responsible for collaborating with the Logistics Section Chief, Incident Commander, Operations Section Chief, Supply Chain Lodging Coordinator, and Work Planning Section Chief to identify staging and housing needs and to set up and operate staging areas when needed. Factors that must be considered when evaluating staging area needs include:
• Number of personnel reporting to a single geographical location – short term and over the duration of the event
• Number and types of lodging and food accommodations available in that area.
• The relative distance of the available accommodations to the work area.

The Logistics Section will continuously coordinate with the Operations Section and Work Planning Sections as external resources are being deployed to the LG&E KU service areas. When the magnitude of responding resources approaches 300 in a single geographical local, the Logistics Section Chiefs will confer with the Incident Commander and Operations Section Chief to determine if and where a staging area should be set up. If a decision is made to establish a crew staging area, the Logistics Section Chief will coordinate with the Staging Lead to evaluate available options, establish expected use, and designate the staging location. Personnel under the Facilities Section Chief will be responsible for overseeing and coordinating set up and operation of the designated staging area. A single staging area for 300 people can typically be set up and operational within twelve to thirty-six hours.

If the staging area is needed to provide food, lodging, showers, etc...the Logistics Director will work with Supply Chain to coordinate needed services with the appropriate contractors and suppliers, and work directly with the Staging Lead on delivery and logistics.
8.3.3. Security - Incremental security needs may be required during responses to emergencies or significant outage events involving the electric distribution system, particularly for Level III and IV events, where incremental off system resources are brought in to support response efforts. Security activities include, but are not limited to the following:

- Facility Security
- Staging Area Security
- Hotel Parking Lot/Vehicle Security
- Job Site Security/Crowd Control
- Traffic Control
- Escorting Company Personnel
- Guarding Company Assets

8.3.4. Training and Qualifications

8.3.4.1. Supply Chain and Operating Services management personnel shall be responsible for ensuring all personnel assigned to Logistics Section roles described herein are adequately trained on necessary business processes and information systems required to effectively fulfill procedures defined in Section 8.3.
9. Work Planning Section

**Purpose**

EPRP Section 9.0 introduces the high level organizational structure, roles, and associated responsibilities for the Work Planning Section of the Company’s Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

**Scope**

EPRP Section 9.0 and its Subsections cover all resources assigned to the Work Planning Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 9.1.

The Work Planning Section Chief (WPSC) has central responsibility for assuring assigned Work Planning resources are properly trained, and efficient and effective business processes are in place, to provide for resource tracking, optimization, and distribution during responses to significant emergencies or outage events involving the electric system. The WPSC is responsible for working closely with the Operations Section Chiefs and Incident Commander to help identify resource needs, and predict restoration durations. This individual shall also be responsible for assuring all necessary Asset Information and Information Technology is available during emergency responses. Finally, the WPSC is responsible for working with Forecasting and Budgeting to ensure costs are accurately accounted for and all necessary financial reporting is completed.
The Emergency Preparedness and Response Team shall be responsible for developing Alert Level Task lists for all critical roles and functions under the Operations Section.

**Training and Qualification**

The EPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. *(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)*

**References**

None

**Revisions**

None
9.1. Resource Planning

Electric Distribution has developed Resource Planning business processes designed to assist Operations with resource tracking, allocation, and administration during emergency responses, to ensure key qualified personnel can focus their attentions on protecting the public, restoring service, and making necessary repairs. The primary focus of the Resource Planning organization is:

- Working with Operations to identify and secure resource needs;
- Maintaining a high level view of resource distribution and estimated restoration times across all service areas;
- Assisting with administratively processing off system resources during check-in and release;
- Accurately accounting for all off system resources in designated information systems;
- Monitoring the availability of inactive resident Company and Contractor resources;
- Maintaining accurate active/assigned resource counts; and,
- Working with Forecasting and Budgeting to assure all resources are accurately accounted for.

9.1.1. Roles and Responsibilities (See Appendix 10.0 for key Work Planning contact information)

9.1.1.1. Reporting Director - or their designee, shall have overall responsibility for:

9.1.1.1.1. Continuously monitoring Estimated Restoration Times (ERT) to assure adequate and equitable distribution of available resources across service areas as customer outage counts change.

9.1.1.1.2. Development and maintenance of standard spreadsheets and associated administrative processes, which provide for timely and accurate accounting and reporting of internal and external resources responding to a restoration effort.

9.1.1.1.3. Scrub resource data in the Resources on Demand system for irregularities.

9.1.1.1.4. Assuring the reporting needs of the Work Planning Chief and Financial Director are satisfied, and for working with the Information Technology Director to assure that needed information management systems meet resource planning needs.

9.1.1.1.5. Developing the Daily Alignment Report (DAR) which highlights overall objectives for the day.

9.1.1.1.6. Executive Report – responsible for compiling the executive report as needed summarizing current outages, resources on hand by classification and other information.
9.1.1.7. Resource Reports – responsible for identifying organizational resource reporting needs and working with Information Technology to develop reports, training tools, and job aids necessary to provide end users timely and easy access during restoration efforts.

9.1.1.8. Specialty Maps and Reports – generate ad-hoc reports and specialty maps as dictated by the situation.


9.1.1.2. Resource Planning Director – or their designee, shall have overall responsibility for developing Alert Level Task lists for the Work Planning Section, and:

9.1.1.2.1. Working with Incident Commanders, Senior Management, and Operations Sections Chiefs to identify resource needs across Energy Delivery based on system damage and predicted restoration durations, and for working with management personnel, mutual assistance groups, and business partners to secure, mobilize, demobilize, and track needed resources.

9.1.1.2.2. Resources - working with the Operations Directors, Operations Resource Rooms, and the Distribution Control Center Directors to establish area specific resource needs and availability, including line technicians, service crews, bird dogs, bull dogs, damage assessors, and post completion inspectors. Also, working with the Resource Transition Leader and Resource Tracking Leader to evaluate and execute alternatives for acquiring resources needed to restore service and repair system damage.

9.1.1.2.3. Communications - establishing and maintaining a central point of contact for all off system resources responding to assist, once delegated by an Incident Commander or Operations Section Chief.

9.1.1.2.4. Assuring the Logistic Chief Incident Command Structure is provided sufficient data to trigger logistics processes necessary to support restoration resources.

9.1.1.2.5. Throughout the restoration effort, responsible for assessing system wide outage counts, damage assessment information, and crew availability data to develop flexible resource allocation plans.

9.1.1.2.6. Continuously works with the Operations Chiefs, and Operations Directors to assure that proposed and executed resource allocation plans meet operational needs. This includes development of mobilization plans and release schedules for off system resources.
9.1.1.2.7. Coordinates with the Operations Resource Rooms to validate existing resources allocated to their work locations.

9.1.1.2.8. Resource Clearing House - serving as a clearinghouse for all offers of assistance by contractors and utilities not engaged by the Company; and, working with the Reporting Director to determine if offered resources are needed and should be secured.

9.1.1.2.9. Release Schedules - works with the Resource Tracking Leader to stay apprised of mobilization and release schedules which may impact off system resources, and assures off system management teams are notified on a timely basis.

9.1.1.2.10. Coordinates with the Operation Directors and Operations Resource Rooms to monitor and modify ERTs at the local area and circuit levels.

9.1.1.3. Resource Tracking Leader - or their designee, shall have overall responsibility for:

9.1.1.3.1. Crew Rosters - securing crew and equipment rosters and coordinating data entry into the centralized Resources on Demand system.

9.1.1.3.2. In-transit information – capturing off-system resources’ departure time and location, and tracking their estimated arrival times.

9.1.1.3.3. Logistics - communicating reporting locations, directions, contact numbers, hotel and food arrangements, and provision of department of transportation exemptions where applicable for off-system crews. Also, interfaces with Logistics ICS organization (by entering lodging requirements in the central resource system) to ensure accommodations are in place for lodging, meals, transportation, security, and staging.

9.1.1.3.4. Resource Data Administration - responsible for maintaining data in the centralized spreadsheets on resident employees and local contract partners that would be utilized in response to customer outages and system damage.

9.1.1.3.5. Terms and Conditions - exchanging critical information with identified available ‘off system’ resources, including contract, safety, operations, and regulatory requirements and keeping the Resource Planning Director apprised of any conflicts that may eliminate an identified resource from assisting.

9.1.1.3.6. As assigned by the Resource Planning Director, responsible for working with the Resource Transition Leader and Operations Directors during restoration efforts to administrate and maintain data on internal and external resources assisting with service restoration and system repair.

9.1.1.4. Resource Check-in Leader – or their designee, shall have overall responsibility for:
9.1.1.4.1. Validating each individual on the roster once they arrive on-site and logging their passport ID number in the central resource system.
9.1.1.4.2. Capturing actual time of arrival in the central resource system.
9.1.1.4.3. Providing lodging and meal information, if available.

9.1.1.5. Damage Assessment Check-in Leader – or their designee, shall have overall responsibility for:
9.1.1.5.1. Instructing and assisting off-system damage assessors on how to download the mobile damage assessment application on their iPad or company loaned device.
9.1.1.5.2. Activating damage assessor log-in ID’s in the central resource system.
9.1.1.5.3. Providing training on how to use the mobile application and contact information for questions once the assessors are in the field.
9.1.1.5.4. Removing access and retrieving loaned devices once the damage assessment crews are released.

9.1.1.6. Resource Pool Leader – or their designee, shall have overall responsibility for:
9.1.1.6.1. Serving as a repository for resource allocations;
9.1.1.6.2. Tracking available and unassigned personnel and business partner resources during restoration efforts;
9.1.1.6.3. Working with the Resource Leader to identify resource needs throughout the ICS;
9.1.1.6.4. Updating resource rosters to reflect assignments to roles in the ICS.

9.1.2. Activation

9.1.2.1. Yellow Alert – The Work Planning Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have the authority to direct activation of Resource Planning whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of Resource Planning shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to support Operations in assuring available resources are accurately accounted for in the designated resource management database.

9.1.2.2. Red Alert - The Work Planning Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have responsibility for activation of Resource
Planning whenever a Red Alert has been declared, and the event has been established as Level III or IV for any Operations area.

9.1.3. **Business Processes**

9.1.3.1. **Resource Tracking** - When Work Planning is activated, a Resource Tracking team will setup in a location designated by the Work Planning Section Chief. This team shall be responsible for tracking mutual assistance and other off-system resources that have committed to assisting in the restoration effort. Assigned Resource Tracking personnel will be responsible for making contact with designated contacts for each committed Company, to confirm crew counts, lodging requirements and estimated times of arrival, and to provide incoming resources with all necessary check-in location and other essential logistical information. All crew level information shall be entered into the Company’s designated resource management database, including estimated arrival times and lodging requirements. Upon receiving crew rosters, assigned Resource Tracking personnel shall be responsible for entering detailed team member information into the designated resource management database.

The central phone number for Work Planning is listed in Appendix 10, and should be used to obtain resource information by all personnel unless otherwise designated by the Work Planning Section Chief. The central email address for the Resource Tracking team is Storm.Resources@lge-ku.com.

All calls made to Work Planning’s central number will be forwarded to the Work Planning Section Chief’s mobile phone when not under a Red Alert. Under Red Alert, and after activation of Work Planning, all calls regarding resource planning will be pushed to designated roll-over lines.

If Resource Tracking shuts down for the night, the designated central phone number must be forwarded to someone’s cell phone until the day shift begins.

*The designated central number and email address should be given to General Foremen as contact information while traveling. They must be manned and monitored at all times.*
9.1.3.2. **Resource Check-In** - The Resource Check-in team is also activated as part of Work Planning. This team will co-locate with Safety at the location designated for safety training or “passporting” mutual assistance and other off-system crews as they arrive. The Resource Check-in team will validate each individual working on our system, will enter them into RoD if necessary and indicate their actual time of arrival.

If the check-in point does not have connectivity to the LG&E/KU network, a few personal WiFi devices are available and should be used by the Resource Check-in team(s). When you turn the device on, it will give you the network name and password. You will then need to connect your PC to this network. You will need power for prolonged use.

Refer to the job aid in Appendix 9.A as a guide on how to track mutual assistance and other off-system resources using Resources on Demand.

9.1.3.3. **Resource Pools** - In large events, there are tasks that can be delegated to every resource within the company willing to assist. These are tasks that do not require a deep understanding of the restoration process. A few examples would include working at staging sites distributing food, coordinating laundry service, and so on.

All “last minute” volunteers will be directed to the Resource Pool Leaders who will log their contact information and capabilities. Other leaders within the ICS structure needing this type of resource should contact the Resource Pool Leaders to identify resource needs and availability.

9.1.4. **Training and Qualifications**

9.1.4.1. **Resource Planning Directors** – the Work Planning Section Chief or their delegate(s) shall have responsibility for ensuring all personnel assigned Work Planning roles receive routine scheduled training which assures associated roles and responsibilities can be efficiently and effectively executed during Level III and IV events.

9.1.4.2. **Resource Leaders** - the Resource Planning Director or their delegate(s) shall have responsibility for ensuring all personnel assigned Resource Planning roles receive routine scheduled training which assures associated roles and responsibilities can be efficiently and effectively executed during Level III and IV events.
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9.2. Mutual Assistance

Mutual assistance is an essential part of the Company’s service restoration process and contingency planning. Restoring power after major storms, natural disasters, or other emergency events is a complex task, and speedy restoration requires significant logistical expertise, along with skilled workers and specialized equipment.

The electric industry’s mutual assistance network serves as an effective and critical restoration resource for electric utilities because of its unique structure; it is both flexible and voluntary, empowering the network to quickly respond to major outage events in the industry. The primary goal of the network is to restore electric service in a safe, effective, and efficient manner. It also:

- Promotes the safety of employees, business partners, customers, and the public;
- Develops strong interdependent relationships among electric utilities;
- Provides a means for electric utilities to receive competent, trained employees and contractors from other experienced utilities;
- Provides predefined mechanisms for sharing industry resources expeditiously;
- Mitigates the risks and costs of member utilities related to major incidents;
- Proactively improves resource sharing during emergency conditions;
- Facilitates the sharing of best practices and technologies that help the electric industry prepare for, and respond to, emergencies;
- Enables a consistent, unified response to large scale emergency events.

The Company has developed a strong network of local and regional mutual assistance partnerships to enable swift and efficient responses to large scale outage events which exceed the capabilities of day-to-day Company resources and resident contractors. Through these partnerships, the Company is able to quickly increase the size of its workforce by accessing needed skilled labor resources and equipment from other utilities to assist with restoration efforts.

The procedures herein describe the mutual aid networks and procedures the Company shall utilize when sufficient resident and local resources are not adequate to safely and quickly restore service to customers and repair the electric delivery system.
9.2.1. Regional Mutual Assistance Groups

RMAGs are organized geographically to meet the needs of electric utility companies during large scale outages or other emergency situations. There are seven primary Investor Owned Utility RMAGs in the United States (see the Edison Electric Institute’s RMAG Map in Appendix 9.B):

- Great Lakes Mutual Assistance Group (GLMA)
- Midwest Mutual Assistance Group (MMA)
- North Atlantic Mutual Assistance Group (NAMA)
- Southeastern Electric Exchange (SEE)
- Texas Mutual Assistance Group (TMA)
- Western Region Mutual Assistance Agreement (WRMA)
- Wisconsin Utilities Association Mutual Assistance Group (WUAMA)

LG&E and KU are members in the GLMA, MMA, and SEE RMAGs. (See Appendix 9.C for primary mutual assistance contact information.) The Incident Commander, Work Planning Section Chief, and Manager Electric Restoration Distribution, or their designee(s), shall be responsible for assuring the Company is adequately represented in all member RMAGs:

- Mutual assistance phone calls, whether the Company is requesting, releasing, or holding resources;
- Preparedness and planning meetings;
- Policy making decisions; and
- Reviews and responses to industry related information requests or policy/procedure reviews.

For national level events, when a National Response Effort has been designated by an EEI member utility, the Company shall designate GLMA as the primary RMAG for LG&E and KU. (Please see Appendix 9.D for GLMA Group Governing Principles.)

9.2.2. Mutual Assistance Agreements

The Company has entered into several formal mutual assistance agreements which outline the general guidelines and principles the Company and mutual assistance partners will follow when engaged in mutual assistance efforts. The Director Electric Distribution and System Restoration shall be responsible for reviewing and approving all
proposed mutual assistance agreements, and for obtaining necessary reviews and
approvals from Legal, Regulatory, Supply Chain, and the Vice President Electric
Distribution.

9.2.2.1. Edison Electric Institute Mutual Assistance Agreement

EEI’s Suggested Governing Principles Covering Emergency Assistance Arrangements
Between Edison Electric Institute Member Companies (see Appendix 9.E) serve as
the electric industry’s foundation for describing and further developing RMAGs’
mutual aid systems and business processes. These principles were developed to
help EEI member utilities reduce and/or eliminate response delays and risks, and set
expectations respective to pre-event, event, and post event modes, liability, and
financial fairness. EEI routinely reviews and updates these principles from lessons
learned and or best practices within the electric industry. EEI also maintains data on
member companies who formally agree to the principles by signing their Mutual
Assistance Agreement (see Appendix 9.F).

Membership in the GLMA and MMA requires formal approval of the Edison Electric
Institute Mutual Assistance Agreement. The Company signed the EEI Mutual
Assistance ‘Short Form’ Agreement for LG&E and KU in 2006.

9.2.2.2. Southeast Electric Exchange Mutual Assistance Agreement

The SEE Mutual Assistance Committee developed, accepted, and is responsible for
maintaining Mutual Assistance Procedures and Guidelines (see Appendix 9.G) that
SEE members adhere to when engaged in mutual aid activities. LKE is a member of
the SEE Mutual Assistance Committee and contributed to the development of these
procedures.

LKE formally accepted (signed) SEE’s Statement of Understanding and Endorsement
(See Appendix 9.H) for LG&E and KU in 2005.

9.2.2.3. Pennsylvania Power and Light (PPL) Electric Utilities Mutual Assistance Agreement

The Company has entered into formal agreement with PPL Electric Utilities to follow
a standard set of mutual assistance guidelines when engaged in mutual assistance
with each other. The associated *Utility Services Agreement* is included in Appendix 9.I, and was signed by both Companies in October 2013. The principles of the agreement are based on the EEI Mutual Assistance Agreement.

### 9.2.2.4. Owensboro Municipal Utilities

The Company has entered into formal agreement with Owensboro Municipal Utilities to follow a standard set of mutual assistance guidelines when engaged in mutual assistance with each other. The associated *Mutual Aid Agreement* is included in Appendix 9.J. The principles of the agreement are based on the EEI Mutual Assistance Agreement, and were executed during 2013.

### 9.2.3. Regional Mutual Assistance Resource Requests

The Incident Commander, Work Planning Section Chief, Operations Section Chief or a designee shall be responsible for initiating/requesting a mutual assistance joint utilities conference call with the Company’s designated Primary RMAG whenever incremental resources are needed from the Company’s mutual assistance network. When making a request for resources, the designated requestor shall be prepared to provide the following information to the Primary RMAG:

- Number of workers (full time equivalents – FTE) needed by type;
  - Distribution Line Technicians
  - Transmission Line Technicians
  - Damage Assessors
  - Public Safety Responders
  - Vegetation Management Trimmers
  - Substation Technicians
  - Network Technicians

- Crew size specifications, if any;

- Equipment specifications, if any;
  - Bucket Truck
  - Material Handler
  - Digger Derrick
  - Light Duty Unit
  - Etc...

- Maximum traveling duration/distance; and,
9.2.2 Contractor, Union, or Non-Union requirements, if any.

If resource needs are satisfied by the Primary RMAG, then no additional resource requests shall be executed.

In the event the Primary RMAG cannot satisfy the resource needs of the Company, the Incident Commander, Work Planning Section Chief, or a designee shall request the primary RMAG to approach neighboring RMAGs to determine if additional assistance can be obtained through secondary member RMAGs. If resource needs cannot be satisfied through the Company’s Primary and Secondary member RMAGs, and all other resource options have been exercised, the Incident Commander shall be responsible for requesting the Vice President – Electric Distribution to declare a National Response Effort with the Edison Electric Institute, per EEI’s National Response Event Structure and Principles Covering Mutual Assistance Arrangements between Edison Electric Institute Member Companies (see NRE Playbook at the following link: http://nre.groupsite.com/uploads/files/x/000/0ad/491/NRE_Playbook_Sepemb er%202014%20updates%20ver%20x.pdf?1410788377).

9.2.4 Kentucky Cooperatives

On occasion, the Company has utilized resources from Kentucky Electric Cooperatives (KEC) to assist with responding to large outage events and associated emergencies. There are 24 electric distribution cooperatives across Kentucky.
**Electric Distribution**

**Emergency Preparedness and Response Plan**

**Section 9.2**

**Mutual Assistance**

Effective Date: 12/30/2014  
Version No. 1

### Distribution Cooperatives

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<th>HOME OFFICE</th>
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<tr>
<td>A</td>
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<td>X</td>
<td>West Kentucky RECC</td>
<td>Mayfield</td>
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KEC has designated a single point of contact for requesting resources from and providing assistance to the KEC.

Appendix 9.C contains contact information for Municipal and Cooperative mutual assistance partners.
9.3. Finance and Accounting

Budgeting and Forecasting and Electric Distribution Operations have developed business procedures to ensure adequate financial and accounting information and processes are in place to accurately account for and forecast expenditures associated with significant outage events or emergencies involving the electric delivery system.

9.3.1. Roles and Responsibilities

9.3.1.1. Finance Director – or their designee, shall report to the Work Planning Section Chief, and be primarily responsible for ensuring proper accounting systems and processes are in place to track and report on emergency preparedness and response costs associated with significant outage events or emergencies. This position shall also be responsible for:

- Provide financial support to the Incident Commander, Section Chiefs, and Officers as requested;
- Establish an accurate and timely reporting and communication process for establishing charge numbers, and providing cost estimates; and
- Accumulate preparedness and response charges, and provide post-storm financial reporting.

Appendix 10.0 contains names, titles, and contact information for designated Finance Directors.

9.3.2. Activation

9.3.2.1. Yellow Alert – The Work Planning Section Chief or their designee shall be responsible for notifying the Finance Director of any issued Yellow Alerts.

9.3.2.2. Red Alert – The Work Planning Section Chief or their designee shall be responsible for notifying the Finance Director of any issued Red Alerts.

9.3.3. Business Processes

9.3.3.1. Storm/Event Numbers – The Finance Director shall be responsible for working with Operations and Retail and developing policies and procedures respective to the provision of accounting numbers for the purpose of charging all costs associated with preparedness for or response to a significant outage event or emergency. The Finance Director or their designee shall be responsible for advising affected Operations Centers of established project numbers within the first 24 hours of an event.
9.3.3.2. **Event Estimates** – The Financial Director or their designee shall be responsible for developing standard accounting processes, modeling tools, and timelines for calculating and reporting preparedness and response costs for significant events.

9.3.4. **After Action Review** – The Financial Director shall be responsible for coordinating an After Action Review with key Budgeting and Forecasting organizations and the EPRT following all significant outage events or emergencies, to identify, develop, and implement process improvement opportunities respective to IT support.
9.4. Asset Information

Asset Information and the Emergency Preparedness and Response Team (EPRT) have developed business procedures to ensure critical facility data and geographical information are readily available when the Company is preparing for or responding to a significant outage event or emergency involving the electric distribution system.

9.4.1. Roles and Responsibilities

Asset Information Director — or their designee, shall report to the Work Planning Section Chief, and be responsible for ensuring facility maps (electronic and hard copy), data, and records technician resources are readily available to support operations personnel responding to significant outage events and emergencies. Appendix 10.0 contains contact information for Asset Information personnel.

9.4.2. Activation

9.4.2.1. Yellow Alert — The Work Planning Section Chief or their designee shall be responsible for notifying the Asset Information Director of any issued Yellow Alerts.

9.4.2.2. Red Alert — The Work Planning Section Chief or their designee shall be responsible for notifying the Asset Information Director of any issued Red Alerts.

9.4.3. Business Processes

9.4.3.1. Facility Records — After receiving notice of a Yellow or Red Alert, the Asset Information Director shall be responsible for:

- Working with the Operations Managers of affected operations areas to identify geographical and facility information needs and sources;
- Working with Information Technology to ensure needed facility information and reporting systems are available and operating properly;
- Working with Operations Managers to efficiently allocate available Facility Records Technicians to impacted areas to assist with producing prints, collecting facility information, and pulling together Work Packets during Level III and IV events;
- Assist with pulling together circuit prints as needed for damage assessment inspections and post restoration and repair sweeps; and,
- Executing business processes which ensure documented field changes are updated in the appropriate geographical and facility information systems.
9.4.4. **After Action Review** – The Asset Information Director shall be responsible for coordinating an After Action Review with key Information Technology organizations and affected Operations areas to identify, develop, and implement process improvement opportunities respective to Asset Information support during emergencies.
9.5. Information Technology and Systems

Information Technology (IT) and the Emergency Preparedness and Response Team (EPRT) have developed business procedures to ensure critical information technology systems and processes are available and properly functioning when the Company is preparing for or responding to a significant outage event or emergency involving the electric distribution system.

9.5.1. Roles and Responsibilities

IT Director – or their designee, shall report to the Work Planning Section Chief, and be responsible for serving as the primary conduit between the business and IT during significant outage events or emergencies on the electric distribution system, and helping to ensure critical information systems and processes are available and properly functioning during preparation for or response to these significant events. Appendix 10.0 contains contact information for key personnel in Information Technology.

9.5.2. Activation

9.5.2.1. Yellow Alert – The IT Director or their designee shall have overall responsibility for appropriately responding to Yellow Alert Levels issued by the Incident Commander or their designee, including communicating to appropriate key leadership roles within IT, and being available to assist with associated needs during the Company’s preparation for significant events.

9.5.2.2. Red Alert – The IT Director shall have overall responsibility for appropriately responding to Red Alert Levels issued by the Incident Commander or their designee, including communicating to appropriate key leadership roles within IT, and being available to assist with associated needs during the Company’s response to significant events.

9.5.3. Business Processes

9.5.3.1. IT Service Desk – After receiving notice of a Yellow or Red Alert, IT Director shall ensure the IT Service Desk is advised of the alert status and staffed adequately. The IT Service Desk shall be responsible for ensuring adequate IT Support Technicians are placed on duty or standby, in accordance with IT’s Responsibility Matrix. In some cases, IT Support Technicians shall be placed in key locations to work directly with end users. Additionally, the IT Service Desk should work with all necessary IT organizations and personnel to cease unnecessary maintenance, batch processing,
development, patch installations, etc... on critical information systems, whenever these procedures could place the availability of the critical systems at risk.

9.5.3.2. **Mobile Command Trailer(s)** - If a Mobile Command Center (MCC) is needed, the Incident Commander or the Operations Section Chief shall notify IT Support, who will work with the appropriate departments and personnel within IT to contact and assign the necessary personnel to assist Operations with deployment and technical setup of the MCC.

9.5.4. **After Action Review** – The IT Director shall be responsible for coordinating an After Action Review with key Information Technology organizations and the EPRT following all significant outage events or emergencies, to identify, develop, and implement process improvement opportunities respective to IT support during emergencies.
EPRP Appendix 1 Introduction
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<thead>
<tr>
<th>Position</th>
<th>Name</th>
<th>Title</th>
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<tr>
<td>Executive Sponsor</td>
<td>John Wolfe</td>
<td>VP Electric Distribution</td>
</tr>
<tr>
<td>Executive Sponsor</td>
<td>John Malloy</td>
<td>VP Customer Service</td>
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<tr>
<td>Executive Sponsor</td>
<td>Chris Whelan</td>
<td>Vice President Corporate Communications</td>
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<td>Executive Sponsor</td>
<td>Robert Conroy</td>
<td>Vice President State Regulation and Rates</td>
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<td>Executive Sponsor</td>
<td>Tom Jessee</td>
<td>Vice President Transmission</td>
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<tr>
<td>Information Officer</td>
<td>Brian Phillips</td>
<td>Director Brand Adv Cust &amp; Digitl Comm</td>
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<td>Natasha Collins</td>
<td>Director Media Relations</td>
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<tr>
<td>Incident Commander</td>
<td>Steve Woodworth</td>
<td>Director Electric Distribution &amp; System Restoration</td>
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<td>David Huff</td>
<td>Director Customer Energy Efficiency &amp; Smart Grid</td>
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<tr>
<td>Customer Experience Section Chief</td>
<td>Cheryl Bruner</td>
<td>Director Customer Service and Marketing</td>
</tr>
<tr>
<td>Customer Experience Section Chief</td>
<td>Debbie Leist</td>
<td>Director Revenue Integrity</td>
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<td>Logistics Section Chief</td>
<td>Butch Cockerill</td>
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<td>Mark Schmitt</td>
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<td>Amanda Chambers</td>
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**Reg Generation / Transmission**

**MANAGER - System Control Center**

**MANAGER - Transmission Reliability Performance & Standards**

**MANAGER - Transmission Line Services**

**MANAGER - Transmission Policy and Tariffs**

**MANAGER - Transmission Reliability and Compliance**

**WESTERN**

**BLUESTRASS**

**CENTRAL**

**MOUNTAIN & DOMINION POWER**

**LOUISVILLE GAS & ELECTRIC**
# Executive Officers
- Information Officer
- Safety Officer
- Incident Commander
- Operations Section Chief
- Customer Experience Section Chief
- Logistics Section Chief
- Work Planning Section Chief
- Emergency Preparedness Manager

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## Emergency Preparedness and Response Plan

### Review and Approval Schedule

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### Emergency Preparedness and Response Plan

Plan Review, Training, and Exercise Schedule

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R - Review Procedure; T - Train on Associated Emergency Processes; E - Exercise Emergency Processes
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### Plan Review, Training, and Exercise Schedule

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Attachment to Response to AG-1 Question No. 400(a)  
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Wolfe
EMERGENCY EXERCISE OBJECTIVES, DESCRIPTIONS, AND EXERCISE FORM

TITLE PAGE

EXECUTIVE SUMMARY

1. PURPOSE
2. MAJOR STRENGTHS
3. PRIMARY AREAS FOR IMPROVEMENT
4. CONCLUSION

EXERCISE OVERVIEW

1. EXERCISE NAME
2. EXERCISE DATE
3. SCOPE
4. PURPOSE
5. OBJECTIVES
6. SENARIO DESCRIPTION
7. PARTICIPATING GROUPS

IMPROVEMENT PLAN

| CORE CAPABILITY | Issue/Area for Improvement | Corrective Action | Responsible Part | Start Date/Completion Date |
### After Action Review

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#### What went well (list three):

1. ____________________________________________________________________________________
2. ____________________________________________________________________________________
3. ____________________________________________________________________________________

#### Things that did NOT go well (list three):

1. ____________________________________________________________________________________
2. ____________________________________________________________________________________
3. ____________________________________________________________________________________

#### Comments/Suggestions to Improve:

1. ____________________________________________________________________________________
2. ____________________________________________________________________________________
3. ____________________________________________________________________________________
4. ____________________________________________________________________________________
5. ____________________________________________________________________________________

Name: ___________________________ Role: ___________________________ Date: ___________________________

Please return Completed form(s) to the Emergency Planning & Preparedness Manager, Keith Alexander, via email at [email protected], or via house-mail (BOC I). Submitted forms will be reviewed by the Emergency Preparedness and Response Team for to identify and act on improvement opportunities.
EPRP Appendix 2 Emergency Notification Information
Internal Notification/
Emergency Response Guide

This is only a guide and does not take the place of any specialized training or official publications or communications containing governmental regulations and/or laws.
Mandatory/Immediate Incident Notification Procedures

In order to meet external safety and regulatory requirements, LG&E and KU corporate policy mandates that the following incidents be reported immediately to each of the following: LG&E, KU or ODP incident investigators, safety contacts and the Corporate Law Department. All parties must be notified as soon as practicable via direct telephone or face-to-face conversations. Voice mail and/or e-mail messages are not acceptable forms of notification. These incidents include any that involve:

- Death.
- Electrical shock.
- Burns requiring off-site medical attention.
- An injury requiring local EMS/helicopter transport.
- Exposure requiring extensive decontamination.
- An injury or fatality as a result of fire.
- Any public injury.
- Any incident with multiple injuries, regardless of extent.
- Any event requiring significant work stoppage.
- An event requiring an evacuation of a facility.
- A natural gas explosion.
- An unintentional ignition of natural gas.
- A fire at an LG&E, KU or ODP facility, where an outside fire service has been notified.
- A spill with a reportable amount, or if it is not known that the spill is less than a reportable amount.
- Electrical outages of 50,000 or more customers for one hour or more. — U.S. Dept. of Energy (DOE)
- Actual or suspected physical attacks that could impact electric power system adequacy or reliability, or vandalism which targets components of any security system. — DOE
- Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability. — DOE
- Electrical outages of 500 or more customers for four or more hours. — Kentucky Public Service Commission (KPSC)
• Natural gas outages of 40 or more customers for four or more hours.
• Where there is $25,000 in damage or theft. — KPSC
• Where there is $3,000 in damage or theft. — (Indiana) IURC
• Any incident requiring notification to the KPSC.
• Any incident requiring notification to the IURC.
• Any incident requiring notification to the USDOT.
• Any incident which, in the opinion of personnel on the scene, is significant.

**Sabotage Reporting**

- Employees and contract employees must report incidents of actual or suspected sabotage by calling the Corporate Security Control Center 24/7 at 502-627-2222.
- Sabotage is broadly defined as disturbances or unusual occurrences intended to cause failure, disruption or harm to the normal business activities, property or operations of LG&E, KU or ODP.
- Employees will be alerted when an incident has occurred somewhere in the company and advised to take appropriate actions, or they may call 866-370-7711 (toll free) or 502-627-4141 for information.

**Investigation Contacts**

Immediately contact Keith McBride, who has primary responsibility for all investigations. If he is unavailable, Corporate Law will direct one of the following to investigate:

- Brian Claypool
- Risk Management Services (primarily for theft and auto accidents).
- Corporate Law (accidents involving death, serious injury, fire, explosion or any significant incident).
- Contact Barbara Hawkins, Manager, Corporate Health and Safety, in the event of an OSHA investigation, or an incident — such as an employee injury or possible hazardous exposure — prompts further OSHA investigation.
- Contact Phil Noble regarding any fatality or newsworthy event for purposes of reporting under the company’s Crisis Management Policy.

**Media Contact**

Inform LG&E and KU Corporate Communications of any incident with the potential to receive media coverage or where media are present or expected to be present.
### Ky. PSC: Contact (Electric/Office Cell)
- Steve Kingsolver
- Jeff Moore
- Eric Bowman

### Ky. PSC: Contact (Gas/Office Personal Cell)
- Bill Aitken
- Jason Brangers
- Melissa Holbrook
- Steve Samples
- Joel Grugin
- Kimra Cole

Notification to the KPSC voice mailbox will **not** be considered proper notification.

### LG&E/KU Environmental Dept.
- Sherry Pryor
- Paul Puckett
- Roger Medina

Chem-trec 800-424-9300

### Environmental Regulatory Agencies
- **Ky. Dept. for Environmental Protection (if call forwards to KYDEM, be sure to make both notifications)**
  - 800-928-2380
- **Kentucky Division of Emergency Management (KyDEM, EHS ≥ RQ)**
  - 800-255-2587
- **National Response Center (Waterways, spec. PCBs, hazardous chemicals ≥ RQ)**
  - 800-424-8802
- **Indiana Dept. of Environmental Management**
  - 888-233-7745
- **Virginia Dept. of Emergency Management**
  - 800-468-8892
- **USEPA Region IV (KY.: PCBs ≥ 500 ppm or > 1#PCB)**
  - 404-562-8700
- **USEPA Region III (VA.: PCBs ≥ 500 ppm or > 1#PCB)**
  - 215-814-9016
- **USEPA Region V (IN.: PCBs ≥ 500 ppm or > 1#PCB)**
  - 312-353-2318

### U.S. Department of Transportation
- **Reporting Line**
  - 800-424-8802

### Indiana Utility Regulatory Commission
- **Contact Office Cell**
  - William Boyd

### Occupational Safety & Health
- **Ky. OSHA Division of Compliance Federal OSHA Hotline**
  - 502-564-3535
  - 800-321-6742
<table>
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<tr>
<td>Corp. Communications Dept.</td>
<td>502-627-2911</td>
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<tr>
<td>Corporate Law Dept.</td>
<td>502-627-3450</td>
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<td>502-627-3444 ¹</td>
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<tr>
<td>Jay Warren — Sr. Corporate Attorney</td>
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<td>Greg Cornett — Assoc. Gen. Counsel</td>
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<tr>
<td>Barbara Hawkins (Health &amp; Safety)</td>
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1) Mark urgent/high priority.
**KPSC Notification — Criteria**

Notifications must be made within two hours following incident discovery.

- Gas: Fire/explosion, unintentional ignition.
- Electric: Injury, shock or burn requiring medical treatment at a hospital.
- Gas or electric: Death or any injury that requires hospitalization (admitted overnight).
- Gas or electric: Damage or theft of property (over $25,000).
- Gas: Any newsworthy incident.
- Interruption of service: Electric, 500 customers; gas, 40 customers over four hours.

**KPSC Notification — Procedures**

- Energy Delivery: Notify Ken Sheridan, Keith McBride or Brian Claypool.
- Energy Services: Notify Doug Chin, Ken Sheridan, Keith McBride or Brian Claypool.
- Transmission: Notify Troy Bess, Doug Chin, Ken Sheridan, Keith McBride or Amanda Chambers.

In the event none of the above is available, Corporate Law is responsible for any regulatory notification. As required, Ken Sheridan, Keith McBride and Doug Chin are responsible for DOT notification.

**KPSC Outage Notification**

- KU/ODP — Donna Goodrich
- LG&E electric — Charlie Hudson
- LG&E natural gas — Brian Claypool

Notify Corporate Law about all official KPSC notifications.

**KOSHA Division of Compliance Notification — Criteria**

- Gas or electric: Death or hospitalizations (admitted overnight) involving three or more employees in the same event. Notification must be made within eight hours of the event or hospitalizations.
- Gas or electric: Amputations or hospitalizations involving less than three employees (admitted overnight). Notification must be made within 72 hours of the event or hospitalization.

**KOSHA Notification — Procedures**

- Energy Delivery: Notify Keith McBride or Ken Sheridan.
- Energy Services: Notify Keith McBride or Doug Chin.
- In the event McBride, Sheridan or Hosmer are unavailable, Corporate Law is responsible for KOSHA notification.

**U.S. Department of Transportation (Natural Gas Pipelines)**

Notice of the following shall be made to the USDOT by telephone “at the earliest practicable moment” followed by a written report within 30 days (obtain form from Corporate Law):

- An event that involves a release of gas from a pipeline AND one of the following:
  - a death or personal injury necessitating inpatient hospitalization; or
  - estimated property damage, including cost of gas loss, of $50,000 or more.
- An event that is significant in the judgment of the operator.

**Indiana Utility Regulatory Commission (Gas) Notification — Criteria**

(Appplies to LG&E underground natural gas storage fields in Indiana.)

**Incident Reports.** All incidents shall be reported to the IURC Pipeline Safety Division by telephone or electronic submission at the earliest practicable moment following discovery. This notification shall be followed by a written report upon request by the division within 20 days of the request.

An incident is defined as an event that:

- involves a release of gas from a pipeline, and
  - a death, or personal injury necessitating inpatient hospitalization; or
  - estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more;
- deemed significant by the operator, such as situations involving
  - media attention;
— high-profile locations;
— large evacuations; or
— the possibility of recurrence.
(Refer to 170 IAC 5-3 section 0.5(b)(6) and section 4; LG&E OM&I procedure Gathering Data for Part 191 Incident Reporting.)

**Indiana Underground Regulatory Commission (Gas) Notification — Procedures**

Notify Ken Sheridan, Keith McBride or Brian Claypool. They perform telephonic notification to the IURC. In the event none are available, Corporate Law is responsible for any regulatory notification. Corporate Law is responsible for filing follow up written reports. Peter Clyde should be informed of notifications made to the IURC and provided copies of written reports submitted. (Details are outlined in LG&E OM&I procedure GN-GD-001 Gathering Data for Part 191 Incident Reporting.)

**Critical Incident Reporting to PPL by LG&E and KU**

In the event of a serious safety or security incident at LG&E or KU, the notification protocol to PPL is as follows:

1. In the event of an employee or contractor injury or security incident that must be reported to a regulatory authority, contact:
   a. For employee or contractor injury — Barbara Hawkins
   b. Security incident — Phil Noble, or
   c. The respective delegate(s), and confirm that all internal notifications have been completed.*

2. PPL notification will be made by Barbara or Phil to the PPL Security Command Center. Notification timing may vary based on severity and circumstances of the incident, but notification to PPL should be made within 24 hours of reporting to a regulatory authority.

3. PPL Security Command Center personnel will then follow their internal notification protocol.

*The notification process to PPL involves no changes to current internal reporting processes.

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**Environmental: Spill/Release Response**

With transformer oil, petroleum product or hazardous chemical releases, take the following actions.

- Identify spilled substance, spill source and affected area.
- Call supervisor.
- Stop/contain the spill if trained or qualified to do so.
- Notify local emergency response contacts. Call 911 (or alternate number) if spill triggers Reportable Quantity (RQ), for example, a 25-gallon oil spill or any oil sheen on water, etc. Supervisor or dispatch must make a call if contacted within 15 minutes.
- Notify LG&E and KU environmental contacts and regulatory authorities. If contacted within 15 minutes, LG&E and KU environmental personnel will make additional required notifications. Otherwise, site personnel must make notifications.

**Spill Information Required**

When a potentially hazardous spill has occurred, the following information must be reported ASAP.

- Name/position of person reporting.
- Spill area description.
- Spill location, source and cause.
- Time of spill/incident.
- Material involved (such as PCB content).
- Corrective action taken.
- Estimated spill size/quantity released.

**Asbestos Emergency Guidelines**

An asbestos emergency is defined as an exposure to Asbestos Containing Materials (ACM) or other material that has not been tested and possibly contains asbestos materials. ACM can be found in:

- Floor and ceiling tiles.
- Thermal insulating materials.
- Brake and clutch assemblies.
- Pipe coating.
- Old control wiring insulation.
Post-Accident Drug/Alcohol Testing

Company policy requires post-accident testing when:
- Safety equipment/protection procedures are not followed.
- Employee behavior or actions could be a factor.
- Company vehicle is involved and there is potential for litigation.
- Vehicular accident occurs, and the employee is issued a moving-traffic violation citation.

49 CFR Part 382.303 — Post Accident Testing

A DOT drug and alcohol screening is required when a CDL driver is in a commercial vehicle involved in a vehicular accident, and
1. a fatality occurs.
2. a citation is received, and
   a. immediate medical treatment is required away from the scene, and/or
   b. one or more vehicles are towed.

Any fatality involving a commercial vehicle requires a DOT drug and alcohol screening.
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<tr>
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<th>Email</th>
<th>Position</th>
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<tbody>
<tr>
<td>Archer, Jamie</td>
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### VA SCC Notifications – Internal Reporting List

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EPRP Appendix 3 Incident Command Structure
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<td>Director Media Relations</td>
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<td>David Huff</td>
<td>Director Customer Energy Efficiency &amp; Smart Grid Strategy</td>
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<td>Director Electric System Restoration and Distribution</td>
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<td>Director Revenue Integrity</td>
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<td>Director Supply Chain</td>
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<td>Director Distribution-Operations</td>
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<td>Ken Sheridan</td>
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<td>Denise Montgomery</td>
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<td>Sanka Simon</td>
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<td>Tom Jessee</td>
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<td>Chris Balmer</td>
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<td>Richard Watson</td>
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<td>Mickey Grismer</td>
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Ensure all assigned resources are adequately trained and qualified to perform assigned tasks safely.

Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.

Ensure all assigned personnel have proper PPE to perform assigned roles and responsibilities.

Ensure personnel and resources are in place to perform on-scene handover from DLCC to Resource Management Rooms.

Ensure all hardware, software, office space, and communication systems are in place to conduct Section operations.

Ensure adequate availability of storm procurement cards.

Ensure all assigned personnel have proper PPE to perform assigned tasks safely.

Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.

Ensure personnel and resources are in place to perform on-scene handover from DLCC to Resource Management Rooms.

Ensure adequate availability of storm procurement cards.

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Ensure adequate availability of storm procurement cards.

Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.

Ensure personnel and resources are in place to perform on-scene handover from DLCC to Resource Management Rooms.

Ensure adequate availability of storm procurement cards.

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Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.

Ensure personnel and resources are in place to perform on-scene handover from DLCC to Resource Management Rooms.

Ensure adequate availability of storm procurement cards.

Establish Event Preparedness, Planning, and Response Call protocol.

Conduct monthly reviews of baseline resource rosters to ensure accuracy and availability for upload to resource database.

Establish, maintain, and train personnel on essential Logistics email addresses and phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.

Ensure all assigned resources are adequately trained and qualified to perform assigned tasks safely.

Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.

Ensure personnel and resources are in place to perform on-scene handover from DLCC to Resource Management Rooms.

Ensure all assigned personnel have proper PPE to perform assigned tasks safely.

Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.

Ensure personnel and resources are in place to perform on-scene handover from DLCC to Resource Management Rooms.

Ensure adequate availability of storm procurement cards.

Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.

Ensure personnel and resources are in place to perform on-scene handover from DLCC to Resource Management Rooms.

Establish and distribute StormResources email address and Work Planning phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.

Conduct routine periodic drills on storm roles and responsibilities to ensure adequate alignment with business needs, technology, and resources, and create embedding awareness.

Establish, maintain, and train personnel on essential Logistics email addresses and phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.

Conduct monthly reviews of baseline resource rosters to ensure accuracy and availability for upload to resource database.

Establish, maintain, and train personnel on essential Logistics email addresses and phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.

Conduct periodic reviews of strike level checklists to ensure adequate alignment with emergency restoration policies, procedures, and overall strategies.

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<table>
<thead>
<tr>
<th>Topic</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>Safety</td>
<td>1. Ensure all assigned Section resources have proper PPE to perform assigned roles and responsibilities.</td>
</tr>
<tr>
<td></td>
<td>2. Work with the designated Safety Officer to ensure adequate resources will be available to Passport off-system resources where needed.</td>
</tr>
<tr>
<td></td>
<td>3. Work with the designated Safety Officer to ensure adequate resources are available to conduct field observations and address safety issues for imminent or forecasted events.</td>
</tr>
<tr>
<td></td>
<td>4. Advise field and responding personnel of forecasted or approaching hazardous weather conditions.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Policies and Procedures</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alert designated Section leads of an approaching or forecasted event and place them on notice for potential call-out and Emergency Preparedness and Response Plan execution.</td>
<td></td>
</tr>
<tr>
<td>2. Request Resource Managers to update resource rosters to reflect available emergency response personnel and business partners.</td>
<td></td>
</tr>
<tr>
<td>5. Prepare Command Centers for activation.</td>
<td></td>
</tr>
<tr>
<td>6. Prepare to execute Mutual Aid business processes.</td>
<td></td>
</tr>
<tr>
<td>7. Confirm the availability of designated Staging Areas (Level III, IV event) for areas forecasted to have severe weather.</td>
<td></td>
</tr>
<tr>
<td>9. Execute weather alert External Communications (regulatory, media, political, emergency management, public, customers) business processes and technologies.</td>
<td></td>
</tr>
<tr>
<td>10. Alert all key Customer Experience leads (Critical Customers, Ombudsman Teams, Major Accounts, Call Centers, Business Offices) and prepare to execute associated business processes and technologies.</td>
<td></td>
</tr>
<tr>
<td>11. Prepare to execute Logistics (materials, housing, staging, meals, laundry, byproducts disposal) business processes.</td>
<td></td>
</tr>
<tr>
<td>12. Verify key information systems are available to monitor system status and help prioritize restoration efforts.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Resources</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Review key designated storm roles and responsibilities, and confirm availability of assigned personnel. Identify delegates where appropriate.</td>
<td></td>
</tr>
<tr>
<td>2. Confirm formal schedules are in place to adequately and effectively allocate/assign on-call, available, or assigned personnel/teams to the forecasted emergency or approaching event.</td>
<td></td>
</tr>
<tr>
<td>3. Review and update baseline resource rosters in the established Resource database.</td>
<td></td>
</tr>
<tr>
<td>4. Inventory and adjust storm material free-bins and kits.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Communications</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Conduct an Event Preparedness, Planning, and Response notification or call (when deemed necessary by the IC).</td>
<td></td>
</tr>
<tr>
<td>2. Participate or delegate participation in all scheduled Event Preparedness, Planning, and Response Calls.</td>
<td></td>
</tr>
<tr>
<td>3. Alert personnel with storm roles of an approaching or forecasted event and place them on notice for call-out execution.</td>
<td></td>
</tr>
<tr>
<td>4. Alert business partners (materials, services) of an approaching or forecasted event and place them on notice for call-out execution.</td>
<td></td>
</tr>
<tr>
<td>5. Verify adequate communications mediums are available for resources for forecasted or approaching emergency, including radios, cell phones, land lines, lap tops, and satellite phones.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Logistics</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Confirm that all hardware, software, office space, and communication systems are in place to conduct Section operations.</td>
<td></td>
</tr>
<tr>
<td>2. Confirm availability of predesignated staging areas.</td>
<td></td>
</tr>
<tr>
<td>3. Confirm availability of predesignated lodging areas.</td>
<td></td>
</tr>
<tr>
<td>4. Alert the Logistics Section Chief of command centers, staging area, and other physical areas that may be needed to respond to a forecasted or imminent event.</td>
<td></td>
</tr>
<tr>
<td>5. Alert Facilities or other designated personnel to set up command centers/resource management rooms.</td>
<td></td>
</tr>
<tr>
<td>6. Advise Security of staging areas, Operations Centers, or other areas where extended or supplemental security may be needed for forecasted or imminent events.</td>
<td></td>
</tr>
<tr>
<td>7. Open storm rooms for impacted areas.</td>
<td></td>
</tr>
</tbody>
</table>

2/2/2016 | Cells marked in this color were modified
<table>
<thead>
<tr>
<th>Topic</th>
<th>Task</th>
<th>Executive Officer</th>
<th>Safety Officer</th>
<th>Information Officer</th>
<th>Incident Command</th>
<th>Work Planning Section</th>
<th>Operations Section</th>
<th>Logistics Section</th>
<th>Customer Experience Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>Safety</td>
<td>Ensure all assigned Section resources have proper PPE to perform assigned roles and responsibilities.</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
</tr>
<tr>
<td>Policies and Procedures</td>
<td>Activate Incident Command storm roles and responsibilities.</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
</tr>
<tr>
<td>Resources</td>
<td>Continuously monitor resource management efforts to ensure adequate resources are assigned/available for Incident Command storm roles and responsibilities.</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
</tr>
<tr>
<td>Communications</td>
<td>Establish centralised phone numbers in designated Resource Management Rooms for responsibility areas.</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
</tr>
<tr>
<td>Logistics</td>
<td>Establish contracts/arrangements with local lodging providers.</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
<td>☑️</td>
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<td>☑️</td>
<td>☑️</td>
</tr>
</tbody>
</table>

2/2/2016 Cells marked in this color were modified
EPRP Appendix 4 Safety Information
### Capacitor Bank Fusing Chart

<table>
<thead>
<tr>
<th>Bank Size (KVA)</th>
<th>4.16kV</th>
<th>12.47kV</th>
<th>13.80kV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>LOSE</td>
<td>LOSE</td>
<td>LOSE</td>
</tr>
<tr>
<td>300</td>
<td>400A</td>
<td>200A</td>
<td>100A</td>
</tr>
<tr>
<td>450</td>
<td>500A</td>
<td>300A</td>
<td>200A</td>
</tr>
<tr>
<td>600</td>
<td>600A</td>
<td>400A</td>
<td>300A</td>
</tr>
<tr>
<td>900</td>
<td>800A</td>
<td>500A</td>
<td>400A</td>
</tr>
<tr>
<td>1200</td>
<td>1000A</td>
<td>700A</td>
<td>600A</td>
</tr>
<tr>
<td>1600</td>
<td>1200A</td>
<td>900A</td>
<td>800A</td>
</tr>
<tr>
<td>2100</td>
<td>1600A</td>
<td>1200A</td>
<td>1000A</td>
</tr>
<tr>
<td>2400</td>
<td>1800A</td>
<td>1400A</td>
<td>1200A</td>
</tr>
</tbody>
</table>

###UNDERGROUND FUSING CHART

<table>
<thead>
<tr>
<th>Transformer Size</th>
<th>2.5 kV, 100A or 4.16 kV, 200A or 12.47 kV, 300A (or 0 kA Only)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2 kV, 100A or 4.16 kV, 250A or 12.47 kV, 500A (or 0 kA Only)</td>
</tr>
<tr>
<td></td>
<td>1.5 kV, 150A or 4.16 kV, 200A or 12.47 kV, 300A (or 0 kA Only)</td>
</tr>
<tr>
<td></td>
<td>1 kV, 100A or 4.16 kV, 200A or 12.47 kV, 300A (or 0 kA Only)</td>
</tr>
<tr>
<td></td>
<td>0.75 kV, 75A or 4.16 kV, 150A or 12.47 kV, 200A (or 0 kA Only)</td>
</tr>
<tr>
<td></td>
<td>0.5 kV, 50A or 4.16 kV, 100A or 12.47 kV, 150A (or 0 kA Only)</td>
</tr>
<tr>
<td></td>
<td>0.25 kV, 25A or 4.16 kV, 75A or 12.47 kV, 100A (or 0 kA Only)</td>
</tr>
<tr>
<td></td>
<td>0 kV, 15A or 4.16 kV, 50A or 12.47 kV, 75A (or 0 kA Only)</td>
</tr>
<tr>
<td></td>
<td>NA</td>
</tr>
</tbody>
</table>
**Emergency Information Form**

Date/time ________________________________________________
Name ________________________________________________
Address ________________________________________________
City ____________________________________________________
State, ZIP ______________________________________________
Emergency contact ______________________________________

LG&E and KU wristband number ____________________________
Contractor name ________________________________________
Cell phone number for restoration updates (optional) ________

---

**Safety First! No Compromise!**
1. Pole ground must be connected to system metallic, transformer tank, primary bushing, and lightning arrestor ground, directly or indirectly. Typical grounding shown; other methods also acceptable.

2. Cutout to be mounted on side of equipment bracket furthest away from transformer. (See appendix 57-0933)

3. Transformer should be located in most convenient quadrant. When possible, the transformer should be placed in line with the conductors and on the side of the pole away from the house.

4. Wildlife protection should always be used. Also, poles should be kept clear of trees, brush, and underbrush around the transformer.

5. Pole placement of cutout to be used if necessary. Communications cables are present.

---

**Crossarm Construction**

---

**Transformer Dimensions**

<table>
<thead>
<tr>
<th>Item</th>
<th>A (IN)</th>
<th>B (IN)</th>
<th>C (IN/TYP)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>10.50</td>
<td>15.13</td>
<td>11.25</td>
</tr>
<tr>
<td></td>
<td>10.50</td>
<td>15.13</td>
<td>25.25</td>
</tr>
</tbody>
</table>

---

**Electric Design And Construction Standards**
Contents

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Overview

The primary objective of LG&E and KU is the safe, quick and orderly restoration of electric power to customers. We appreciate your help and are committed to ensuring you have the safest work environment possible.

This reference manual will provide you with the following:

- Emergency procedures
- Job briefing guidelines
- Guidelines regarding traffic control on the roadway and at the staging site
- Key elements of our distribution system
- A variety of procedures that you may perform during restoration efforts
- Basic environmental guidelines for restoration
- A list of tools, materials, equipment, PPE and other miscellaneous items that you will need to bring to the site and what the company may provide
- Safety procedures
  - LOTO (Lock Out/Tag Out)
  - Grounding
  - PPE (Personal Protective Equipment)
Energy Delivery

Safety Mission Statement

**No Compromise!**

Ensure, without compromise, that safety excellence is the core expectation of business operations, and that management and employees are responsible and accountable for a safe work environment.

**Values that support our mission statement**

**Communication.** We expect management, employees and business partners to discuss safety issues and share information openly, freely and constructively. Health and safety must be given the highest priority by all workers at all times. No doubt can be left in the mind of any individual that the company is committed to, and will not compromise, the safety or health of any employee or business partner.

**Commitment.** Management is steadfast in its commitment that safety comes first and will ensure that health and safety are engrained in business planning and performance improvement activities throughout the company. We will communicate in unequivocal terms, to each and every worker, that nothing is more important than safety.

**Accountability.** Management, employees and business partners will be held accountable for health and safety performance. All personnel must understand and apply health and safety procedures at all times, while maintaining exemplary customer service. All of us are responsible for our own safety, as well as the safety of those around us.

**Ownership.** We have adopted a *No Compromise* philosophy that requires the safety and well-being of our work force to come before all else. We will maintain high operating and business safety standards. We will establish challenging goals and measure performance to continually improve health and safety results that contribute to safety excellence as a core value for business success.
General Guidelines

Safety, including your personal well-being, is the first consideration for each and every job.

- Don't work beyond your limitations.
- If you need rest, stop working.
- If you need help, contact your lead person.
- If you are unsure about the task at hand, don't continue working.
- If you are assigned work that you are not qualified to do or you feel uncomfortable performing, just say "no!"
- You must meet or exceed all applicable OSHA safety standards and your organization's safety rules.

Our philosophy, when it comes to safety, is...

No Compromise!
General Information

- Each person is required to fill out an emergency information form upon arrival.
- Each contractor also must undergo safety passport training before beginning work. Upon completion of the training, you will receive a wristband to indicate you have been certified according to our safety standards.
- You must wear the wristband at all times (24/7) while working for LG&E and KU. It identifies you as having been safety certified, and as an authorized contractor to the public and to food and lodging vendors. If one is lost or comes off, notify your lead person immediately.

Time
- Each lead person/supervisor must fill out a time sheet/crew sheet. Complete all fields. Please include the name and contact number of your general foreman, safety person or lead person on site.

Staging Areas
- Your LG&E and KU lead person will provide you the location information.
- We make every attempt to control access to the site, so always wear your wristband.
- Park only in designated areas and follow all traffic control devices.
- Always drive slowly inside the staging areas due to the high number of pedestrians, delivery vehicles and staff needed to support the staging area.
- For safety purposes, back into a parking space upon arrival to avoid backing out.
- If you must back, always use a spotter.

Job Briefings
Documented job briefings are required by our state regulatory agency — the Kentucky Public Service Commission.
- Start every job, regardless of how small, with a job briefing.
- Every person working on a job must document that he or she participated in the job briefing by signing the sheet.
- You are required to retain the job briefing form for 30 days.
- If situations change during the course of a job, another job briefing is required.
- Always note the county and the location of your work on the briefing, in the event you need to call 911.

Lead Person/BirdDog
A bird dog is a qualified lead person and is usually a company employee. However, depending on the magnitude of the event, it could be a qualified resident business partner. The roles of this person are to:
- serve as the contact point for the company;
- get you to your job site;
answer any questions;
- request and release clearances;
- provide information; and
- process work orders and coordinate materials for jobs.

### Required PPE

LG&E and KU require you to wear certain PPE in order to work for the companies. You must have these items before you can begin work.

*If your policies differ from those listed here, please contact an LG&E or KU safety representative.*

- **Hard hat** — Make sure the hat meets safety standards.
- **Safety glasses** — Have ANSI Z87.1 clear and tinted.
- **Overshoes** — These are highly recommended, but they are not required.
- **Clothing** — Long-sleeve flame-resistant (FR) shirts, with a minimum of eight calories protection, are required. This can be achieved by layering a FR undershirt and outer shirt to achieve the eight-calorie minimum. Pants must be an eight-calorie minimum as well. Rain suits that will be worn in hot work situations must also be FR-rated.
- **Climbing gear** — Wear appropriate belt and climbers with properly sharpened gaffs.
- **Fall protection** — Wear appropriate fall protection devices for the work being performed, including harnesses for work from aerial platforms.
- **Chaps** — When using a chainsaw on the ground, wear chaps along with proper hearing and eye protection.
- **Cover-up material** — Have an adequate amount.
- **Gloves** — Gloves suitable for the work being performed must be worn. Rubber gloves and sleeves (Class 2) are required and must be worn together when:
  - Performing work on 600 volts and above while working within five feet of energized line;
  - Opening and closing or disconnecting fuses with a stick, other than a tested extendo, from the ground;
  - Installing or removing grounds;
  - Testing for primary voltage with a voltage detector with an eight-foot stick, and
  - Testing voltage on a new transformer.
  Low-voltage gloves (Class 0) must be used while working on 50 to 600 volts.

### Work Zone Safety

Proper work zones must always be established and managed to ensure the safety of workers as well as the public. Follow these basic rules.

- Place work signs on both sides of the work zone. The distance and locations should be determined by road conditions, traffic and visibility.
General Information

- Always use your vehicle's emergency fl ashers or strobes while working on the road or shoulder.
- Utilize cones to control and direct traffic and barricade the public from the work zone.
- Use certified flaggers when necessary.
- Flags are a temporary traffic signaling device; paddles should be used as quickly as they can be made available.
- When working within 15 feet of a roadway, wear a high-visibility Class II or Class III vest.
- Always control the public’s access to the work area.

Tree Work
We will make every effort to have adequate tree crews available to assist you; however, you may have to occasionally trim, fell or clear a tree. When you do:
- Chaps are required when using a chainsaw on the ground.
- Always evaluate the situation before cutting a tree.
- When felling a tree, always clear and identify your escape route.
- Use care and always determine the possible load created by the tree being cut.

Lock Out/Tag Out (LOTO)
- All work clearances will be requested and released through the Distribution Control Center by the lead person in charge of the job site.
- Hold cards must be placed on the energy source devices; each opened device will have a hold card attached.
- Caution cards will be used in one-shot situations.
- Once repairs are completed, your lead person will call the Distribution Control Center to release clearance and get permission to energize the line.
- In addition to these minimum requirements, you must also follow your company’s LOTO requirements.

Grounding Equipment
The following equipment should be used for grounding purposes on our systems.
- Class 2 rubber gloves and sleeves;
- voltage detector;
- eight-foot shotgun stick; and
- grounding cluster ring (when using equipotential grounding).
- LG&E
  - #2/0 copper grounds for the Distribution system.
• KU  
  — #2 copper grounds for the Distribution system.  
  — #2/0 copper grounds for the Transmission system.

Remember: If It’s Not Grounded; It’s Not Dead!

Grounding Methods
• Equipotential and bracket grounding methods are acceptable while working on the LG&E and KU systems. Use caution at all time while grounding.
• Place grounds as close to the work area as possible.
• Eliminate all sources of backfeed inside the bracket-grounded area by opening the transformer fuses, taplines, or fuses or by pulling meters.
• Watch out for secondary tie-breakers and remove them if possible (LG&E territory only).

Grounding Safety and Forestry Management
Line techs who work with or near tree trimmers should use special caution. They may be working under LOTO and grounds. You may be asked to ground for them or show them the location of grounds. Be sure to communicate effectively, and help ensure their safety.

Line Voltages
You will find these voltages on the LG&E and KU system.
• 34.5 kv / 22 kv / 13.8 kv delta
• 12,470 volts phase to phase / 7,200 volts phase to ground
• 4,160 volts phase to phase / 2,400 volts phase to ground

Secondary Voltages
• 120 / 240  
• 120 / 208  
• 240 / 480  
• 277 / 480

In LG&E territory, some delta banks are straight 240. (Watch out for triplex providing three-phase 240 volts.)

The Customer’s Property
Be extremely mindful of the impression you leave on customers as you go about restoration work.
• Please be respectful of customers’ property.
• Climb when safe and possible to avoid damage to yards and driveways.
• Document with your lead person when trucks are taken off the road in the event
General Information

- If you damage a customer's property, tell your lead person so the proper documentation can be filled out and repairs can be made.

Customer or Media Requests

During emergency situations, LG&E and KU constantly gather, verify and process information to share with the public through numerous media channels. It is imperative all messages be consistent and accurate. Consequently, all media information must be provided by the LG&E and KU Communications Department. If you are approached by a media person at the work site, professionally and politely direct the individual to your LG&E and KU lead person who can provide him or her with the appropriate contact information. Or, you can refer the person to the Communications Department at 502-627-4999. Do not attempt to address media questions on your own.

Environmental Compliance

Notify your lead person immediately upon discovering transformer oil spills, hydraulic oil spills, etc. Or, immediately contact LG&E and KU Environmental Affairs at 502-627-4512 (office) or 502-558-4464 (cell).

Incident Reporting

- An incident involving an employee, contractor, motor vehicle or property damage should be reported immediately to your LG&E and KU lead person.
- Make sure you are always aware of the county and your location in case you need to call 911!

Safety Communications

- Communication is critical during a major outage event.
- We will utilize numerous avenues to ensure all pertinent safety information is made available to you, our business partners.
- Daily safety bulletins will be posted at staging areas and included in work packets.
- Safety conference calls may be held daily with key personnel. (Notification will be made when these are implemented.) These calls are intended to provide your company representative with important safety information, including incident review, outage numbers and procedural updates.

  Conference call protocol — Due to the large number of participants on conference calls, it can be difficult for everyone to clearly hear the messages. We request that all callers mute their phones to prevent interruptions, unnecessary background noise or disruptions to the communication process. These calls are formatted to be one-way communication. If you have questions, please call the Safety Report Line at 502-627-3061 and leave a short message and call-back number. You will be contacted before

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NOTES:

I. Fuse ratings are for S&C Positrol Fuse Links "QR" Speed -- TCC No. 166-6 except those marked with an asterisk (*) which are Southern States type "F" links.

II. See note II. Page A-4-13.0 for proper fusing of three phase banks utilizing two transformers.
the next conference call.

**Safety Concerns or Issues**

If you have safety concerns, you can report them anonymously or leave a contact name for a response on the Safety Report Line (502-627-3061). All reports will be reviewed and addressed in a timely manner.

**Restoration Conclusion**

At the end of the restoration effort, please ensure you wrap up your work appropriately.
- Complete and submit all time information to the appropriate person.
- Return any work packet material to your LG&E and KU lead person.
- Return all material to the site designated by your LG&E and KU lead person.
- Return to your LG&E and KU lead person all tools and equipment we provided.

**Travel Tips For The Road Home**

- Make sure your vehicle is ready to travel; windshield clean and clear; mirrors clean and adjusted correctly; lights clean and working.
- Complete your DOT pre-trip form.
- Ensure your drivers are rested and alert.

---

**Table of Fuse Ratings**

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<thead>
<tr>
<th>SINGLE PHASE</th>
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**NOTES:**

I. Fuse ratings are for S&C Postrel Fuse Links "QR" Speed -- TCC No.166-6

II. Three phase banks utilizing only two transformers cannot be fused according to the table above and are to be fused as follows:

**OPEN Y -- OPEN DELTA, OR OPEN Y -- OPEN Y**
Fuse each transformer the same as in single phase installations.

**OPEN DELTA -- OPEN DELTA, OR OPEN DELTA -- OPEN Y**
Fuse outside leads the same as in single phase installations. Fuse the common lead with the next fuse size larger than the total of 3/4 of the smaller outside fuse rating and the larger outside fuse rating. For example - Given a 10 KVA 7200V transformer and a 50 KVA 7200V transformer to be connected open delta on the primary side: Fuse the 10 KVA transformer with a 5 amp fuse, the 50 KVA with a 20 amp fuse and the common lead with a 25 amp fuse (next size larger than (3/4)*5+20=23.75).
Thanks for your help. As you travel to your home, please remember — when it comes to your safety…

No Compromise!
Transformer should be located in most convenient quadrant. Cutout/arrester bracket to follow transformer location by 90 degrees.
### POLE SETTING DEPTHS

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<td>60</td>
<td>8</td>
</tr>
<tr>
<td>65</td>
<td>8 1/2</td>
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**NOTE:**

1. These depths shall be used for all classes of poles.
2. In soft or marshy ground, set poles deeper as required and back fill with crushed rock or gravel, but do not bank. See standard drawing 1-21.0
3. On slopes pole depth shall be measured on downhill side.
NOTE:
When the pole is installed near a street curb or other traveled ways, the ground
wire should be rotated to one of the quadrants away from traffic.

CAUTION
GROUND WIRE WHICH ARE
ATTACHED TO POLES BEING
SET IN OR NEAR ENERGIZED
LINES SHALL BE COILED AND
TEMPORARILY SECURED TO
POLE AT THE GROUND LINE
AND NOT EXTENDED UP THE
POLE UNTIL SETTING IS COM-
PLETED. BEFORE REMOVAL
OF POLES THAT ARE EQUIPPED
WITH GROUND WIRES, SUCH
WIRES MUST BE REMOVED.

APPLICATION NOTE: THIS TYPE OF GROUND TO BE
INSTALLED ON EVERY NEW POLE.

Ground wire must be repaired or
replaced when broken or damaged.
ALUMAFORM DEADEND ASSEMBLY
Catalog # HO-GEA-86-EB-3CA-CLK
KU ITEM # 010100
HUGHES BROTHERS DEADEND ASSEMBLY
2890-C
KU ITEM # 010101

Note: Mounts to pole with #6 hardware. Brackets not required.

Note: 2890-C comes complete with all Mounting Hardware including Braces.

NOTE:
1) Install insulator in all distribution guys.
2) On any transmission or distribution guy in conflict with conductor, strain insulator is to be installed below the level of the lowest electrical conductor.

NOTE: In case of joint use, Install Strain Insulator At Least 30 inches Vertical Distance Above Communication Facilities.

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.
PREASSEMBLED DEADENDS
FOR 397.5 ACSR & 795 AAC
Scale: Drawing Number
A-1-14.3

DISTRIBUTION DOWN GUY INSTALLATION
SCALE 1",=1'-0"
DRAWING NO.
A-1-15.0
Independent Hold Card (IHC) Program

Distribution Substation

Effective Date 12/16/2013
Independent Hold Card Program

Independent Hold Cards

During significant events on the Electric Distribution system, when large volumes of outage events and resource levels inundate Restoration Coordinators and saturate dedicated radio channels, the Distribution Control Center (DCC) and Operations Sections (OS) may elect to transfer control of all aspects of energy isolation and control procedures to qualified and approved personnel working on (operating, maintenance, repair, and construction) the electric distribution system.

Formal Transfer of Authority

Upon electing to transfer hold card authority, the appropriate DCC and OS leaders shall complete the Independent Hold Card Authorization Form (See Appendix, page 26) before granting permission to operate the electric distribution system under independent/individual clearance.

The DCC and OS shall determine the scope of the transfer (Company, Operations Center, Geographical Area, Substation, or Circuit), and establish the effective date and time when the Operations Section can safely assume independent hold card responsibilities. The scope shall be limited to areas where there is no possible back feed from a source outside the defined scope area.

Lead personnel shall formally authorize transfer in accordance with Independent Hold Card Authority Matrix (See Appendix A, page 27).

Upon formally transferring authority, the OS shall be responsible for communicating the transfer effective date(s) and time(s) to affected field personnel. The DCC shall be responsible for communicating the transfer to their personnel.

Each OS shall be responsible for designating qualified personnel and maintaining a separate LO/TO provider list for this purpose.

The OS shall be responsible for enforcing the requirement that qualified personnel do not operate isolation devices containing active hold cards, previously assigned a number and under control of the DCC, without receiving permission from the DCC.

Qualified personnel authorized to assume hold card responsibilities shall adhere to established lockout/tagout procedures when opening and closing devices on the electric distribution system, including:

- Conduct job briefing with all personnel working behind the isolation device(s);
- Apply hold cards in accordance with established procedures, under the authorized qualified person;
Independent Hold Card Program

- Document pertinent hold card information on the Independent Hold Card Log (See Appendix A, page 28);
- Confirm all personnel working under hold cards are in the clear and accounted for prior to operating an energy isolation device;

The DCC shall continue to be responsible for opening and closing devices in the System Tracking Application, to confirm customer counts are accurate.

- Qualified personnel opening energy isolation devices on the electric distribution system shall notify the DCC when opening devices to confirm customer counts stay accurate in the System Tracking Application.
- Qualified personnel needing to close isolation devices on the distribution system shall notify the DCC, immediately after closing the device in the field.

The DCC shall be responsible for confirming that field personnel requesting clearance from the Distribution Control Center are referred to the OS and made aware of the Independent Hold Card scope.

Revocation of Authority

Throughout the period in which Independent Hold Card Programs are in place, the DCC and OS shall evaluate the ability to revoke independent hold card authority, and transfer responsibility for hold cards back to the DCC. When an optimum time is identified and agreed upon, appropriate lead personnel shall document the transfer through completion of the revocation dates and signature lines on the Independent Hold Card Authorization Form.

Control of the Lockout/Tagout processes shall be transferred back to DCC upon formal completion and dissemination of the revocation effective date and time to affected personnel by the OS. Typically, all independent hold cards should be removed and all customers should be restored, prior to the DCC and OS formally transferring hold card authority back to the DCC. In the event formal transfer is deemed necessary prior to the completion of restoration work, all authorized qualified personnel still working behind independent hold cards shall be required to establish their hold cards with the DCC prior to operating an energy isolation device.
Independent Hold Card Program

Energy Delivery Implementation Procedures

- System Wide IHCP confirmed by IHCP Authorization Form Initiated by the DCC Director.
- System Wide IHCP confirmed by Incident Commander & Section Chiefs.
- System Wide IHCP confirmed by Operations Section Chief(s) and/or Director.
- IHCP Authorization Form Initiated by the DCC Director.
- IHCP Authorization Form Initiated by the DCC Team Leader.

Field Crews

- Qualified Lead Persons establish energy isolation and control under own clearance, logs hold cards.
- Qualified Lead Person notifies DCC to facilitate customer count updates and ERTs.
- IHCP Authorization Form Initiated by the DCC Director.
- IHCP Authorization Form Initiated by the DCC Team Leader.

Technical Training

- IHCP Authorization Form Initiated by the DCC Director.
- IHCP Authorization Form Initiated by the DCC Team Leader.

Operations Section

- IHCP Authorization Form Initiated by the DCC Director.
- IHCP Authorization Form Initiated by the DCC Team Leader.

Distribution Control

- IHCP Authorization Form Initiated by the DCC Director.
- IHCP Authorization Form Initiated by the DCC Team Leader.

Implementation Procedures

- System Wide IHCP confirmed by IHCP Authorization FormInitiated by the DCC Director.
- System Wide IHCP confirmed by Incident Commander & Section Chiefs.
- System Wide IHCP confirmed by Operations Section Chief(s) and/or Director.
- IHCP Authorization Form Initiated by the DCC Director.
- IHCP Authorization Form Initiated by the DCC Team Leader.
Independent Hold Card Program

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## Independent Hold Card Program

### Energy Delivery

#### Electric Distribution

#### Independent Hold Card Authority Matrix

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<td>Safety</td>
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<td>Safety Specialist</td>
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Independent Hold Card Program

<table>
<thead>
<tr>
<th>Bull Dog/Bird Dog Name:</th>
<th>Storm Date:</th>
</tr>
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<tbody>
<tr>
<td>Card #</td>
<td>Installed Date &amp; Time</td>
</tr>
<tr>
<td>EX. JB-1</td>
<td>1/30/2009 8:00</td>
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# Electric Distribution

## Emergency Preparedness and Response Plan

<table>
<thead>
<tr>
<th>Effective Date: 9/30/2014</th>
<th>Version No. 1</th>
</tr>
</thead>
</table>

**Appendix 5**

Communications Information

---

**EPRP Appendix 5 Communications Information**
### LG&E KU Emergency Preparations and Response Call Agenda

#### Call Details
- **Date:**
- **Time:** 12:00:00 AM
- **Phone:** 1 (877) 411-9748
- **Access Code:** 4377288
- **Moderator Code:** 7967

#### Next Call Details
- **Date:**
- **Time:**
- **Phone:** 1 (877) 411-9748
- **Access Code:** 4377288
- **Moderator Code:** 7967

### Incident Command Roles

<table>
<thead>
<tr>
<th>Role</th>
<th>Thompson, Paul</th>
<th>Bellar, Lonnie</th>
<th>Wolfe, John</th>
<th>Malloy, John</th>
<th>Siemens, George</th>
<th>Conroy, Robert</th>
<th>Whelan, Chris</th>
<th>Wolfe, John</th>
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#### Role Call

<table>
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<tr>
<th>Executive Officer</th>
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<tbody>
<tr>
<td>Bellar, Lonnie</td>
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<td>Wolfe, John</td>
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<tr>
<td>Malloy, John</td>
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<td>Siemens, George</td>
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<td>Conroy, Robert</td>
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<td>Whelan, Chris</td>
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<td>Wolfe, John</td>
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</table>

<table>
<thead>
<tr>
<th>Safety Officer</th>
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<tbody>
<tr>
<td>Sheridan, Ken</td>
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<td>Chambers, Amanda</td>
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<table>
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<tr>
<th>Communications Officer</th>
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<tbody>
<tr>
<td>Collins, Natasha</td>
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<td>Phillips, Brian</td>
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<thead>
<tr>
<th>Incident Commander</th>
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<tr>
<td>Woodworth, Steve</td>
</tr>
<tr>
<td>Huff, David</td>
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<table>
<thead>
<tr>
<th>Operations Section Chief</th>
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<tbody>
<tr>
<td>McFarland, Beth</td>
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<tr>
<td>Simon, Denise</td>
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<td>Steinmetz, Keith</td>
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<table>
<thead>
<tr>
<th>Customer Experience Section Chief</th>
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</thead>
<tbody>
<tr>
<td>Bruner, Cheryl</td>
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<tr>
<td>Leist, Debbie</td>
</tr>
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<td>Alexander, Keith</td>
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<table>
<thead>
<tr>
<th>Logistics Section Chief</th>
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</thead>
<tbody>
<tr>
<td>Cockrell, Butch</td>
</tr>
<tr>
<td>Schmitt, Mark</td>
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</table>

<table>
<thead>
<tr>
<th>Work Planning Section Chief</th>
</tr>
</thead>
<tbody>
<tr>
<td>Montgomery, Shannon</td>
</tr>
<tr>
<td>Simon, Denise</td>
</tr>
</tbody>
</table>

### Other:

- Work Planning Section Chief
- Logistics Section Chief
- Customer Experience Section Chief
- Operations Section Chief
- Incident Commander
- Safety Officer
- Communications Officer
- Executive Officer
# Yellow and Red Alert Conference Call Checklist (0-24 hours)

<table>
<thead>
<tr>
<th>Incident Command Position</th>
<th>Agenda Item</th>
<th>Checklist</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Incident Commander</strong></td>
<td>Role Call</td>
<td>Confirm IC structure is in place; identify personnel and schedules for each Section Chief role; assess personnel needs for all sections.</td>
</tr>
<tr>
<td></td>
<td>Weather/Emergency Condition Report</td>
<td>Assess weather conditions and system threats for service areas</td>
</tr>
<tr>
<td></td>
<td>Industry Status</td>
<td>Assess Industry status to determine potential impacts to resource availability</td>
</tr>
<tr>
<td></td>
<td>Command Centers</td>
<td>Establish location of command center(s); establish contact information</td>
</tr>
<tr>
<td><strong>Safety</strong></td>
<td>Public Safety (PSRT)</td>
<td>Provide status of PSRT efforts; number of downed wires, wire walkers, service crews, etc...</td>
</tr>
<tr>
<td></td>
<td>Worker Safety</td>
<td>Provide safety status and expectations - safe to work?, work hours, safety considerations, incident or near miss reviews, etc...</td>
</tr>
<tr>
<td></td>
<td>Passporting</td>
<td>Establish arrangements for passporting off system resources.</td>
</tr>
<tr>
<td></td>
<td>Independent Hold Card Status</td>
<td>Establish whether hold card procedures will be decentralized, or if the DCC will continue to issue hold cards.</td>
</tr>
<tr>
<td><strong>Operations Section</strong></td>
<td>Customer Outages/Events</td>
<td>Provide outage counts, events, wire downs, and any other key information that is available (broken poles, etc...)</td>
</tr>
<tr>
<td></td>
<td>Operations Areas Impacts</td>
<td>Provide overview of impact areas, by Operations Centers.</td>
</tr>
<tr>
<td></td>
<td>Damage Assessment Status</td>
<td>Provide damage assessment status; establish DA duration and resource needs.</td>
</tr>
<tr>
<td></td>
<td>Work Assignment Status</td>
<td>Establish whether the DCC or Resource Rooms will be assigning outage events.</td>
</tr>
<tr>
<td></td>
<td>Transmission System Status</td>
<td>Provide an update on the transmission system.</td>
</tr>
<tr>
<td></td>
<td>Local Estimated Restoration Durations</td>
<td>Provide an Estimated Restoration Duration by Operations Center</td>
</tr>
<tr>
<td></td>
<td>Vegetation Resources</td>
<td>Confirm that adequate vegetation resources are available and assigned to appropriate areas.</td>
</tr>
<tr>
<td><strong>Logistics Section</strong></td>
<td>Hotels</td>
<td>Discuss needs and availability; alternatives for deltas.</td>
</tr>
<tr>
<td></td>
<td>Meals</td>
<td>Discuss needs and availability; alternatives for deltas.</td>
</tr>
<tr>
<td></td>
<td>Staging Areas</td>
<td>Verify condition and usability of planned staging areas; determine if alternative staging locations are needed.</td>
</tr>
<tr>
<td></td>
<td>Fuel</td>
<td>Discuss needs and availability; alternatives for deltas.</td>
</tr>
<tr>
<td></td>
<td>Materials</td>
<td>Discuss needs and availability; alternatives for deltas.</td>
</tr>
<tr>
<td></td>
<td>Security</td>
<td>Provide status of security needs, assignments, threats.</td>
</tr>
<tr>
<td></td>
<td>Fleet</td>
<td>Determine if incremental equipment or vehicles are needed</td>
</tr>
<tr>
<td><strong>Customer Experience Section</strong></td>
<td>Emergency Management Outreach</td>
<td>Discuss Emergency Management Outreach status/plans/strategy; determine if any emergency declarations have been established</td>
</tr>
<tr>
<td></td>
<td>Customer Communications</td>
<td>Discuss call center volumes, customer environment, communications strategy</td>
</tr>
<tr>
<td></td>
<td>Walk In Centers</td>
<td>Discuss staffing/opening of walk in centers</td>
</tr>
<tr>
<td></td>
<td>Key and Critical Customers</td>
<td>Establish status of Ombudsman team; assess level of communications with key and critical customers</td>
</tr>
<tr>
<td><strong>Work Planning Section</strong></td>
<td>Resource Status</td>
<td>Provide resource counts - needed, assigned, available, secured off system (mutual aid/business partners), in transit, released</td>
</tr>
<tr>
<td></td>
<td>Check-In</td>
<td>Establish areas where resources are staging, and discuss resource needs/processes for checking in off system resources.</td>
</tr>
<tr>
<td></td>
<td>Asset Information Systems</td>
<td>Ensure all information systems are available</td>
</tr>
<tr>
<td></td>
<td>Financial Tracking</td>
<td>Identify financial resource for tracking resources; ensure information flow is as needed.</td>
</tr>
<tr>
<td><strong>Communications</strong></td>
<td>Media</td>
<td>Discuss media requests, communications strategy, and specific information to be provided</td>
</tr>
<tr>
<td></td>
<td>Internal Communications</td>
<td>Discuss content and medium for information to be shared internally</td>
</tr>
<tr>
<td></td>
<td>External Communications</td>
<td>Discuss details of information to be shared, and establish point(s) of contact</td>
</tr>
<tr>
<td><strong>Executives/Officers</strong></td>
<td>Regulatory Communications</td>
<td>Discuss details of information to be shared, and establish point(s) of contact</td>
</tr>
<tr>
<td></td>
<td>Daily Storm Goals</td>
<td>Discuss high level response goals - safety, resources, customers, communications</td>
</tr>
<tr>
<td>Incident Command Position</td>
<td>Agenda Item</td>
<td>Checklist Description</td>
</tr>
<tr>
<td>---------------------------</td>
<td>-------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Incident Commander</td>
<td>Role Call</td>
<td>Conduct role call, and determine availability of lead positions in IC structure; assess personnel needs of all sections</td>
</tr>
<tr>
<td></td>
<td>Weather/Emergency Threat Report</td>
<td>Review status of weather/emergency threat(s) on electric distribution system</td>
</tr>
<tr>
<td></td>
<td>Industry Status</td>
<td>Assess Industry status to evaluate the level of mutual aid that may be needed</td>
</tr>
<tr>
<td></td>
<td>Mutual Assistance</td>
<td>Determine if mutual assistance calls should be conducted</td>
</tr>
<tr>
<td>Safety</td>
<td>Public Safety (PSRT)</td>
<td>Provide status of PSRT alert and preparedness efforts</td>
</tr>
<tr>
<td></td>
<td>Worker Safety</td>
<td>Provide safety update and message(s).</td>
</tr>
<tr>
<td></td>
<td>Passporting</td>
<td>Establish arrangements for passporting off system resources.</td>
</tr>
<tr>
<td>Operations Section</td>
<td>Customer Outages/Events</td>
<td>Review existing system status and assess capacity of existing resources against current and anticipated needs</td>
</tr>
<tr>
<td></td>
<td>Operations Areas Impacts</td>
<td>Identify areas with highest risk</td>
</tr>
<tr>
<td></td>
<td>Resources</td>
<td>Assess resource needs; determine if mutual aid/incremental off system resources are needed; determine if working resources should be allowed to go home to get rest periods, etc... set up Resource and Work Management Rooms</td>
</tr>
<tr>
<td></td>
<td>Damage Assessment Status</td>
<td>Place damage assessment resources on alert; determine if off system damage assessors should be secured</td>
</tr>
<tr>
<td></td>
<td>Transmission System Status</td>
<td>Eliminate planned outages/maintenance; restore system to normal operating conditions where feasible</td>
</tr>
<tr>
<td></td>
<td>Vegetation Resources</td>
<td>Confirm that adequate vegetation resources are available and assigned to appropriate areas.</td>
</tr>
<tr>
<td>Logistics Section</td>
<td>Hotels</td>
<td>Reach out to hotel providers to determine availability, place on alert for possible needs</td>
</tr>
<tr>
<td></td>
<td>Meals</td>
<td>Reach out to meal providers to determine availability, place on alert for possible needs</td>
</tr>
<tr>
<td></td>
<td>Staging Areas</td>
<td>Reach out to predestinated staging sites and associated service providers to determine availability, place on alert</td>
</tr>
<tr>
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<td>Fuel</td>
<td>Reach out to fuel providers to determine availability, place on alert for possible needs; pre-fuel all vehicles</td>
</tr>
<tr>
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<td>Materials</td>
<td>Reach out to material providers, place on alert for possible needs, pre-order storm kits where/when deemed necessary</td>
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<td>Security</td>
<td>Place security resources on alert for possible needs</td>
</tr>
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<td>Fleet</td>
<td>Place equipment and vehicle providers on alert for possible incremental needs</td>
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<td>Emergency Management Outreach</td>
<td>Discuss Emergency Management Outreach status/plans/strategy</td>
</tr>
<tr>
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<td>Customer Communications</td>
<td>Assess call center resource needs; place personnel on alert</td>
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<td>Walk In Centers</td>
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<td>Asset Information</td>
<td>Ensure all critical information systems are available; determine if circuit prints or system maps should be preprinted</td>
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<td>Customer Experience Section</td>
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<td></td>
<td>Walk In Centers</td>
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<td>Work Planning Section</td>
<td>Resource Status</td>
<td>Provide resource counts - needed, assigned, available, secured off system (mutual aid/business partners), in transit, released</td>
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<td>Check In</td>
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<td>Asset Information</td>
<td>Ensure all critical information systems are available; determine if circuit prints or system maps should be preprinted</td>
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<td>Executives/Officers</td>
<td>Regulatory Communications</td>
<td>Discuss details of information to be shared, and establish point(s) of contact</td>
</tr>
</tbody>
</table>
EPRP Appendix 6 Operations Section Information
**PSRT / Damage Assessment Process**

**Assumptions:** PSRT Active, Everyone on Mobile

---

**Customer Service**

1. **Customer Calls LGE/KU**
   - Reps enters ticket into TOE

---

**NMS / TOE / MOBILE**

1. **TOE creates Event in NMS**
   - NMS sends Event to Mobile
   - NMS Status Changes to ENR
   - NMS Status Changes to ONS
   - NMS Event Details Updated from Mobile

---

**DCC / PSRT**

1. **DCC/ Ops Center Reviews Event to Determine if Assessment Needed**
   - Yes: **Wire Down Event**
   - No: **DCC Manages Event**

---

**NMS Status Changes to CMP & WW/DA Reassigned**

1. **DCC Manages Event**
   - No: **NASS Process**
   - Yes: **Event Completed**

---

**Wire Down Event**

1. **PSRT Assigns Event to WW/DA**
   - WW/DA does Final Completion (Completed button) on MDT

---

**NASS Status**

1. **Event Completed**
   - DMG Events are created in NMS

---

**Customer Update**

1. **Customer Update sent=NO OUTAGE**

---

**Event Notes Populated**

1. **Event Notes Populated**

---

**Attachment to Response to AG-1 Question No. 400(a)**

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Wolfe
PSRT / Damage Assessment Process
Assumptions: PSRT Active, Non-Mobile off system assessors, Dispatchers inputting damages during assessment

Attachment to Response to AG-1 Question No. 400(a)  
Wolfe  
Page 215 of 422
Attachment to Response to AG-1 Question No. 400(a) 
Page 216 of 422 
Wolfe
EPRP Appendix 7 Customer Experience Information
<table>
<thead>
<tr>
<th>KU Municipal</th>
<th>Type of Service</th>
<th>Name</th>
<th>Primary Contact #</th>
<th>Alternate Contact #</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barbourville Utility Commission</td>
<td>Transmission</td>
<td>Josh Callihan</td>
<td>cell</td>
<td></td>
</tr>
<tr>
<td>Bardstown Municipal Light &amp; Water</td>
<td>Distribution</td>
<td>Jeff Mills</td>
<td>cell</td>
<td>office</td>
</tr>
<tr>
<td>Bardwell City Utilities</td>
<td>Distribution</td>
<td>Robin Phelps</td>
<td>cell</td>
<td>home</td>
</tr>
<tr>
<td>City of Berea</td>
<td>Transmission</td>
<td>Adrian Isaac</td>
<td>cell</td>
<td>personal cell</td>
</tr>
<tr>
<td>Corbin City Utilities Commission</td>
<td>Transmission</td>
<td>Ron Herd</td>
<td>cell</td>
<td></td>
</tr>
<tr>
<td>Falmouth City Utilities</td>
<td>Distribution</td>
<td>Gary Lea</td>
<td>cell</td>
<td>office</td>
</tr>
<tr>
<td>Frankfort Electric &amp; Water Plant Board</td>
<td>Transmission</td>
<td>Scott Hudson</td>
<td>cell</td>
<td>cell #2</td>
</tr>
<tr>
<td>Madisonville Municipal Utilities</td>
<td>Distribution</td>
<td>Chris Melton</td>
<td>cell</td>
<td>office</td>
</tr>
<tr>
<td>Nicholasville City Utilities</td>
<td>Transmission</td>
<td>Robert Blackford</td>
<td></td>
<td></td>
</tr>
<tr>
<td>City of Paris Combined Utilities</td>
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## Non-Native Electric Distribution Operations Preferred Suppliers

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<td>64804</td>
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<td>417-206-4047</td>
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<td>Bob Ray</td>
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**Non-Native Electric Distribution Operations Preferred Suppliers**

*Attachment to Response to AG-1 Question No. 400(a)*

*Page 225 of 422*
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Storm Kit Information

**KU Storm Kit (first response)**
The KU Storm Kit consists of three pallets of storm related materials. The pallets consist of one large bundle of 6A CW wire, several boxes of clamps, connectors, fuses and miscellaneous line hardware. The kit contains enough material to support 5 to 10 non-native contractor crews for the first 24 hours. The Materials Specialist will distribute materials from each pallet to the non-native crews as required. **See Storm Kits (LGE & KU) Tab for listing of materials.** The Service Storm Kits will be placed at the following locations:

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<td>Norton</td>
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**LG&E Storm Kit (first response)**
The LG&E Storm Kit is a single pallet consisting of four small wire hand coils and small tub containing an assortment of clamps, connectors, fuses, and miscellaneous line hardware. The kit contains enough material to support one non-native utility/contractor crew for the first 24 hours of a restoration event. **See Storm Kits (LGE & KU) Tab for listing of materials.** The Service Storm Kits will be placed at the following locations:

<table>
<thead>
<tr>
<th>Location</th>
<th>Kits</th>
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</thead>
<tbody>
<tr>
<td>Auburndale</td>
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<tr>
<td>Brownstown (IN)</td>
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attachment to Response to AG-1 Question No. 400(a)
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<th>DATE</th>
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<th>REQUESTER</th>
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<tr>
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<td>88135</td>
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<td>7010141-ANCHOR</td>
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<td>10-LGE/KU- CROSSARM</td>
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<td>Arm, Cross, Douglas Fir, 10'</td>
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<td>89621R10</td>
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<td>AF6030</td>
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<tr>
<td>1159194</td>
<td>Rod, Anchor, Bust 5/8 x 8' Twineye</td>
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</table>
Restaurant Set-up Process

Restaurants supplied from **Supply Chain/Logistics Emergency Response Procedures Manual (SCLERPM)**

1) Supply Chain assigned person will obtain a copy of appropriate Purchasing Card(s) for this Storm event from **Paul Tirey**.

2) Locate tab in the SCLERPM for appropriate Operation Center that food service is needed.

3) From “Operations Center specific Information” sheet find list of primary restaurants. These should be contacted first and most should have provided this service in the past.

4) If additional restaurants needed due to unavailability of primary sources due to storm outage.
   a) Contact the area operations center Administrative lead for suggestions.
   b) Google to search and enter “restaurants, (city), Kentucky.” This should produce a list of restaurants in that area with phone numbers and addresses. (See **Restaurant Form Tab** for blank form)

5) The following procedure has been developed and should be used as a tool when setting up restaurants with Purchasing Card.
   a) Ask for Manager on duty. (Introduce yourself LGE or KU a part of LG&E and KU Services Company and record Managers name to be used in restaurant list spreadsheet).
   b) Ask if they are willing to assist LGE/KU during Storm Restoration efforts (next few days) by providing meals for our Employees and Contractors to be paid by Purchasing Card? If authorization form is requested, see **Hotel/Restaurant Purchasing Card Authorization Form** tab.
   c) If they reply yes, then inform them of the following:
      1) Once on the property, all persons eating should be Contractors of LGE or KU or LGE/KU employees. Contractors will typically be wearing identification bands and LGE/KU employees should be wearing company IDs.
      2) Normal menu food and drink (**non alcoholic**) items should be ordered/purchased. When finished eating please have customer print and sign their name on receipts and also note name of their company on receipts. Receipts will be needed for verification and should be kept by restaurant until end of the storm event.
3) Note: add a 15% gratuity to bill for waiter or waitress.

4) Request that the restaurant process the charges daily.

d) All receipts should be mailed to:

   ATTN: Supply Chain  
   Purchasing Card Administrator  
   LGE and KU Services Company  
   PO Box 32020  
   Louisville, Kentucky 40232

e) Give Manager Purchasing Card information - (LGE or KU) whatever card is appropriate from card info received in step one, also leave your name and a phone number (office and/or cell) to call if they encounter any problems.

6) The following standard spreadsheet will be used to capture when restaurants have been set-up for contract and company crews. This spreadsheet will be maintained on the Supply Chain shared drive and the Supply Chain website:

<table>
<thead>
<tr>
<th>Location</th>
<th>Name</th>
<th>Address</th>
<th>Contact Managers</th>
<th>Telephone</th>
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<tr>
<td>Central</td>
<td>Steak &amp; Shake</td>
<td>3232 Bardstown Road</td>
<td>Dave</td>
<td>502-456-2670</td>
<td>24 hours</td>
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<tr>
<td>Central</td>
<td>Golden Corral</td>
<td>4032 Taylorsville Road</td>
<td>Scott</td>
<td>502-485-0004</td>
<td>11am – 9:00 pm</td>
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<tr>
<td>Central</td>
<td>Denny's</td>
<td>434 Eastern Pkwy</td>
<td>John</td>
<td>502-636-2538</td>
<td>24 hours</td>
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<tr>
<td>East</td>
<td>Hometown Buffet</td>
<td>1700 Alliant Ave (Blankenbaker)</td>
<td>Kim</td>
<td>502-267-7044</td>
<td>11am - 8:30 pm</td>
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</tbody>
</table>

Note: When restaurants are established, this information will be entered into the Resources on Demand (RoD) resource tracking system which can provide updates to Supply Chain and Operation Managers overseeing the storm restoration for the Bird Dogs with the restoration crews.

7) At the end of the Storm Event – Contact all restaurants on the set-up list, ask for Manager, and inform them of the cut-off time for accepting any additional request for meals covered by the LGE and/or KU Storm Purchasing Cards. At this time also remind them they need to send in the receipts for all charges as noted above in 5(d).

**Emergency Individual “Storm” Purchasing Cards (Primarily Level I)**

Storm Purchasing Cards held by Team Leaders or Birddogs (cardholder) shall only be used in areas outside the heavy concentration restoration areas where Corporate Storm Process has not been activated. Individual Storm Purchasing Cards are intended to be used in sparsely / sporadic restoration areas. Collection of receipts and reconciling of statement will be the cardholder’s responsibility. “Emergency Response Level I Storms” will be handled using the Individual “Storm” Purchasing Cards on an as needed basis with management responsibility controlled by Team Leaders or Birddogs.”
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<td>Papa Johns Cardinal Stadium</td>
<td>2800 S. Floyd Street Louisville, KY 40209</td>
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<td>937 Phillips Lane Louisville, KY 40209</td>
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<td>Greenville</td>
<td>Muhlenberg County Agricultural and Convention Center</td>
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<td>Barlow</td>
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<td>137 S. Fourth Street Barlow, KY</td>
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### Staging Areas Information

#### Suppliers

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<tr>
<td>R&amp;K</td>
<td>11600 Blankenbaker Access</td>
<td>Richard Fahringer</td>
<td>Richard Fahringer</td>
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<td>Vehicle Staging</td>
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<tr>
<td></td>
<td>Louisville, KY 40299</td>
<td>Michael Fahringer</td>
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<tr>
<td>Emergency Disaster Services (EDS)</td>
<td>1385 Pridemore Court</td>
<td>Jerry Lundergan, Owner</td>
<td>Jerry Lundergan</td>
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<td>On-site food, lodging, sanitary facilities, laundry service, etc.</td>
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<tr>
<td></td>
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<tr>
<td>Catering Cajun of Georgia, Inc.</td>
<td>2409 Shallowford Road NE</td>
<td>Jerry Lundergan, Owner</td>
<td>Jerry Lundergan</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kelly and Company, 1st Responders, LLC</td>
<td>Rt. 2, Box 512</td>
<td>Steve Kelly</td>
<td>Steve Kelly</td>
<td></td>
<td>On-site food, lodging, sanitary facilities, laundry service, etc.</td>
</tr>
<tr>
<td></td>
<td>Norwood, MO 65717</td>
<td>Anthony Kelly</td>
<td>Anthony Kelly</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Timothy Kelly</td>
<td>Timothy Kelly</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Office</td>
<td>Office</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Storm Services, LLC</td>
<td>272 Oak Hill Road</td>
<td>Tommy Hopkins</td>
<td>Tommy Hopkins</td>
<td></td>
<td>Specializes in the design, construction, operation, &amp; management of full base camp setups</td>
</tr>
<tr>
<td></td>
<td>Cairo, GA 39828</td>
<td>Ann Hopkins</td>
<td>Ann Hopkins</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Toll Free</td>
<td>Toll Free</td>
<td></td>
<td></td>
</tr>
<tr>
<td>International Management Assistance Corp.</td>
<td>15830 Foltz Parkway</td>
<td>David Levine</td>
<td>David Levine</td>
<td></td>
<td>On-site food, lodging, sanitary facilities, laundry service, etc.</td>
</tr>
<tr>
<td></td>
<td>Cleveland, Ohio 44149-4745</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LG Fox, Inc.</td>
<td>1692 Jaggie Fox Way</td>
<td>Charlie Waugh</td>
<td>Charlie Waugh</td>
<td></td>
<td>Portable Generators</td>
</tr>
<tr>
<td></td>
<td>Lexington, KY 40578</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cummings Crosspoint, LLC</td>
<td>9820 Bluegrass Pkwy.</td>
<td>Brian Leis</td>
<td>Brian Leis</td>
<td></td>
<td>Portable Generators</td>
</tr>
<tr>
<td></td>
<td>Louisville, KY 40299</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Evans Construction Co</td>
<td>4807 Chenoweth Run Rd</td>
<td>Ann Evans</td>
<td>Ann Evans</td>
<td></td>
<td>Janitorial Services/Light Maintenance</td>
</tr>
<tr>
<td></td>
<td>Louisville, KY 40299</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rumpke</td>
<td>7501 Grade Lane</td>
<td>Ann Evans</td>
<td>Ann Evans</td>
<td></td>
<td>Port-A-Can/Hand Washing Stations</td>
</tr>
<tr>
<td></td>
<td>Louisville, KY 40219</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waste Mgmt</td>
<td>2673 Outer Loop</td>
<td></td>
<td></td>
<td></td>
<td>Port-A-Can/Hand Washing Stations</td>
</tr>
<tr>
<td></td>
<td>Louisville, KY 40219</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
EPRP Appendix 9 Work Planning Section
**Work Planning**

When Work Planning is activated, the **Resource Tracking** team will setup at the BOC in Training Room H located on the lower level. This team is responsible for tracking mutual assistance and other off-system crews while in-transit who have committed to assisting us. They make contact with the General Foreman to confirm crew counts, lodging requirements and estimated times of arrival, and they instruct the General Foreman on where to check-in once they arrive. They also enter crew level information into Resources on Demand (RoD) including estimated arrival times and lodging requirements. The Resource Tracking team then enters detailed team member information once rosters are received.

The central phone number for Work Planning in Training Room H is **627-2046**. If it does not get answered or it is busy, the call will roll to the phones that are signed on (x3881, 3882, 3884, 3885, 3886, 3887, 3888 & 3889). To “sign on,” come off hook and hit #2 then hang up. That phone is then ready to accept calls. To “sign off,” come off hook and hit *2.

If Resource Tracking shuts down for the night, the central number must be forwarded to someone’s cell phone until the day shift begins.

The central email address for the Resource Tracking team is **Storm.Resources@lge-ku.com**

This number and email address should be given to General Foremen as contact information while traveling. They must be manned and monitored at all times.

The **Resource Check-in** team is also activated as part of Work Planning. This team will co-locate with Safety at the location designated for safety training or “passporting” off-system crews as they arrive. The Resource Check-in team will validate each individual working on our system, will enter them into RoD if necessary and indicate their actual time of arrival.

If the check-in point does not have connectivity to the LG&E/KU network, a few personal WiFi devices are available and should be used by the Resource Check-in team(s). When you turn the device on, it will give you the network name and password. You will then need to connect your PC to this network. You will need power for prolonged use.

This job aid is a guide on how to track mutual assistance and other off-system resources, using Resources on Demand, that assist LG&E and/or KU during a significant power outage.

**Access RoD**

From the intranet home page, select **Applications>P-T>Resources on Demand**. You will automatically be logged into Resources on Demand.

**Log Out**

To log out of Resources on Demand (RoD), click on the **X** on the Internet Explorer window.
**Resources View**

**Note:** When entering information, all fields with an asterisk (*) are mandatory and must be filled in.

**Manually Add New Team**

1. From the main menu, select **Resources, Resources View**.

2. Click the icon to add a row at the end of the table.

3. Enter the following team information. All of the values, except where otherwise noted, are entered by the Resource Tracking team. Refer to the **Quick Reference Guide** for definition of fields.

<table>
<thead>
<tr>
<th>Team Fields</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Team ID, Team Name, Team Type, Team Function, Team Role, Company Name, Status (to activate the team), Use Roster, System Type, Operating Center, Crew Center, Local Area</strong></td>
</tr>
</tbody>
</table>

- **Team Fields:** *Team ID, Team Name, *Team Type, *Team Function, *Team Role, *Company Name, *Status (to activate the team), Use Roster, *System Type, *Operating Center, Crew Center, *Local Area

**Note:** Team ID is ten (10) characters long and must be unique. The naming convention is: 3 letter company code; 3 letter team type; 3 digit number (AEPMAU100, DHEMAC200, PKEOSC100, etc.).

Company codes: PKE=Pike, DHE=Davis H Elliot, FIS=Fishel, GRV=Groves, HAL=Hall, HEN=Hendrix, UNI=United … others to be determined “on the fly;”

Team types: MAU=Mutual Assistance Utility, MAC=Mutual Assistance Contractor, OSC=Off System Contractor;

Numbers: Incremental numbering of your choosing to ensure unique team IDs.

**Note:** Team Name is free-form text and is usually made up of the Company name and Foreman last name.

**Note:** Use Roster – check this box once you have a roster and are ready to enter team member information, otherwise leave it unchecked and enter straw counts.

**Team Leadership**

- **Team Leadership:** Team Lead, TL Cell Phone, General Foreman, General Foreman Phone
Straw Counts

<table>
<thead>
<tr>
<th>Team ID</th>
<th>Team Name</th>
<th>Bird Dog</th>
<th>Bull Dog</th>
<th>Customer Center Reps</th>
<th>Damage Assessors</th>
<th>Dispatcher</th>
<th>General Foreman</th>
<th>Line Worker</th>
<th>Management</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>18</td>
<td>DHE Management</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>151</td>
<td>9</td>
</tr>
<tr>
<td>18</td>
<td>Abbott, Mike</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>79</td>
<td>1</td>
</tr>
<tr>
<td>18</td>
<td>Davis, Tim</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>4</td>
<td>0</td>
</tr>
</tbody>
</table>

Straw counts – enter number for Bird Dog, Bull Dog, Customer Center Reps, Damage Assessors, Dispatcher, General Foreman, Line Worker, Management, Other, PSRT Dispatch Lead, PSRT Field, PSRT Office, Safety, Security, Substation, Transmission, Vegetation, Total Members (auto calculated)

Note: Once the Use Roster checkbox is checked, all straw counts entered will be overridden by the information entered in to the Team Members screen, the counts will become automatically calculated.

Team Equipment

<table>
<thead>
<tr>
<th>Team ID</th>
<th>Team Name</th>
<th>Backhoe</th>
<th>Bucket Truck</th>
<th>Chipper</th>
<th>Digger Derrick</th>
<th>Dozer</th>
<th>Dump Truck</th>
<th>Mini Derrick</th>
<th>Other Equipment</th>
<th>Pickup</th>
<th>Service Truck</th>
<th>Total # Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>18</td>
<td>DHE Management</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>46</td>
</tr>
<tr>
<td>18</td>
<td>Abbott, Mike</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>18</td>
<td>Davis, Tim</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>18</td>
<td>Bushnell, Joe</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

- **Team Equipment**: If available, enter straw counts for Backhoe, Bucket Truck, Chipper, Digger Derrick, Dozer, Dump Truck, Mini Derrick, Other Equipment, Pickup, Service Truck, Total # Equipment (auto calculated)

Note: Once the Use Roster checkbox is checked, all straw counts entered will be overridden by the information entered in to the Team Members screen, the counts will become automatically calculated.

Other Information

<table>
<thead>
<tr>
<th>Team ID</th>
<th>Team Name</th>
<th>Work Planning Contact</th>
<th>Work Planning Phone</th>
<th>Departure Date Time</th>
<th>Estimated Time of Arrival</th>
<th>Actual Time of Arrival</th>
<th>Passport Site</th>
<th>Passport ETA</th>
<th>Passport ATA</th>
<th>Passport Status</th>
<th>Passport Date/Time</th>
<th>Roster Verified</th>
<th>Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>18</td>
<td>DHE Management</td>
<td>Paul Wesl</td>
<td>11/17/2012 12:46</td>
<td>11/17/2012 14:00</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Abbott, Mike</td>
<td>Paul Wesl</td>
<td>11/17/2012 12:46</td>
<td>11/17/2012 14:00</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Davis, Tim</td>
<td>Paul Wesl</td>
<td>11/17/2012 12:46</td>
<td>11/17/2012 14:00</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Bushnell, Joe</td>
<td>Paul Wesl</td>
<td>11/17/2012 12:46</td>
<td>11/17/2012 14:00</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Team Departure/Arrival and Other Information**: Work Planning Contact, Work Planning Phone, Departure Date Time, Estimated Time of Arrival (Note: This field needed for Logistics.)

The following fields are entered by the Resource Check-in team once the crews have been passported: Actual Time of Arrival, Passport Site, Passport Status, Roster Verified

- **Team Origin**: Home State, Home Utility, Home Office Contact, Home Office Phone #, Home Office e-mail
• **Team’s Lodging and Logistic Requirements**: Requires Lodging, # of Singles, # of Doubles, # of Others, # of Females

4. Click **Save**.

5. Email Notification – when adding teams or changing locations of existing teams, an email pop-up box displays. This is meant to notify the Logistics team when teams move and need lodging at their new location. Add Comments if necessary to describe any particular situation and send the notice to Paul Tirey. First Name = Paul, Last Name = Tirey, Email Address = [Redacted]

### Team Member Info (Roster)

**Add New Team Members**

1. From the main menu, select **Resources, Resources View**.

2. Select a team by clicking on the **Team ID Hyperlink**. The Team Member Information screen opens.

3. Click the **icon** to add a row at the end of the table.

4. Enter the following team information: *Last Name, *First Name, *Gender, Cell Phone, E-mail, Radio, Personnel ID, *Personnel Type, *Storm Role, Passport ID (entered by **Resource Check-in**), Crew ID, Team Lead, Crew Leader, Home State, Bed Type, Requires Lodging, Union, Comments, Original Team ID (*automatically populated), Equipment ID, Equipment Type, Equipment Description, Equipment Radio and Equipment Cell

<table>
<thead>
<tr>
<th><strong>Last Name</strong></th>
<th><strong>First Name</strong></th>
<th><strong>Gender</strong></th>
<th><strong>Cell Phone</strong></th>
<th><strong>Radio</strong></th>
<th><strong>E-mail</strong></th>
<th><strong>Personnel ID</strong></th>
<th><strong>Personnel Type</strong></th>
<th><strong>Storm Role</strong></th>
<th><strong>Passport ID</strong></th>
<th><strong>Crew ID</strong></th>
<th><strong>Team Lead</strong></th>
<th><strong>Crew Leader</strong></th>
<th><strong>Home State</strong></th>
<th><strong>Bed Type</strong></th>
<th><strong>Requires Lodging</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cowart</td>
<td>Tim</td>
<td>Male</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>McCubbin</td>
<td>Robert</td>
<td>Male</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clark</td>
<td>Dale</td>
<td>Male</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Note**: Much of the time, the information illustrated above is the most information provided for team members.

**Note**: Reference the **Quick Reference Guide** for definitions of Personnel Type and Storm Role.

5. Click **Save**.
Resource Tracking – screens and fields

The Resource Tracking team tracks Mutual Assistance and other off-system crews while they are in-transit to the check-in/passporting site. They will use the Resources View screen to capture company/crew level information in the following fields.

<table>
<thead>
<tr>
<th>Field</th>
<th>Example Entry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team ID</td>
<td>PKEMAU100 (company, team type, number)</td>
</tr>
<tr>
<td>Team Name</td>
<td>Pike – Joe Smith (company, foreman name)</td>
</tr>
<tr>
<td>Team Type</td>
<td>Off System Contractor, Mutual Assistance Contractor, or Mutual Assistance Utility</td>
</tr>
<tr>
<td>Team Role</td>
<td>Line Workers</td>
</tr>
<tr>
<td>Company Name</td>
<td>Pike</td>
</tr>
<tr>
<td>Status</td>
<td>Active</td>
</tr>
<tr>
<td>Use Roster</td>
<td>Check if entering individual team members, Uncheck if entering straw counts for resources</td>
</tr>
<tr>
<td>System Type</td>
<td>Off</td>
</tr>
<tr>
<td>Operation Center</td>
<td>LGE (the work location they in which they will be helping)</td>
</tr>
<tr>
<td>Crew Center</td>
<td>LGE</td>
</tr>
<tr>
<td>Local Area</td>
<td>LGE</td>
</tr>
<tr>
<td>Team Lead</td>
<td>Joe Smith (crew foreman)</td>
</tr>
<tr>
<td>TL Cell Phone</td>
<td>(502)555-1212</td>
</tr>
<tr>
<td>General Foreman</td>
<td>David Cassidy (general foreman for the company)</td>
</tr>
<tr>
<td>GF Phone</td>
<td>(502)555-1213</td>
</tr>
<tr>
<td>BirdDog-Vegetation</td>
<td>straw counts, people – enter number for Line Worker if not using rosters (enter other counts when applicable)</td>
</tr>
<tr>
<td>Backhoe-Service Truck</td>
<td>straw counts, equipment – enter counts for each equipment type known if not using rosters</td>
</tr>
<tr>
<td>Work Planning Contact</td>
<td>MistyWhite (your name here! 😊)</td>
</tr>
<tr>
<td>Work Planning Phone</td>
<td>(502) 627-2046 (central number or your cell number)</td>
</tr>
<tr>
<td>Departure Date/Time</td>
<td>2/14/2014 14:00</td>
</tr>
<tr>
<td>Estimated Time Arrival</td>
<td>2/14/2014 21:00</td>
</tr>
<tr>
<td>Home State</td>
<td>Virginia</td>
</tr>
<tr>
<td>Home Utility</td>
<td>AEP (in this case, Pike normally works for AEP in VA)</td>
</tr>
<tr>
<td>Home Office Contact</td>
<td>enter if known</td>
</tr>
<tr>
<td>Home Office Phone</td>
<td>enter if known</td>
</tr>
<tr>
<td>Home Office Email</td>
<td>enter if known</td>
</tr>
<tr>
<td>Hours Tracking</td>
<td>enter start time equal to Departure Date/Time</td>
</tr>
<tr>
<td>Requires Lodging</td>
<td>Check if they will require lodging &lt;- usually yes</td>
</tr>
</tbody>
</table>

If the Resource Tracking team has rosters, check the “Use Roster” checkbox and enter information in the Team Member screen.
Resource Check-In – screens and fields

The Resource Check-In team is co-located with the Safety Team at the passporting/check-in site. Once off-system resources have been “passported” (safety trained), they check-in by providing a form with pertinent information on it.

The following additional information is then added in the Resources View screen.

<table>
<thead>
<tr>
<th>Field</th>
<th>Example Entry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual Time of Arrival</td>
<td>2/14/2014 22:30</td>
</tr>
</tbody>
</table>

If the Resource Tracking team did not enter rosters, the Resource Check-In team must now check the “Use Roster” checkbox and enter information in the Team Member screen, including the Passport ID. If rosters are already loaded, then simply add the Passport ID.

<table>
<thead>
<tr>
<th>Field</th>
<th>Example Entry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Last Name</td>
<td>Smith</td>
</tr>
<tr>
<td>First name</td>
<td>Joe</td>
</tr>
<tr>
<td>Gender</td>
<td>Male</td>
</tr>
<tr>
<td>Cell Phone</td>
<td>(502)555-1212</td>
</tr>
<tr>
<td>Personnel Type</td>
<td>Line Workers <em>(pick the appropriate personnel type)</em></td>
</tr>
<tr>
<td>Storm Role</td>
<td>Journeyman <em>(pick the appropriate storm role)</em></td>
</tr>
<tr>
<td>Team Lead</td>
<td>Check if he/she is the team lead/foreman</td>
</tr>
<tr>
<td>Home State</td>
<td>Virginia</td>
</tr>
<tr>
<td>Requires Lodging</td>
<td>Check if they will require lodging &lt;- usually yes</td>
</tr>
<tr>
<td>Equipment ID</td>
<td>100 <em>(enter unique equipment ID)</em></td>
</tr>
<tr>
<td>Equipment Type</td>
<td>Bucket Truck <em>(pick the appropriate equipment type)</em></td>
</tr>
</tbody>
</table>

Resource Check-In – screens and fields

The Resource Check-In team is co-located with the Safety Team at the passporting/check-in site. Once off-system resources have been “passported” (safety trained), they check-in by providing a form with pertinent information on it.

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</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Field</th>
<th>Example Entry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Last Name</td>
<td>Smith</td>
</tr>
<tr>
<td>First name</td>
<td>Joe</td>
</tr>
<tr>
<td>Gender</td>
<td>Male</td>
</tr>
<tr>
<td>Cell Phone</td>
<td>(502)555-1212</td>
</tr>
<tr>
<td>Personnel Type</td>
<td>Line Workers <em>(pick the appropriate personnel type)</em></td>
</tr>
<tr>
<td>Storm Role</td>
<td>Journeyman <em>(pick the appropriate storm role)</em></td>
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<tr>
<td>Team Lead</td>
<td>Check if he/she is the team lead/foreman</td>
</tr>
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<td>Home State</td>
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<tr>
<td>Requires Lodging</td>
<td>Check if they will require lodging &lt;- usually yes</td>
</tr>
<tr>
<td>Equipment ID</td>
<td>100 <em>(enter unique equipment ID)</em></td>
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<tr>
<td>Equipment Type</td>
<td>Bucket Truck <em>(pick the appropriate equipment type)</em></td>
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</tbody>
</table>
Other Helpful Tips

Managing Team Splits And Team Member Moves

Split an Existing Team by Creating a New Team

1. From the main menu, select Resources, Resource View.

2. Select the team to be split by clicking in the cell to the left of the Team ID.

3. Click Manage Teams.

4. In the left hand pane, view the team to be split. In the right hand pane, enter the following to create a new team: *Team ID, *Company Name, Team Name, *Team Type, Shift, *Team Function, *Team Role, *Operation Center, Team Home, *Local Area, *System Type.

5. Click Save.

6. Review team members to move from the left hand pane and assign to the right hand pane (new team).

7. Select team member by clicking in the cell to the left of the team member name.

8. Click the arrows to add/remove team members from one team to the other.

9. Click Save.

Move a Resource from an Existing Team to Another

1. From the main menu, select Resources, Resources View.

2. Select the team to move resources from by clicking in the cell to the left of the Team ID.

3. Click Manage Teams.

**Note:** The left pane is the source team that was selected. The right pane is the target team.

4. In the Team ID field on the right pane, type in the Team ID of the team to add the resource to and then tab out of Team ID field.

5. Select team member(s) from source team by highlighting the row of the team member(s).

**Note:** Team members are displayed at the bottom of source screen.

6. Click the arrow to move team member(s) to target team.

7. Click Save and Return to Resource View.
Resources View Bulk Operations

The following options are available in the Resources View main display grid after clicking the row header to select a team:

Note: Multiple teams can be selected by using the Ctrl button.

Change a Team’s Local Area
1. Select Change Local Area.
2. Select Operation Center: and Local Areas: from the drop-down to change team’s reporting staging center.
3. Enter ETA Date & Time: or select calendar icon.
4. Click Update Local Areas to save changes to team location.
5. Click OK.

Update Team Status
1. Select Update Teams Status.
2. Make a selection from the drop-down.
3. Click Update Team Status.
4. Click OK.

Update Team’s ETA
1. Select Update ETA.

Note: Multiple teams can be selected to update their ETA by dragging cursor.
2. Enter *ETA Date & Time: or select calendar icon.
3. Click Update ETA.
4. Click OK.

Change Team ID
1. Select Change Team ID.
2. Select Selected Team ID: and enter New Team ID:. (Note: New Team ID must not exist already.)
3. Click Update.
4. Click OK.
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<td>David White, CLCP, Safety Instructor</td>
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<td>Owensboro Municipal Utilities</td>
<td>Tim Lyons, Director Engineering</td>
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<td>200 First Street SE</td>
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<tr>
<td>Cedar Rapids, IA 52401-1409</td>
<td>Lacey Hogan</td>
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<tr>
<td>800.255.4268</td>
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<td>NOTES: 24/7 Distribution Dispatch Center - IPL 800.526.3323</td>
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<td>800.255.4268</td>
<td>Mike Schmid</td>
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<tr>
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<tr>
<td>866.899.3204</td>
<td>Thomas Betthauser</td>
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<tr>
<td>Emergency Control Center 877.402.5228</td>
<td>NOTES: Nick Grossenbach Ph: 262.506.6770</td>
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<tr>
<td><strong>ITC MIDWEST</strong></td>
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<tr>
<td>27175 Energy Way</td>
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<td>Novi, MI 48377</td>
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<td>133 South Blair</td>
<td>Jim Lorenz</td>
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<tr>
<td>Madison, WI 53703</td>
<td>Richard (Dick) Schwarz</td>
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<tr>
<td>608.252.7111</td>
<td>Mitch Grundahl</td>
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<td>Fax: 608.252.1591</td>
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<tr>
<td><strong>MINNESOTA POWER- ALLETE</strong></td>
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<tr>
<td>3215 Arrowhead Rd.</td>
<td>John Muehlbauer, Supt Line</td>
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<td>Duluth, MN 55811</td>
<td>Tim Laeupplie, Supt Line</td>
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<tr>
<td>218.722.2641</td>
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<td>Fax # 218.720.2775</td>
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<td><strong>NORTHWESTERN ENERGY</strong></td>
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<tr>
<td>600 Market</td>
<td>Jason Merkel</td>
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<tr>
<td>Huron, SD 57350</td>
<td>Steve Arbach</td>
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<td>605.352.8411</td>
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<td><strong>OTTER TAIL POWER COMPANY</strong></td>
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## MIDWEST MUTUAL ASSISTANCE

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<tr>
<td>6 Executive Drive</td>
<td>Riley Adams</td>
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<td>Marvin Morey</td>
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<td>Dave Muntean</td>
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<td>St. Louis, MO 63166-6149</td>
<td>Vince Grelle</td>
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<td>800.552.7583</td>
<td>Mike Reeneri</td>
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<td>David Bunge</td>
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<td><strong>NOTES:</strong> The Xcel Energy Operating Companies are Northern States Power Co.</td>
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<td>Fax # 920.433.1758</td>
<td>Craig Kahoun</td>
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<tr>
<td>XCEL ENERGY- PUBLIC SERVICE COMPANY OF COLORADO</td>
<td>1800 Larimer Street</td>
<td>Jay W. Smith</td>
<td>303.571.3927</td>
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<td>Denver, CO 80202</td>
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<td>LG &amp; E AND KU ENERGY LLC</td>
<td>820 West Broadway</td>
<td>Morgan Pfeiffer</td>
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<td></td>
<td>Louisville, KY 40202</td>
<td>Jamie Archer</td>
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<td>Steve Woodworth</td>
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<td>INDIANAPOLIS POWER AND LIGHT COMPANY</td>
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<td>Dan Davenport</td>
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<td>Dave Rohlman</td>
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<td>KCP&amp;L</td>
<td>P.O. Box 418679</td>
<td>Carol Baxter</td>
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<td>Kansas City, MO 64141-9679</td>
<td>Randy Watson</td>
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<td>816.556.2200</td>
<td>Chris Kurtz</td>
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<td>NOTES: Acquired Aquila Networks, St. Joe Light &amp; Power, Aquila</td>
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<td>MIDWEST ENERGY</td>
<td>1330 Canterbury Road</td>
<td>Dale Giebler</td>
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<td></td>
<td>Hays, KS 67601</td>
<td>Fred Taylor</td>
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<td>800.222.3121</td>
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<td>Fax # 785.625.1487</td>
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<td>WESTER ENERGY</td>
<td>P.O. Box 889</td>
<td>Bryan Nowlin</td>
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<td>Topolka, KS 66601</td>
<td>Natalie Rolfe</td>
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<td>785.575.6300</td>
<td>Sandy Zordel</td>
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<td>Phil Lewis</td>
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<tr>
<td>Columbus, OH 43215</td>
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<tr>
<td>Joplin, MO 64802-0127</td>
<td>Sam McGarrah</td>
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<td>417.625.5100</td>
<td>Jeff Westfall</td>
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<td>Fax # 417.625.5165</td>
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<td><strong>ENTERGY</strong></td>
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<td>P.O. Box 1640</td>
<td>Mike Fricke</td>
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<tr>
<td>Jackson, MS 39215</td>
<td>David Luthe</td>
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<tr>
<td>601.985.2750</td>
<td>Billy Blaylock</td>
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<td>Fax # 601.985.2366</td>
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<td>Emergency Control Center # 504.374.4461</td>
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<td><strong>OG &amp; E ELECTRIC SERVICE</strong></td>
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<td>P.O. Box 321</td>
<td>Rick Berg</td>
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<td>Oklahoma City, OK 73101-0521</td>
<td>Gary Rowlett</td>
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<td>405.553.3000</td>
<td>Robert Gottshall</td>
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<td>Thomas Kiesel</td>
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<td>Lewisville, TX 75077</td>
<td>Pauline Moore</td>
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<td>972.317.5542, X407</td>
<td>Evans Spanos</td>
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<td><strong>ONCOR ELECTRIC DELIVERY</strong></td>
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<td>1616 Woodall Rodgers Fwy, Ste. 7B-006</td>
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Great Lakes Mutual Assistance Group
Governing Principles

Introduction

The Great Lakes Mutual Assistance group (GLMA) is a consortium of large investor owned electric utility companies pulled together to effectively and collaboratively share electric restoration resources as needed to respond to significant outage events within the Midwest/Great Lakes region of the United States. The group first convened March 2005 with thirteen members. Since its initial meeting, the GLMA has met at least annually to discuss and establish guiding principles, share best practices, and assess and respond to related industry issues.

Mission

GLMA’s primary mission is to facilitate safe, effective, and coordinated regional emergency assistance efforts among member companies and other regional mutual assistance groups (RMAGs).

Membership

1. Membership (Member Company) in GLMA shall be defined at:
   a. An Operating Company level, where only one Operating Company under a Holding Company maintains membership in GLMA; or
   b. A Holding Company level.
2. Participation in GLMA shall be limited to sixteen (16) Member Companies as defined in 1 above.
3. To be considered for membership in GLMA, the Operating or Holding Company:
   a. Must be investor owned;
   b. Must have an electric service area that is within the footprint of GLMA’s established membership territory;
   c. Must sign or have signed the Edison Electric Institute (EEI) Governing Principles Covering Emergency Assistance Arrangements Between EEI Member Companies;
   d. Must present Company information and membership justification to member utilities at a scheduled GLMA meeting; and
   e. Must be elected unanimously by existing members.
4. The GLMA is currently comprised of the following members:
   a. AES Corporation
      i. Dayton Power & Light (DP&L)
      ii. Indianapolis Power and Light (IP&L)
   b. American Electric Power (AEP)
      i. AEP Ohio
      ii. Appalachian Power
      iii. Indiana Michigan Power
      iv. Kentucky Power
   c. Consumers Energy
   d. DTE Energy
e. Duke Energy Corporation
   i. Duke Energy Indiana
   ii. Duke Energy Kentucky
   iii. Duke Energy Ohio
f. Duquesne Light Company (DLC)
g. Exelon Corporation
   i. Commonwealth Edison (ComEd)
h. First Energy Corp (FE)
   i. Cleveland Electric Illuminating Company
   ii. Monogahela Power
   iii. Ohio Edison
   iv. Penelec
   v. Pennsylvania Power Company
   vi. Potomac Edison
   vii. Toledo Edison
   viii. West Penn Power
i. ITC Holdings (ITC)
j. Pennsylvania Power and Light (PPL) Corporation
   i. LG&E and KU Energy LLC (LKE)
k. Northern Indiana Public Service Company (NIPSCO)
l. Vectren Corporation
   i. Vectren Energy Delivery of Indiana - South
m. We Energies

Membership Territory

The GLMA membership territory is defined to include the geographical service areas of approved operating companies with service territory located within a 300 mile radius of Lima, Ohio. Proposed changes to this footprint must be submitted to the GLMA governing body, and be voted on by members in accordance with rule 5 under the Organization and Governance section of these governing principles.
Organization and Governance

1. The GLMA group shall be governed under the following structure (Governing Body):
   a. **Chair (1) –**
      i. Responsible for providing guidance and direction on GLMA governing principles, serving as a mentor and subject matter expert for the group, scheduling and developing agenda topics for periodic GLMA meetings, designating special working groups and committees, and keeping members abreast of industry related issues and governance status.
      ii. Responsible for serving as the primary GLMA representative on the EEI Mutual Assistance / Emergency Preparedness Executive Committee, National Mutual Assistance Resource Team, and with other regional mutual assistance or industry mutual assistance working groups.
   b. **Vice-Chair (1) –**
      i. Responsible for assisting the Chair, leading special working groups or committees, developing agenda items for periodic meetings, working with host utilities on meeting logistics, and serving as a mentor and subject matter expert for the group.
      ii. Responsible for serving as the secondary GLMA representative on the EEI Mutual Assistance Executive Committee, National Mutual Assistance Resource Team, and with other regional mutual assistance or industry mutual assistance working groups.
   c. **Secretary (1) –** Responsible for documenting and distributing meeting minutes utilizing a standard format, assisting with periodic meeting preparations and agenda development, and assisting other GLMA governance positions as needed.
   d. **Secretary-in-Waiting (1) –** Responsible for assisting all Governing Roles, and serving as a backup to the Secretary position.

2. The four Governing Roles shall serve a one (1) year term.
3. No member company shall hold more than one Governing Role concurrently.
4. All Governing Roles shall be filled according to the following:
   a. The Secretary-in-Waiting position shall be filled, during the annual Spring Meeting or when vacated prematurely, through a nomination and silent election process.
   b. The Secretary position shall be filled by the individual holding the Secretary-in-Waiting position, by rotating them into the role at the annual Spring Meeting or when the Secretary is vacated prematurely.
   c. The Vice-Chair position shall be filled by the individual holding the Secretary position, by rotating them into the role at the annual Spring Meeting or when the Vice-Chair is vacated prematurely.
   d. The Chair position shall be filled by the individual holding the Vice-Chair position, by rotating them into the role at the annual Spring Meeting or when the Chair position is vacated prematurely.
   e. Nominations for Governing Roles shall only be considered if submitted by a Member Company to all other Member Companies verbally during a planned meeting or via email.
No individual should be nominated for a Governing Role unless he or she has agreed to assume the role if elected for the position.

f. Silent elections for Governing Roles shall be conducted in one of two ways:
   i. If a vacant Governing Role is to be filled during a planned GLMA meeting, candidates
      will be presented to member companies by the Chair or their designee. Member
      companies shall exercise their vote for their preferred candidate by “show of hand”
      when the candidate’s name is presented, with all candidates for the Governing Role
      not in attendance.
   ii. If a vacant Governing Role is to be filled outside of a planned GLMA meeting,
       candidates shall be presented to member companies via email by the Chair or their
       designee. Member companies shall exercise their vote via email to the GLMA
       Secretary or their designee, as agreed upon by the member companies.
   iii. Member Companies will be afforded one vote per Governing Role.
   iv. Vacant Governing Roles will be offered to the nominated candidate who receives
       the majority of votes.

5. Policies and procedures associated specifically with the GLMA shall be voted on by Member
   Companies. Each Member Company shall be afforded one vote per decision item.
   a. Unanimous votes shall be required for the following items:
      i. New members
      ii. Membership Boundaries
      iii. Governing Principles
   b. Majority votes shall be required for the following items:
      i. Governing Roles
      ii. Meeting Locations
      iii. Procedural Changes

6. Member Holding Companies with multiple Operating Companies may designate a separate
   representative(s)/participant for each Operating Company during GLMA meetings and joint
   mobilization conference calls. However, Member Holding Companies are limited to a single vote for
   any voting activities.

7. All GLMA members shall periodically and, as necessary, identify their Home RMAG by Operating
   Company to enable GLMA to conform with and effectively execute EEI’s National Response Event
   (NRE) procedures for national level resource mobilization events.

Meetings

1. GLMA members shall meet at least annually, in the spring, to review GLMA activities, discuss open
   items and new business, and assess industry issues and their impacts on the GLMA. During the
   annual meeting or as needed, Member Companies can elect to conduct more frequent meetings.
2. Meetings shall be rotated between Member Companies.
3. The member company hosting a meeting shall be responsible for:
   a. Scheduling the dates and times for the meeting;
b. Coordinating lodging arrangements (i.e. reserving a block of rooms for a set period) for overnight members;
c. Providing meals, as necessary; and
d. Providing meeting rooms and associated resources (projectors, laptop, etc…).

4. Non-member companies (including vendors) will be allowed to participate in a GLMA meeting if invited by a Member Company and agreed to by all other Member Companies.

5. Non-member companies (including vendors) shall not be allowed to participate in GLMA business decisions, including any voting activities.

6. GLMA activities and statistical information shall be updated and distributed quarterly by the GLMA Secretary or their designee, and shall be presented at each GLMA meeting by the GLMA Chair. This information shall include:
   a. Number of calls;
   b. Number of internal requests;
   c. Number of resources moved internally; and
   d. Number of resources moved externally.

Mutual Aid Calls

1. Call Representation
   a. All Member Companies are expected to provide a primary and backup representative with contact information for mutual aid conference calls.
   b. Operating companies may be represented individually on joint mobilization calls.
   c. All Member Companies are expected to provide a representative on all requested calls. The Governing Body shall have authority to address any Member Company that doesn’t consistently participate on joint mobilization calls.
   d. Member Company representatives shall have their company’s authority to request, accept or release resources during a mutual assistance call.

2. Call Organization and Format
   a. All calls will follow a standardized call/spreadsheet agenda.
   b. Member Companies will share facilitation of mutual aid calls, with every effort being made to avoid having an impacted company host the call.
   c. Non-member companies or organizations shall not be permitted on GLMA calls without authorization or invitation from a GLMA member company. If a non-member is invited to participate in a call, the responsible member company shall announce the company or organization invited during the roll call process.
   d. At the beginning of each call, the call host shall request all non-members to identify themselves prior to proceeding with the call agenda.
   e. All Member Companies shall endeavor to mute their lines when not talking.
   f. Members understand that conversations between member utilities during Joint Mobilization Conference Calls are confidential and proprietary. Therefore, with the exception of general deployment data/information, members agree not to share or release
any information shared between member utilities during Joint Mobilization Conference Calls unless mutually agreed.

Resource Requests

1. Utilities needing assistance/resources shall initiate the mutual aid process by notifying the designated GLMA administrative representative or their backup and requesting that a mutual aid conference call be scheduled.

2. The designated administrative representative shall send out an electronic meeting notice/email with the following:
   a. Call number
   b. Call date and time
   c. Requesting utility
   d. Situation report
   e. Preliminary resource needs

3. During the mutual aid call, the requesting Company shall be responsible for communicating the following for responding utilities:
   a. Working conditions
   b. Contact information
   c. Reporting location
   d. Labor restrictions
   e. Crew size and composition
   f. Specialty equipment needs

4. In the event a requesting utility’s resource needs cannot be satisfied by GLMA members, the utility may seek assistance from an adjacent RMAG in which they are also a member. If the requesting GLMA member is not a member of an adjacent RMAG, they may request the GLMA Chair to submit a request for their needed resource to an adjacent RMAG, from GLMA.

Provision of Assistance

1. The GLMA Secretary shall be responsible for developing, maintaining, and routinely communicating a list of first wave resource levels for member companies.

2. When releasing contractors for assistance, every effort should be made to release them to companies where existing contracts are in place.

3. Member Companies providing assistance/releasing resources should provide released personnel and contractors all necessary contact information from the requesting Company.

4. Member Companies providing assistance or releasing resources should provide or coordinate provision of resource rosters to the requesting Company.

5. Prior to securing GLMA resources without execution of a GLMA joint mobilization call, the requesting Member Company should send out an email to all other Member Companies to ensure a GLMA joint mobilization call is not needed. A joint mobilization call should be scheduled should any Member Company express a potential need or issue.
6. Prior to releasing resources outside of the GLMA, an email should be sent out to Member Companies to ensure there are no needs or issues with releasing resources outside of the GLMA. A joint mobilization call should be scheduled should any Member Company express a potential need or issue.

**National Response Efforts**

Member Companies shall adhere to the Edison Electric Institute’s *National Response Event Structure and Principles Covering Emergency Assistance Arrangements between Edison Electric Institute Members Companies* when resource needs dictate that a national response effort be declared.

**Best Practices Surveys**

Member Company surveys shall only be shared with participating Member Companies.

**Approved: 3/26/2014**

**Revisions:**

- 9/30/2014 - added new territory map and associated language.
SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company’s needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company’s location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company’s employees. It is understood and agreed that if, in the Responding Company’s judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company’s crews shall be given by Requesting Company to Responding Company’s supervisor(s); or, when
Responding Company's crews are to work in widely separate areas, to such of Responding Company's foremen as may be designated for the purpose by Responding Company's supervisor(s).

5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the requesting company.

6. Responding Company’s safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company’s switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

   a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

   b. Employee travel and living expenses (meals, lodging and reasonable incidentals).

   c. Replacement cost of materials and supplies expended or furnished.

   d. Repair or replacement cost of equipment damaged or lost.

   e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.
f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13. Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Last update September 2005
- Section 11 and 12 updated
Edison Electric Institute
Mutual Assistance Agreement

Edison Electric Institute ("EEI") member companies have established and implemented an effective system whereby member companies may receive and provide assistance in the form of personnel and equipment to aid in restoring and/or maintaining electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable ("Emergency Assistance"). This Mutual Assistance Agreement sets forth the terms and conditions to which the undersigned EEI member company ("Participating Company") agrees to be bound on all occasions that it requests and receives ("Requesting Company") or provides ("Responding Company") Emergency Assistance from or to another Participating Company who has also signed the EEI Mutual Assistance Agreement; provided, however, that if a Requesting Company and one or more Responding Companies are parties to another mutual assistance agreement at the time of the Emergency Assistance is requested, such other mutual assistance agreement shall govern the Emergency Assistance among those Participating Companies.

In consideration of the foregoing, the Participating Company hereby agrees as follows:

(1) When providing Emergency Assistance to or receiving Emergency Assistance from another Participating Company, the Participating Company will adhere to the written principles developed by EEI members to govern Emergency Assistance arrangements among member companies ("EEI Principles"), that are in effect as of the date of a specific request for Emergency Assistance, unless otherwise agreed to in writing by each Participating Company.

(2) With respect to each Emergency Assistance event, Requesting Companies agree that they will reimburse Responding Companies for all costs and expenses incurred by Responding Companies in providing Emergency Assistance as provided under the EEI Principles, unless otherwise agreed to in writing by each Participating Company; provided, however, that Responding Companies must maintain auditable records in a manner consistent with the EEI Principles.

(3) During each Emergency Assistance event, the conduct of the Requesting Companies and the Responding Companies shall be subject to the liability and indemnification provisions set forth in the EEI Principles.

(4) A Participating Company may withdraw from this Agreement at any time. In such an event, the company should provide written notice to EEI’s Director of Security of Transmission and Distribution Operations.
(5) EEI’s Director of Security of Transmission and Distribution Operations shall maintain a list of each Participating Company which shall be posted on the RestorePower web site at www.restorepower.com. However, a Participating Company may request a copy of the signed Mutual Assistance Agreement of another Participating Company prior to providing or receiving Emergency Assistance.

__________________________________
Company Name

__________________________________
Signature

Officer Name:
Title:
Date:
SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company’s needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company’s location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company’s employees. It is understood and agreed that if, in the Responding Company’s judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company’s crews shall be given by Requesting Company to Responding Company’s supervisor(s); or, when
Responding Company's crews are to work in widely separate areas, to such of Responding Company's foremen as may be designated for the purpose by Responding Company's supervisor(s).

5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the requesting company.

6. Responding Company’s safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company’s switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

   a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

   b. Employee travel and living expenses (meals, lodging and reasonable incidentals).

   c. Replacement cost of materials and supplies expended or furnished.

   d. Repair or replacement cost of equipment damaged or lost.

   e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.
f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company.

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13. Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Last update September 2005
- Section 11 and 12 updated
Southeastern Electric Exchange

Mutual Assistance Procedures and Guidelines
February 2012

As directed by the Board of Directors of Southeastern Electric Exchange, the Mutual Assistance Committee has developed and accepted the following procedures to provide and request assistance to aid in restoring electric service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies alone. In approaching this task, committee members recognized the significant differences between work performed under normal circumstances and emergency restoration, as well as the fact that each member will at some time both require and supply emergency assistance. Therefore, members have reached understanding and agreement to adhere to the procedures and guidelines that follow without the necessity of formal contractual arrangements.

The Mutual Assistance Committee shall have responsibility for maintenance and revision of the Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines. Final acceptance of this document, as well as any future modifications, must be approved by ¾ of the appointed and serving members of the S.E.E. Mutual Assistance Committee, each operating member company having one (1) vote.

Section I
Understanding Among Members Regarding Mutual Assistance

1. Members of Southeastern Electric Exchange understand and agree:

   1.1 That members will work together to minimize risk to all parties. Responding Companies will provide assistance (personnel and equipment) on a not-for-profit basis, and Requesting Companies will reimburse Responding Companies for all expenses incurred in providing the assistance. ¹

   1.2 To adhere to and operate in accordance with the procedures contained in this document (the Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines).

   1.3 That should there be any conflict in procedures and guidelines contained in the S.E.E. Mutual Assistance Procedures and Guidelines and other regional or national mutual assistance agreements, guidelines, principles, or procedures, S.E.E. members will adhere to the procedures approved by the S.E.E. Mutual Assistance Committee when assisting or requesting assistance from fellow members through the Joint Mobilization Conference Call Procedure outlined in this document.

¹ In this document the terms Responding Company and Requesting Company refers to both the company and its employees.
2. Personnel Safety

2.1 Whether providing or receiving assistance, personnel safety will be the preeminent objective and responsibility of all participants.

2.2 The Requesting Company agrees to make every effort to avoid moving Responding Company personnel into harms way during the initial, first-wave mobilization.

2.3 Responding Company will follow its own safety rules, except as noted in paragraphs 2.6 and 2.7 below.

2.4 Responding Company is responsible for following its own personal protective grounding practices.

2.5 Responding Company will immediately report any and all accidents to Requesting Company (both incidence and injury).

2.6 Switching procedures will be handled as the Requesting Company designates, provided that the procedures do not violate the safety rules of the Responding Company.

2.7 Requesting Company will provide information on their switching and tagging rules. Requesting Company switching/blocking tags will be used.

2.8 Security personnel requirements shall be discussed and mutually agreed upon by the Requesting and Responding Companies prior to deployment of armed security personnel.

2.9 Any deployment of “Security Personnel” – armed or otherwise – must comply with Federal, State, and Local regulations.

3. Maintenance of Contact Roster

3.1 In order to facilitate efficient communication and response, S.E.E. member utilities will share the following information:

- The names, contact numbers (work phone, home phone, cellular phone, and pager), and e-mail addresses for three (3) individuals authorized to participate in Joint Mobilization Conference Calls.
- If available, the telephone number for the 24-hour operations / dispatch center for the member company.
- If available, a satellite telephone number for the 24-hour storm or operations / dispatch center.
- If available, a corporate storm / emergency center 24-hour telephone number, if different from the 24-hour operations / dispatch telephone number.

3.2 The Southeastern Electric Exchange office will be responsible for maintaining and updating the Member Company Contact Roster at least every three months.
4. Code of Conduct

4.1 Whether providing or receiving assistance, all personnel will be expected to conduct themselves in a professional and responsible manner.

5. Communication With Contractors

5.1 Members understand the need for clear communication with contractors working on their systems and are encouraged to explain the joint mobilization process discussed in this document.

6. Definition of Emergency Assistance Period

6.1 Members agree that the emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company’s needs. This includes any request for the Responding Company to prepare its employees and/or equipment for travel to the Requesting Company’s location but to await further instructions before departing. This preparation time should begin when normal work activities for Responding Company stop and preparations dedicated to supporting the off system effort begin. Except as noted in paragraph 6.3, the emergency assistance period shall terminate when such employees and/or equipment have returned to their point of origin and after a reasonable time required preparing the equipment for return to normal activities (e.g. cleaning trucks, restocking minor materials, etc.).

6.2 The length of stay by Responding Company personnel will be mutually agreed to by both companies. Generally, this period should not exceed 14 consecutive days, including travel time to the work area and return to the point of origin. When mutual assistance assignments go beyond this time frame, S.E.E. members agree that Responding Company personnel will usually be changed out (rotated) rather than take extended reset periods (days off). Responding and Requesting companies may agree upon exceptions to this procedure.

6.3 It is understood and agreed that if Responding Company’s or its Holding Company’s system is threatened during any time after it has mobilized to provide mutual assistance, any part or all of the Responding Company’s native and contract workforce may be recalled. In these instances:

- It is understood and agreed that the decision to terminate assistance and recall employees lies solely with the Responding Company.

- If recall of Responding Company’s workforce becomes necessary, the Requesting Company will be responsible for all expenses incurred by Responding Company until the Responding Company returns home and vehicles are cleaned and stocked for normal work activities.

- If Responding Company’s workforce is recalled to another of the Responding Company’s locations other than their original point of origin, the Requesting Company will be responsible for travel costs to the alternate location not to exceed that which would have been incurred had the workforce returned to their original point of origin.
Section III
The Joint Mobilization Conference Call Procedure

7. Purpose and Rationale for Joint Mobilization Call Procedures

7.1 The following procedures are intended to enhance and in no way hamper the mobilization goals of member companies during emergencies.

7.2 Because response time is critical in emergency situations, the Joint Mobilization Conference Call provides a mechanism that allows members to quickly request assistance and identify the number and status of all available regional resources.

7.3 The conference call format should:

- Provide members with the opportunity to understand the entire scope of the emergency situation, including the number of companies expecting to be impacted and the potential damage to each.
- Allow members to discuss and evaluate weather forecasts from different sources.
- Result in the most efficient, effective and equitable allocation of available resources while mitigating the financial risk associated with early mobilization of resources.


8.1 Members agree to adhere to the procedures contained in this section to request, identify and mobilize emergency mutual assistance resources. The understood exception being when an event impacts a single member utility and the impacted utility anticipates a short restoration time requiring assistance from only neighboring (adjacent) utilities. In this instance, the impacted member may contact neighboring utilities directly to arrange assistance. However, because emergency events tend to expand and impact more than one utility over time, members are encouraged to use the Joint Mobilization Conference Call procedures described below for all mutual assistance requests.

8.2 Members understand and agree that participation on Joint Mobilization Conference Calls is restricted to employees of member companies of Southeastern Electric Exchange, unless otherwise agreed by members of the Mutual Assistance Committee.

8.3 Members understand that conversations between member utilities during Joint Mobilization Conference Calls may be confidential and proprietary. Therefore, with the exception of general deployment data / information, members agree not to share or release any information shared between member utilities during Joint Mobilization Conference Calls unless mutually agreed.
9. Initiation of the Joint Mobilization Conference Call

9.1 Typically, the member that expects to be impacted first by an event will initiate the conference call.

9.2 Members agree to initiate a conference call anytime they experience or are threatened by an event so significant that they anticipate needing resources beyond the capabilities of their neighboring (adjacent) utilities to restore their system.

9.3 Procedure for initiating the conference call:

- During normal business hours, the initiating member will notify any S.E.E. staff member (phone number 404-233-1188) that they wish to hold a conference call for storm response, give the staff member the toll-free conference call number, date, and time for the call (specifying time zone). S.E.E. will contact all members via e-mail, providing conference call information and confirm all members’ participation. After every call, S.E.E. will send out an e-mail providing a summary of the conference call discussion.

- After normal working hours and on weekends, members initiate the call by contacting the Executive Director of S.E.E., at home or on his cell phone. The Director will contact members as described above. If the S.E.E. Director cannot be reached, the initiating member will use the S.E.E. Mutual Assistance Contact Roster to contact members directly.

10. Responsibilities of Company Initiating Conference Call

10.1 The company initiating the conference call will designate an individual to serve as moderator for the conference call. The moderator will:

- Call the roll of member companies.
- Present the weather forecast for his / her company service territory. At their discretion, the initiating company may have a weather consultant present the current forecast.
- Ask other members for input regarding the weather forecast / predictions.
- Present an estimate of predicted impact / damages and when these are expected to occur. If the event is large enough to impact more than one member’s service territory, the moderator will ask other members for their projected damage assessments.
- Present an estimate of resources needed. If the event is large enough to impact more than one member’s service territory, the moderator will ask other members for their projected resource needs.
- By roll call, ask all non-impacted members to state the numbers of resources available to assist once their territories are no longer threatened.
- When appropriate, the moderator will lead discussion of staging areas to be used by assisting companies; transportation concerns, such as evacuation orders, fuel availability, DOT exemptions, etc.; and, the availability of non-member resources that may be available to assist impacted members.
- Keep the call moving and minimize the length of the call as much as possible.
- If requested, notify non-S.E.E. members via the EEI Restore Power list serve.
- Set the date and time for future conference calls.
11. Responsibilities of Non-Initiating Members Participating In Conference Calls

11.1 Members agree not to release or dispatch ANY resources (contract or native) unless committed to and confirmed by a Requesting Company. It is understood that Responding Companies’ territories must be free from significant threat before resources can be committed and dispatched.

11.2 On the first Joint Mobilization Conference Call, non-threatened / non-impacted members will be prepared to specify the numbers of their employee and contractor distribution line, transmission line, vegetation management, and damage assessment personnel available to assist impacted companies, including an estimate of when these resources can be dispatched. If Requesting Companies identify needs in other areas (such as IT, safety, etc.), assisting members will be given time (usually 24 hours) to identify available resources in these additional areas.

11.3 To enhance safety and flexibility, upon request non-threatened / non-impacted members will be prepared to identify staging areas available in their territories.

11.4 Upon request non-threatened / non-impacted members will assist with DOT exemptions for crews traveling through their service territories.

12. Resource Allocation and Mobilization

12.1 When more than one company has requested emergency assistance, all members understand and agree that it is the responsibility of the Requesting Companies to agree upon the allocation of available first wave and subsequent member company resources.

12.2 Members agree that, in general, resources will be allocated on the basis of severity of need, based on:
   - Predicted impact – percentage / degree of system loss and estimated time customers will have been without power.
   - Storm timing – which company will be first impacted.
   - Travel time.
   - Availability of other non-S.E.E. member controlled resources.
   - The intent will be to allocate available resources to meet all member company needs in the most efficient and equitable manner possible.

12.3 Members agree that final dispatch of committed resources is to be coordinated directly between the Requesting Company and the Responding Company (or its contractor(s), where applicable).

13. Responsibilities of S.E.E. Coordinator

13.1 The Southeastern Electric Exchange coordinator, (usually the Executive or Assistant Director), will be responsible for notifying members of Joint Mobilization Conference Calls in accordance with paragraph 9.3.

13.2 The Southeastern Electric Exchange coordinator will be responsible for producing and distributing conference call summary notes including the S.E.E. Resource Summary spreadsheet after each conference call.
13.3 When more than one company has requested emergency assistance, the Southeastern Electric Exchange coordinator will serve as moderator of conference calls between impacted companies on which Requesting Companies will agree upon the allocation of available first wave S.E.E. resources.

Section IV

Requesting Company Responsibilities


14.1 To the extent possible, the Requesting Company is expected to clearly communicate the degree of devastation and working conditions Responding Company personnel should expect to encounter upon arrival at the emergency restoration work area.

14.2 The Requesting Company is expected to inform the Responding Company if their requirements for the maintenance of receipts differ from the procedures stated in paragraph 19.5.

14.3 To facilitate communications, the Requesting Company may opt to provide a single point of contact (Coordinator) to interact with the Responding Company.

14.4 The Requesting Company will provide the Responding Company with the name and contact information for their “company contact” as required on the RESPONDING COMPANY INITIAL INFORMATION SHEET before Responding Company personnel leave their point of origin.

14.5 Requesting Company will coordinate with their state DOT officials concerning emergency exemptions and any other transportation issues that will facilitate the Responding Company’s trip to and from the Requesting Company.

14.6 The Requesting Company is encouraged to communicate general guidelines with Responding Companies. Items covered may include labor contractual issues, safety issues, contact personnel, vehicle fueling arrangements, typical standard construction, meal and lodging arrangements, and other items that will be of benefit to the responding personnel and their supervision.

15. Requesting Company – Responsibilities During Emergency Assistance Period

15.1 The Requesting Company will establish expectations for work, including start time and duration.

15.2 The Requesting Company will provide materials unless specifically noted otherwise.

15.3 When necessary, the Requesting Company will provide a guide with communications capability, portable radios or cellular telephones to assist responding team leaders.

15.4 The Requesting Company will authorize Responding Company to use cellular phones as a method of communication. Where cellular service is unavailable, it is understood that satellite phones may be used until such time that cellular service is restored in the Requesting Company’s area.

15.5 The Requesting Company will provide vehicle security for parking areas unless specifically agreed otherwise.
15.6 With the exception of food and lodging during travel to and from the final work site, the Requesting Company will handle all food, lodging and incidental support needed by Responding Company unless both companies agree for Responding Company to handle these logistics.

15.7 Requesting and Responding companies should agree on the provision of laundry services.

15.8 Requesting Company will make and communicate provisions for Responding Company personnel to make personal long distance telephone calls during the emergency response period. For example, the Requesting Company may authorize the Responding Company to purchase pre-paid long distance calling cards for responding crew members or authorize the use of company or employee owned cellular phones for an agreed upon maximum number of minutes. As a general rule, Requesting Company agrees to allow and reimburse a maximum of 10-minutes personal long distance telephone charges per employee per day. Any personal cellular phone charges or pre-paid calling card expenses shall be included in the supporting documentation on the company’s preliminary invoice, subject to paragraph 19.5.

15.9 Requesting Company understands that the Responding Company will not incur hotel-related expenses other than lodging, unless agreed to by the Requesting Company prior to their occurrence. For example, phone calls made from rooms, room service, in-room movies, mini bar usage, etc. should not be incurred.

16. Requesting Company - Procedures for Releasing Responding Companies

16.1 During emergencies impacting more than one member company simultaneously, each Requesting Company will develop and send the S.E.E. coordinator a proposed “Release Schedule” 48-hours before releasing any contract or utility (members & non-member) crews. This release schedule will include: Names of utilities and contractors to be released, the numbers and specialty (distribution line, transmission line, vegetation, etc.) of workers from each utility and / or contractor being released, the on-site contact or the coordinator of the crews being released, and the date and approximate time the crews expect to be released.

16.2 During emergencies when Responding Company contract and / or utility resources are already deployed and working to provide restoration help to one member company and another member company (or companies) is impacted by another emergency, or, in the case of hurricanes, a second landfall of the storm, the company that obtained help first agrees to:

- NOT retain personnel solely to perform maintenance, street lighting work, or clean up type work and will aggressively work to release personnel.
- Immediately prepare a release schedule which includes details listed in paragraph 16.1 above, including projected release dates.
- Provide realistic estimated restoration times and release dates to the SEE coordinator for dissemination to the second Requesting Company (or companies). Since this could mean the difference in going days away or waiting on resources closer that may become available, it is essential that release dates be as accurate as possible. **Note:** Should the emergency situation described above develop before a Responding Company personnel arrive at the initial restoration area, these resources will be reallocated to Requesting Companies in accordance with the provisions of Section 12 and paragraph 17.3 of these procedures and guidelines.
16.3 In the emergency situation described in paragraph 16.2 above, the initial and secondarily impacted companies agree to:

- Immediately hold an “impacted companies” conference call to negotiate reallocation of the resources on the release schedule developed by the first impacted company as well as any other resources not already committed.

- Regarding personnel released by the first impacted company, secondary Requesting Companies will contact the resources (companies) allocated to them to determine if those persons will agree to re-deploy or be changed out (rotated) in accordance with paragraph 6.2.

16.4 In all emergency situations, the Requesting Company will make every effort to notify each Responding Company’s mutual assistance contact 24-hours in advance of the anticipated final release of their utility personnel.

17. Requesting Company – Responsibility for Reimbursement of Expenses And Indemnification of Responding Company

17.1 Members understand and agree that the provision of emergency mutual assistance is a not-for-profit endeavor for Responding Companies. Therefore, the Requesting Company will reimburse all costs and expenses incurred by the Responding Company in the provision of the emergency assistance for the entire emergency assistance period as defined in paragraph 6 above.

17.2 If Responding Company resources are released after mobilization but before being utilized, the Requesting Company will reimburse Responding Company for all incurred preparation and travel expenses including reasonable time required to prepare the equipment for return to normal activities after returning to their point of origin.

17.3 During emergencies impacting more than one member, Responding Company resources may be re-assigned either: en route to the Requesting Company; at an initial staging area before reaching the Requesting Company; or at the Responding Company’s final staging area. Additionally, resources may be assigned to assist a second Requesting Company after completing work for the initial Requesting Company. **Note:** In any of these instances, unless otherwise mutually agreed, the utility that receives the re-assigned Responding Company resources will be responsible for all Responding Company costs from the time of re-assignment.

17.4 Requesting Company will reimburse members for expenses incurred in the provision and management of interim staging areas (i.e. labor and miscellaneous expenses provided by the host utility to operate the staging area, but not including any Responding Company crew costs). In emergencies involving more than one Requesting Company, staging costs will be shared by Requesting Companies on a prorated basis based on the resources committed to each entering (logged into) the staging site.

17.5 Provided proper supporting documentation is included, the Requesting Company will pay all (preliminary and final) invoice(s) from Responding Company within 60 calendar days after receipt of invoice(s).
17.6 Requesting Company shall indemnify and hold Responding Company harmless from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

Where payments are made by Responding Company under a worker’s compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

17.7 In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (17.6) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent.

Section V
Responding Company – Procedures / Responsibilities

18. Responding Company – Responsibilities Prior to Mobilization

18.1 To the extent possible, the Responding Company is expected to clearly communicate the degree of devastation and working conditions that their responding employees should expect to encounter upon arrival at the emergency restoration work area.

18.2 To facilitate communications, the Responding Company may opt to provide a single point of contact (Coordinator) to interact with the Requesting Company.

18.3 Responding Company will complete and forward the RESPONDING COMPANY INITIAL INFORMATION SHEET before departing their home location.

18.4 If requested, Responding Company will provide a copy of completed PERSONNEL LISTING FORM as soon as the information becomes available.

18.5 Responding Company’s telecommunications personnel shall contact Requesting Company’s telecommunications personnel and local FCC authorities to make any temporary telecommunications arrangements.

18.6 Prior to traveling, Responding Company will reach agreement with the Requesting Company regarding the provisions for Responding Company personnel to make personal long distance telephone calls during the emergency response period as described in paragraph 15.8 above. This agreement should preclude any telephone charges from any lodging facility by the Responding Company personnel, except in case of emergency local 911 calls.
18.7 Responding Company agrees not to load extra emergency stock on trucks unless specifically requested by the Requesting Company.

18.8 When Responding Company’s available contractor resources have been allocated to a Requesting Company through the Joint Mobilization Conference Call procedures, the Responding Company will:

- Provide Requesting Company with contact information for their on-site contractors.
- Alert their contractors that their assistance has been requested and that they will be contacted by the Requesting Company.
- Give their contractors the Requesting Company contact information.
- Encourage their contractors to respond to the S.E.E. member’s request for help with all contract crews being released from the Responding Company’s work site.

19. Responding Company – Responsibilities During Emergency Assistance Period

19.1 Responding Company will handle all communication needs within their teams. This could include acquiring additional communications equipment, such as portable repeaters, to ensure continuous communication capabilities.

19.2 The Responding Company will be responsible for performing normal maintenance on their vehicles and equipment during the emergency assistance period and this work will be covered in their standard hourly/daily rates.

19.3 Responding Company will maintain daily records of time and expenses for personnel and equipment. This documentation will be provided with their preliminary invoice.

19.4 When the Requesting Company has provided specific guidance in advance that differs from that in paragraph 19.5, the Responding Company will maintain and furnish the requested documentation of expenses with their preliminary invoice.

19.5 Unless otherwise agreed prior to mobilization, members agree that Responding companies will maintain and furnish upon request receipts for all individual expenses / purchases made during the emergency assistance period in accordance with the IRS requirements in effect at the time assistance is requested.

20. Responding Company – Responsibilities End Of Emergency Assistance Period

20.1 Responding Company should submit their "preliminary invoice" to Requesting Company within 60 calendar days from date released by the Requesting Company. Responding Company will provide supporting documentation at the time the preliminary invoice is mailed. Requesting Utility should receive final invoice within 90 calendar days from invoice date of preliminary invoice. An S.E.E. INVOICE COVER SHEET shall be included with the Responding Company's billing package.

20.2 Responding Companies agree to maintain auditable records of billed expenses for emergency mutual assistance sufficient to satisfy the legal / statutory requirements and obligations incumbent upon the Requesting Company.
Southeastern Electric Exchange

Mutual Assistance Procedures and Guidelines
February 2012

As directed by the Board of Directors of Southeastern Electric Exchange, the Mutual Assistance Committee has developed and accepted the following procedures to provide and request assistance to aid in restoring electric service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies alone. In approaching this task, committee members recognized the significant differences between work performed under normal circumstances and emergency restoration, as well as the fact that each member will at some time both require and supply emergency assistance. Therefore, members have reached understanding and agreement to adhere to the procedures and guidelines that follow without the necessity of formal contractual arrangements.

The Mutual Assistance Committee shall have responsibility for maintenance and revision of the Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines. Final acceptance of this document, as well as any future modifications, must be approved by % of the appointed and serving members of the S.E.E. Mutual Assistance Committee, each operating member company having one (1) vote.

Section I

Understanding Among Members Regarding Mutual Assistance

1. Members of Southeastern Electric Exchange understand and agree:

1.1 That members will work together to minimize risk to all parties. Responding Companies will provide assistance (personnel and equipment) on a not-for-profit basis, and Requesting Companies will reimburse Responding Companies for all expenses incurred in providing the assistance. ¹

1.2 To adhere to and operate in accordance with the procedures contained in this document (the Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines).

1.3 That should there be any conflict in procedures and guidelines contained in the S.E.E. Mutual Assistance Procedures and Guidelines and other regional or national mutual assistance agreements, guidelines, principles, or procedures, S.E.E. members will adhere to the procedures approved by the S.E.E. Mutual Assistance Committee when assisting or requesting assistance from fellow members through the Joint Mobilization Conference Call Procedure outlined in this document.

¹ In this document the terms Responding Company and Requesting Company refers to both the company and its employees.
4. Code of Conduct

4.1 Whether providing or receiving assistance, all personnel will be expected to conduct themselves in a professional and responsible manner.

5. Communication With Contractors

5.1 Members understand the need for clear communication with contractors working on their systems and are encouraged to explain the joint mobilization process discussed in this document.

6. Definition of Emergency Assistance Period

6.1 Members agree that the emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. This includes any request for the Responding Company to prepare its employees and/or equipment for travel to the Requesting Company's location but to await further instructions before departing. This preparation time should begin when normal work activities for Responding Company stop and preparations dedicated to supporting the off system effort begin. Except as noted in paragraph 6.3, the emergency assistance period shall terminate when such employees and/or equipment have returned to their point of origin and after a reasonable time required preparing the equipment for return to normal activities (e.g. cleaning trucks, restocking minor materials, etc.).

6.2 The length of stay by Responding Company personnel will be mutually agreed to by both companies. Generally, this period should not exceed 14 consecutive days, including travel time to the work area and return to the point of origin. When mutual assistance assignments go beyond this time frame, S.E.E. members agree that Responding Company personnel will usually be changed out (rotated) rather than take extended reset periods (days off). Responding and Requesting companies may agree upon exceptions to this procedure.

6.3 It is understood and agreed that if Responding Company's or its Holding Company's system is threatened during any time after it has mobilized to provide mutual assistance, any part or all of the Responding Company's native and contract workforce may be recalled. In these instances:

- It is understood and agreed that the decision to terminate assistance and recall employees lies solely with the Responding Company.
- If recall of Responding Company's workforce becomes necessary, the Requesting Company will be responsible for all expenses incurred by Responding Company until the Responding Company returns home and vehicles are cleaned and stocked for normal work activities.
- If Responding Company's workforce is recalled to another of the Responding Company's locations other than their original point of origin, the Requesting Company will be responsible for travel costs to the alternate location not to exceed that which would have been incurred had the workforce returned to their original point of origin.
9. Initiation of the Joint Mobilization Conference Call

9.1 Typically, the member that expects to be impacted first by an event will initiate the conference call.

9.2 Members agree to initiate a conference call anytime they experience or are threatened by an event so significant that they anticipate needing resources beyond the capabilities of their neighboring (adjacent) utilities to restore their system.

9.3 Procedure for initiating the conference call:

- During normal business hours, the initiating member will notify any S.E.E. staff member (phone number 404-233-1188) that they wish to hold a conference call for storm response, give the staff member the toll-free conference call number, date, and time for the call (specifying time zone). S.E.E. will contact all members via e-mail, providing conference call information and confirm all members' participation. After every call, S.E.E. will send out an e-mail providing a summary of the conference call discussion.

- After normal working hours and on weekends, members initiate the call by contacting the Executive Director of S.E.E., at home or on his cell phone. The Director will contact members as described above. If the S.E.E. Director cannot be reached, the initiating member will use the S.E.E. Mutual Assistance Contact Roster to contact members directly.

10. Responsibilities of Company Initiating Conference Call

10.1 The company initiating the conference call will designate an individual to serve as moderator for the conference call. The moderator will:

- Call the roll of member companies.
- Present the weather forecast for his / her company service territory. At their discretion, the initiating company may have a weather consultant present the current forecast.
- Ask other members for input regarding the weather forecast / predictions.
- Present an estimate of predicted impact / damages and when these are expected to occur. If the event is large enough to impact more than one member's service territory, the moderator will ask other members for their projected damage assessments.
- Present an estimate of resources needed. If the event is large enough to impact more than one member's service territory, the moderator will ask other members for their projected resource needs.
- By roll call, ask all non-impacted members to state the numbers of resources available to assist once their territories are no longer threatened.
- When appropriate, the moderator will lead discussion of staging areas to be used by assisting companies; transportation concerns, such as evacuation orders, fuel availability, DOT exemptions, etc.; and, the availability of non-member resources that may be available to assist impacted members.
- Keep the call moving and minimize the length of the call as much as possible.
- If requested, notify non-S.E.E. members via the EEI Restore Power list serve.
- Set the date and time for future conference calls.
13.3 When more than one company has requested emergency assistance, the Southeastern Electric Exchange coordinator will serve as moderator of conference calls between impacted companies on which Requesting Companies will agree upon the allocation of available first wave S.E.E. resources.

Section IV
Requesting Company Responsibilities


14.1 To the extent possible, the Requesting Company is expected to clearly communicate the degree of devastation and working conditions Responding Company personnel should expect to encounter upon arrival at the emergency restoration work area.

14.2 The Requesting Company is expected to inform the Responding Company if their requirements for the maintenance of receipts differ from the procedures stated in paragraph 19.5.

14.3 To facilitate communications, the Requesting Company may opt to provide a single point of contact (Coordinator) to interact with the Responding Company.

14.4 The Requesting Company will provide the Responding Company with the name and contact information for their "company contact" as required on the RESPONDING COMPANY INITIAL INFORMATION SHEET before Responding Company personnel leave their point of origin.

14.5 Requesting Company will coordinate with their state DOT officials concerning emergency exemptions and any other transportation issues that will facilitate the Responding Company’s trip to and from the Requesting Company.

14.6 The Requesting Company is encouraged to communicate general guidelines with Responding Companies. Items covered may include labor contractual issues, safety issues, contact personnel, vehicle fueling arrangements, typical standard construction, meal and lodging arrangements, and other items that will be of benefit to the responding personnel and their supervision.

15. Requesting Company – Responsibilities During Emergency Assistance Period

15.1 The Requesting Company will establish expectations for work, including start time and duration.

15.2 The Requesting Company will provide materials unless specifically noted otherwise.

15.3 When necessary, the Requesting Company will provide a guide with communications capability, portable radios or cellular telephones to assist responding team leaders.

15.4 The Requesting Company will authorize Responding Company to use cellular phones as a method of communication. Where cellular service is unavailable, it is understood that satellite phones may be used until such time that cellular service is restored in the Requesting Company’s area.

15.5 The Requesting Company will provide vehicle security for parking areas unless specifically agreed otherwise.
16.3 In the emergency situation described in paragraph 16.2 above, the initial and secondarily impacted companies agree to:

- Immediately hold an "impacted companies" conference call to negotiate reallocation of the resources on the release schedule developed by the first impacted company as well as any other resources not already committed.

- Regarding personnel released by the first impacted company, secondary Requesting Companies will contact the resources (companies) allocated to them to determine if those persons will agree to re-deploy or be changed out (rotated) in accordance with paragraph 6.2.

16.4 In all emergency situations, the Requesting Company will make every effort to notify each Responding Company's mutual assistance contact 24-hours in advance of the anticipated final release of their utility personnel.

17. Requesting Company – Responsibility for Reimbursement of Expenses And Indemnification of Responding Company

17.1 Members understand and agree that the provision of emergency mutual assistance is a not-for-profit endeavor for Responding Companies. Therefore, the Requesting Company will reimburse all costs and expenses incurred by the Responding Company in the provision of the emergency assistance for the entire emergency assistance period as defined in paragraph 6 above.

17.2 If Responding Company resources are released after mobilization but before being utilized, the Requesting Company will reimburse Responding Company for all incurred preparation and travel expenses including reasonable time required to prepare the equipment for return to normal activities after returning to their point of origin.

17.3 During emergencies impacting more than one member, Responding Company resources may be re-assigned either: en route to the Requesting Company; at an initial staging area before reaching the Requesting Company; or at the Responding Company's final staging area. Additionally, resources may be assigned to assist a second Requesting Company after completing work for the initial Requesting Company. Note: In any of these instances, unless otherwise mutually agreed, the utility that receives the re-assigned Responding Company resources will be responsible for all Responding Company costs from the time of re-assignment.

17.4 Requesting Company will reimburse members for expenses incurred in the provision and management of interim staging areas (i.e. labor and miscellaneous expenses provided by the host utility to operate the staging area, but not including any Responding Company crew costs). In emergencies involving more than one Requesting Company, staging costs will be shared by Requesting Companies on a prorated basis based on the resources committed to each entering (logged into) the staging site.

17.5 Provided proper supporting documentation is included, the Requesting Company will pay all (preliminary and final) invoice(s) from Responding Company within 60 calendar days after receipt of invoice(s).
18.7 Responding Company agrees not to load extra emergency stock on trucks unless specifically requested by the Requesting Company.

18.8 When Responding Company's available contractor resources have been allocated to a Requesting Company through the Joint Mobilization Conference Call procedures, the Responding Company will:

- Provide Requesting Company with contact information for their on-site contractors.
- Alert their contractors that their assistance has been requested and that they will be contacted by the Requesting Company.
- Give their contractors the Requesting Company contact information.
- Encourage their contractors to respond to the S.E.E. member's request for help with all contract crews being released from the Responding Company's work site.

19. Responding Company – Responsibilities During Emergency Assistance Period

19.1 Responding Company will handle all communication needs within their teams. This could include acquiring additional communications equipment, such as portable repeaters, to ensure continuous communication capabilities.

19.2 The Responding Company will be responsible for performing normal maintenance on their vehicles and equipment during the emergency assistance period and this work will be covered in their standard hourly/daily rates.

19.3 Responding Company will maintain daily records of time and expenses for personnel and equipment. This documentation will be provided with their preliminary invoice.

19.4 When the Requesting Company has provided specific guidance in advance that differs from that in paragraph 19.5, the Responding Company will maintain and furnish the requested documentation of expenses with their preliminary invoice.

19.5 Unless otherwise agreed prior to mobilization, members agree that Responding companies will maintain and furnish upon request receipts for all individual expenses / purchases made during the emergency assistance period in accordance with the IRS requirements in effect at the time assistance is requested.

20. Responding Company – Responsibilities End Of Emergency Assistance Period

20.1 Responding Company should submit their "preliminary invoice" to Requesting Company within 60 calendar days from date released by the Requesting Company. Responding Company will provide supporting documentation at the time the preliminary invoice is mailed. Requesting Utility should receive final invoice within 90 calendar days from invoice date of preliminary invoice. An S.E.E. INVOICE COVER SHEET shall be included with the Responding Company's billing package.

20.2 Responding Companies agree to maintain auditable records of billed expenses for emergency mutual assistance sufficient to satisfy the legal / statutory requirements and obligations incumbent upon the Requesting Company.

Attachments:

Attachment I – Joint Mobilization Conference Call Outline
Attachment II – Responding Company Initial Information Sheet
Attachment III – Emergency Assistance Personnel Listing Form
Attachment IV – S.E.E. Invoice Cover Sheet
Statement of Understanding
And
Endorsement

The member companies of Southeastern Electric Exchange understand that they will have occasion to either provide or receive assistance in the form of personnel and equipment to aid in restoring electric service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies without assistance. For this reason, the Board of Directors of Southeastern Electric Exchange instructs and authorizes the Mutual Assistance Committee to develop and maintain operating procedures and guidelines to insure the most effective and efficient response by the entire membership when emergency assistance is requested by one or more member companies. Final acceptance of the Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines, as well as any future modifications, must be approved by ¾ of the appointed and serving members of the S.E.E. Mutual Assistance Committee, each operating member company having one (1) vote.

Further, as an officer of the Southeastern Electric Exchange member company noted below, the undersigned hereby endorses the following principles and agreements on behalf of his / her member company:

1. Whether providing or receiving assistance, personnel safety will be the preeminent objective and responsibility of all participants.

2. Member companies agree to adhere to and operate in accordance with the procedures contained in the Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines.

3. Whether providing or receiving assistance, members will work together to minimize risk to all parties. In accordance with S.E.E. procedures, responding companies will provide assistance (personnel and equipment) on a not-for-profit basis, and requesting companies will reimburse responding companies for all expenses incurred in providing the assistance. In keeping with this principle, S.E.E. members agree to abide by the indemnification provisions contained in the Southeastern Electric Exchange Mutual Assistance Operating Procedures and Guidelines.

[Signatures and dates]
October 21, 2013

VIA ELECTRONIC FILING

Joel Peck
Clerk, Virginia State Corporation Commission
Document Control Center

RE: Joint Application of Kentucky Utilities Company d/b/a Old Dominion Power Company, Louisville Gas and Electric Company, LG&E and KU Services Company, LG&E and KU Energy LLC, LG&E and KU Capital LLC, PPL Corporation, PPL Electric Utilities Corporation, and PPL Services Corporation for Authority to Engage in Affiliate Transactions and to Enter Into Utility Services Agreements, Pursuant to Chapter 4 of Title 56 of the Code of Virginia, § 56-76 et seq.
Case No. PUE-2011-00095

Dear Mr. Peck:

Pursuant to ordering paragraph (7) of this Commission’s Order Granting Authority dated November 14, 2011, attached please find and accept for filing Kentucky Utilities Company d/b/a Old Dominion Power Company’s Utility Services Agreement (Mutual Assistance / Emergency Assistance Agreement) in the above-referenced case.

Should you have any questions, please do not hesitate to contact me.

Yours very truly,

Kendrick R. Riggs

KRR:cc
Attachment
Joel Peck  
October 21, 2013  
Page 2

cc: Raymond L. Doggett Jr., Associate General Counsel  
    Susan D. Larsen, Director, Division of Utility Accounting & Finance  
    William F. Stephens, Director, Division of Energy Regulation  
    C. Meade Browder, Senior Assistant Attorney General
UTILITY SERVICES AGREEMENT

This Utility Services Agreement (this “Agreement”) is entered into as of the 21st day of October, 2013, by and between Kentucky Utilities Company (“KU/ODP”), a public utility organized under Virginia and Kentucky law and doing business in Virginia as Old Dominion Power Company, and PPL Electric Utilities Corporation (“PPL Electric”), a public utility organized under Pennsylvania law.

WHEREAS, KU/ODP is an indirect subsidiary of PPL Corporation;

WHEREAS, PPL Electric is a direct, wholly owned subsidiary of PPL Corporation;

WHEREAS, KU/ODP and PPL Electric are utility companies that provide electric service within their respective service territories;

WHEREAS, KU/ODP and PPL Electric may receive from and provide assistance to each other in the form of personnel, equipment, and services to aid in restoring and/or maintaining electric utility service when such service has been disrupted by the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable (“Emergency Assistance”); and

WHEREAS, KU/ODP and PPL Electric believe that it is in the public interest and the interests of each company to provide for such an arrangement.

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. GOODS AND SERVICES. From time to time during the term of this Agreement, KU/ODP and PPL Electric may supply Emergency Assistance to one another. Such Emergency Assistance will be provided only (a) upon request, (b) when the requesting party (“Requesting Company”) believes in good faith that the transaction will benefit the Requesting Company and its native-load customers, and (c) the responding party (“Responding Company”) believes in good faith that the Emergency Assistance can be provided without material detriment to the Responding Company and its native-load customers.

2. COMPENSATION AND ALLOCATION.

A. The Emergency Assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company’s needs. The Emergency Assistance period shall terminate when such employees and/or equipment have returned to the Responding Company.

B. The Requesting Company shall reimburse the Responding Company for all costs and expenses incurred by the Responding Company as a result of furnishing emergency assistance. The Responding Company shall furnish documentation of
expenses to the Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

(i) Employees' wages and salaries for paid time spent in the Requesting Company's service area and paid time during travel to and from such service area, plus the Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social retirement benefits, all payroll taxes, workers' compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

(ii) Employee travel and living expenses (meals, lodging and reasonable incidentals).

(iii) Replacement cost of materials and supplies expended or furnished.

(iv) Repair or replacement cost of equipment damaged or lost.

(v) Charges, at rates internally used by the Responding Company, for the use of transportation equipment and other equipment requested.

(vi) Administrative and general costs, which are properly allocable to the Emergency Assistance, to the extent such cost are not chargeable to the foregoing subsections.

3. TERMINATION AND MODIFICATION. Either party to this Agreement may terminate this Agreement by providing 60 days written notice of such termination to the other party.

This Agreement is subject to termination or modification at any time to the extent its performance may conflict with any rule, regulation or order of the Federal Energy Regulatory Commission adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

The authorization for this Agreement shall expire at the conclusion of five years beginning on the date this Agreement is given final approval by the Virginia State Corporation Commission and the Pennsylvania Public Utility Commission, whichever occurs later, unless the respective Commissions extend their authorizations.

4. BILLING AND PAYMENT. Payment for services provided by either party to this Agreement shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of KU/ODP and PPL Electric. Billing will be made after the work is completed and all actual costs have been accumulated with remittance due within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the date of the bill at annual rate of A1/P1 30-day Commercial Paper.
5. **INDEMNIFICATION.** The Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which the Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing Emergency Assistance and whether or not due in whole or in part to any act, omission or negligence of the Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workers' compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing Emergency Assistance, the Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

6. **NOTICE OF INDEMNIFICATION.** In the event any claim or demand is made or suit or action is filed against the Responding Company alleging liability for which the Requesting Company shall indemnify and hold harmless the Responding Company under Section 5 above, the Responding Company shall promptly notify the Requesting Company thereof, and the Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. The Responding Company shall cooperate with the Requesting Company’s reasonable efforts to investigate, defend and settle the claim or lawsuit.

7. **NOTICE.** Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

A. To KU/ODP:
   
   One Quality Street
   
   Lexington, Kentucky 40507
   
   Attn: Corporate Secretary

B. To PPL Electric:
   
   2 North 9th Street
   
   Allentown, Pennsylvania 18101
   
   Attn: Gallus F. Wukitsch III

8. **GOVERNING LAW.** This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without regard to its conflict of laws provisions.

9. **MODIFICATION.** No amendment, change, or modification of this Agreement shall be valid, unless made in writing and signed by the parties hereto.
10. ENTIRE AGREEMENT. This Agreement constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof and thereto, any and all prior agreements, understandings, or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect.

11. WAIVER. No waiver by either party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

12. ASSIGNMENT. This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or either party’s rights, interests, or obligations hereunder may be made without the other party’s consent, which shall not be unreasonably withheld, delayed, or conditioned.

13. SEVERABILITY. If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed as of this 2nd day of October, 2013.

Kentucky Utilities Company

By: [Signature]
Name: Paul Gregory Thomas
Title: Vice President, Energy Delivery – Distribution Operations

PPL Electric Utilities Corporation

By: [Signature]
Name: David K. Boneberger
Title: Vice President – Distribution Operations
July 2, 2013

LGE & KU Energy LLC
Attn: John Wolf-Director Distribution Operations

Dear Mr. Wolf:

Enclosed for your review is a fully executed Mutual Aid Agreement between LGE/KU and OMU. I would like to take this opportunity to thank you and your staff for assisting OMU in the development of this agreement. Please let me know if you ever need assistance.

Sincerely,

Tim Lyons
Director of Engineering & Operations
Owensboro Municipal Utilities
LG&E KU Services
Owensboro Municipal Utilities
Mutual Aid Agreement

On occasion, LG&E and KU Services (LKE) and Owensboro Municipal Utilities (OMU) shall need to call upon each other for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that LKE and OMU are not under any obligation to furnish such emergency assistance, experience indicates that both Companies are willing to furnish such assistance when personnel or equipment are available.

The following principles are agreed to as the basis for a contract governing emergency assistance between the company requesting emergency assistance ("Requesting Company") and the company willing to furnish such assistance ("Responding Company"), when such assistance is requested between LKE and OMU:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company’s needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company’s location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, LKE and OMU should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, LKE and OMU should agree on the process for replacing or providing extra rest for the Responding Company’s employees. It is understood and agreed that if, in the Responding Company’s judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company’s crews shall be given by Requesting Company to Responding Company’s supervisor(s); or, when Responding Company's crews are to work in widely separate areas, to such of Responding Company’s supervisors as the Requesting Company may designate.
Company's foremen as may be designated for the purpose by Responding Company's supervisor(s).

5. Unless otherwise agreed by LKE and OMU, the Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the Requesting Company.

6. Responding Company’s safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company’s switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company’s employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company’s sole discretion. Responding Company shall provide a copy to Requesting Company of an employee roster, equipment roster of billable material, and emergency contact information for those persons who will be providing assistance to Requesting Company.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:
   a. Employees’ wages and salaries for paid time spent in Requesting Company’s service area and paid time during travel to and from such service area, plus Responding Company’s standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen’s compensation, employer’s liability insurance and other contingencies and benefits imposed by applicable law or regulation.
   b. Employee travel and living expenses (meals, lodging and reasonable incidentals).
   c. Replacement cost of materials and supplies expended or furnished.
   d. Repair or replacement cost of equipment damaged or lost.
   e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.
   f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part...
to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13. LKE and OMU should consider the release of contractors during restoration activities. The Responding Company shall supply the Requesting Company with contact information of the contractors (this may be simply supplying the contractors' name). The contractors will negotiate directly with Requesting Company.

14. Either party may withdraw from this agreement at any time by providing written notice to the other party. Such notice shall not affect any obligations which may have been incurred hereunder prior to the effective date of such notice or which may arise out of events occurring prior to that date. No Requesting Company may withdraw from this agreement while it is receiving assistance pursuant to the terms of this agreement.

John K. Wolfe  
Director Dist. Ops. & System Restoration  
LG&E KU Services  

Date: 6/04/13

Terry Naulty  
General Manager & CEO  
Owensboro Municipal Utilities  

Date: 6/19/13
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I. Ownership and Updates

National Response Executive Committee (NREC) Chair is responsible for ensuring that this National Response Event (NRE) Playbook is maintained current and updated with any changes during his/her tenure. This playbook will be reviewed at least annually prior to June 1st in preparation for an annual drill and the hurricane season. Following log provides the history of the changes to the playbook.

<table>
<thead>
<tr>
<th>Date of Change</th>
<th>Authorized by</th>
<th>Section(s) changed</th>
<th>Reason:</th>
</tr>
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<td>NREC After Action</td>
<td>Various</td>
<td>Updated Draft based on feedback from March 2014 Table Top Exercise</td>
</tr>
<tr>
<td>July 30, 2014</td>
<td>NREC After Action</td>
<td>Various</td>
<td>Updated Draft based on feedback from May 2014 Functional Exercise</td>
</tr>
<tr>
<td>September 11, 2014</td>
<td>NREC After Action</td>
<td>Various</td>
<td>Updated Draft based on feedback from August 2014 Functional Exercise</td>
</tr>
</tbody>
</table>

* Though this playbook is all hazards, the most likely hazard that will cause an NRE is a hurricane.
II. Scope

This playbook applies to any event for which the NRE process is activated, irrespective of the specific hazard. The NRE is activated by the CEOs (or designated officers) of requesting Edison Electric Institute (EEI) member utilities when multiple Regional Mutual Assistance Groups (RMAGs) cannot adequately support the resource requirements of the requesting utilities. The Playbook should be used by all NRE participants as a reference guide during the event and should be tested in table top and functional exercises annually. Updates to the playbook should be based on lessons learned from the after action review following actual events or exercises.

By definition, a National Response Event is an electric utility event that:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.

Once the NRE is activated, all of the available resources (line workers, tree trimmers, damage assessors, logistical support, etc.) are allocated at the national level across individual companies and RMAGs based on transparent and objective criteria.

A National Response Event will also require coordination of the Federal, State and Local response.
III. National Response Event Structure, Roles and Responsibilities

A. Structure

National Response Executive Committee (NREC)
The NREC is responsible to the Edison Electric Institute (“EEI”) Board of Directors. The NREC will provide executive leadership to develop procedures and processes covering Emergency Assistance arrangements between Participating Companies to respond to an NRE. The NREC will also review and validate a request to activate an NRE, and resolve any issues stemming from the resource allocation process.

The EEI Board of Directors will designate one Participating Company executive from each RMAG to serve as primary members of the NREC, as well as two additional executives from each RMAG (except for the Wisconsin RMAG, which shall have one primary member) to serve as first and second alternates, respectively. The EEI Board of Directors shall also, at its discretion, designate up to two additional ‘at large’ executives to serve as primary members of the NREC. Members of the NREC shall be executive level, have operations and emergency assistance experience, and possess the ability to communicate at all levels of management. No one Participating Company, or parent thereof, may have multiple members on the NREC.

The leadership of the NREC shall consist of a Chair, a Vice Chair, and a Second Vice Chair. The NREC shall annually elect a Second Vice Chair from its membership at its first meeting of each year. At that time, the Vice Chair will assume the role of Chair, the Second Vice Chair will assume the role of Vice Chair, and the newly elected Second Vice Chair shall become Second Vice Chair. All leadership roles will last one year. The three officers will rotate on a yearly cycle. Other NREC members will rotate on a three year cycle and be replaced sequentially; with the primary member rolling off, the first alternate becoming primary, the second alternate becoming the first alternate and the new second alternates designated by the EEI Board of Directors. The two ‘at large’ NREC members shall serve one-year terms and be replaced on an annual basis.

National Mutual Assistance Resource Team (NMART)
During an NRE, the NMART is responsible for collecting information regarding the scope of actual or forecasted damage, determining available and requested resources and allocating the available resources in a safe, efficient, transparent and equitable manner.

The NMART consists of the officers of the EEI Mutual Assistance/Emergency Preparedness Committee (EEI MA/EP) and one representative from each RMAG. The EEI MA/EP Co-Chairs, Vice Chair, Secretary and Secretary in Waiting will serve as the same roles in the NMART.

Edison Electric Institute
EEI serves as the industry liaison to EEI Member Company Chief Executive Officers (“CEOs”), senior government officials, federal agencies, and national organizations representing state and local interests. At the request of an EEI Member, EEI may also serve as an industry liaison to state regulatory agencies. During an NRE, EEI convenes periodic conference calls with the EEI Member Company CEOs and senior governmental officials. EEI will also serve as the investor-owned electric utility industry’s primary national information resource. EEI will provide a broad, national perspective on the event through media and public
relations activities, national stakeholder outreach, including relevant Federal agencies, social media support, and industry-wide communication and coordination to relevant stakeholders.

EEI is not a member of the NREC, but will work closely with the NREC and may participate in NREC and NMART activities as appropriate to carry out its functions. EEI will also perform the role of the EEI NRE Liaison, filling two roles: communication liaison officer to the NREC and operations liaison officer to the NREC.

EEI Chief Executive Officers
The EEI Chief Executive Officers or their designees are the primary stakeholder for the National Response Event. Individually, they may request that the NRE be activated. Working through the EEI Policy Committee on Reliability and Business Continuity (PC – RBC), they support fellow CEOs and the NREC in the NRE appeals process. Working through the EEI PC – RBC, they receive daily updates on the NRE.

**Figure 1 NRE Roles and Responsibilities**

**B. NRE Roles and Responsibilities**

In addition to NREC, NMART, EEI and EEI CEOs all of which are described in Section III A above, the following are the key roles/groups responsible for executing the NRE resource allocation process:

**EEI CEOs and Member Companies**

EEI CEOs (or designees)
All EEI member CEOs or their designees are eligible to request an NRE. The EEI CEOs are responsible for:

- Individually can request an NRE
- Collectively support the NRE process by providing counsel through EEI, the EEI Policy Committee on Reliability and Business Continuity and the NREC.

**Requesting Companies**
Requesting companies are those companies that are either under a threat of a major event or have been impacted and are looking for mutual assistance resources.

**Responding Companies**
Responding companies are those companies that have not been affected by the event itself and/or are in position to provide resources to assist in the restoration effort at other utility companies.

**NREC**

**NREC Chair**
At the beginning of the first NREC meeting each year, the NREC First Vice Chair is elevated to the NREC Chair. The NREC chair shall lead the NREC throughout the NRE unless the NREC Chair’s company is impacted by the event or there is some other potential conflict that would require the NREC First Vice Chair, Second Vice Chair or other NREC member to assume the role of the NREC Chair. The NREC Chair is responsible for:

- Work with the requesting CEO, the Policy Committee on Reliability and Business Continuity Co-Chairs and EEI and managing the activation of the NRE
- Developing situational awareness including contacting the NREC members
- Responsible for the weather forecast and safety message for each conference call
- Managing the NRE process from request to demobilization
- Interacting with CEOs
- Notifying the NMART of activation
- Managing appeals
- Coordinating with EEI
- Transferring responsibility to the Vice-Chair if Chair’s own company is impacted
- Co-locate with EEI in the event of an NRE

**NREC Vice Chair (s)**
At the beginning of the first NREC meeting each year, as the NREC First Vice Chair is elevated to the NREC Chair, and the NREC Second Vice Chair is elevated to First Vice Chair. The incoming Second Vice Chair would then be elected by the NREC. The NREC First or Second Vice Chair may assume or assist with the NREC Chair’s responsibilities.
The NREC Vice Chairs are responsible for:

- Supporting the NREC Chair
- Back filling the NREC Chair in his/her absence or if conflict of interest arises
- Co-locating with EEI in the event of a NRE.
NREC Members
The NREC members are typically executive representatives from each of the RMAGs. The NREC members include 3 executive members from 6 of 7 RMAGS (Southeastern Electric Exchange, Texas, North Atlantic, Midwest, Western, Great Lakes), 1 representative from the Wisconsin RMAG and 2 at-large members. The NREC members are responsible for:

- Supporting the NREC Chair and Vice-chair
- Providing counsel during the activation and appeals process
- Supporting their RMAG and RMAG member companies throughout the NRE process

NMART
NMART Co-Chair(s)
The two NMART Co-chairs are the EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Co-Chairs. The Co-Chairs serve a two year term with one Co-Chair completing their term each year at the Annual EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Spring Meeting. At that meeting, a new Secretary-in-Waiting is elected by the EEI Operating Companies present. The NMART Co-chairs are responsible for:

- Managing the resource allocation process
- Interacting with the NREC and EEI providing information and counsel
- Travelling to EEI or the NREC co-location site
- Potentially acting as the NMART liaison to the NREC

NMART Vice-Chair
The NMART Vice Chair is the EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Vice Chair. The Vice Chair serves a one year term, completing the term each year at the Annual EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Spring Meeting, at which time the Vice Chair is elevated to one of the Co-Chair positions. The NMART vice-chair acts as a backup and resource to the NMART Co-Chairs.

NMART Secretary
The NMART Secretary serves a one year term, completing the term each year at the Annual EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Spring Meeting, at which time the Secretary is elevated to Vice Chair. The NMART Secretary is responsible for:

- Documenting all aspects of the NMART process
- Supporting the NMART Co-chairs
- Consolidating all the inputs from templates into the Resource Allocation Tool
- Managing the resource allocation tool
- Populating the dashboards in support of the NMART and NREC.

NMART Secretary-in-Waiting
The NMART Secretary in Waiting is elected annually by the EEI operating companies present. The NMART Secretary-in-Waiting is responsible for:

- Documenting all aspects of the NMART process
- Supporting the NMART Co-chairs
- Consolidating all the inputs from templates into the Resource Allocation Tool
- Managing the resource allocation tool
- Populating the dashboards in support of the NMART and NREC.
NMART Liaison to the NREC
At the time of the event, NMART will assign at least one member of the NMART’s officers (NMART Co-Chairs, Vice Chair, or Secretary) to serve as a liaison to NREC. The NMART Liaison is responsible for:

- Maintaining a deep understanding of the NMART process and allocation decisions
- Co-locate with the NREC Chair during the event
- Be responsible for providing updates and information on allocation decisions to the NREC and the EEI Liaison

NMART Analytic Team
The Analytic Team is an ad hoc group made up of various members of the NMART team possibly including one of the co-chairs, the analyst, possibly the secretary and some members of the RMAGs. The Analytic Team will consist of at the minimum three members during an event; however, the number and makeup of the team members may change depending on the size of the event, specific companies affected by the event and stage of the restoration. The NMART Analytic Team is responsible for:

- Looking at the formula outputs, subjective factors and use experience to make the first recommendations on resource allocations to requesting companies.
- Ensuring that the allocations are logical and assist in answering questions by the NREC.
- Managing the resource allocation tool
- Supporting the NMART process
- Collecting data from the RMAGs

Regional Mutual Assistance Groups (RMAGs)
The RMAGs are governed by their own by-laws and participate willingly in the NRE process. They appoint their own RMAG leadership to represent the RMAGS on an annual basis. Their role as part of the NRE includes:

- Facilitating the data gathering from the utilities
- Participating in the process of matching the mutual assistance resources that were assigned to that RMAG to those requesting companies that have designated it as the “Home” RMAG
- RMAGs are not conducting any re-allocations of the resources during an NRE
- Declaring a “Home RMAG” annually

EEI†
EEI Crisis Management Officer
The EEI Crisis Management Officer is defined in the EEI Crisis Management Plan. The officer is responsible for:

- Receiving a request for activation from an EEI CEO
- Notifying the NREC Chair
- Supporting the activation process by communicating with the NREC Chair and the impacted CEO
- Convening calls for the NREC

† All EEI Crisis Operations or Crisis Communication positions are defined in the relevant EEI response plans. Their roles in the NRE are in addition to the responsibilities that are listed in the EEI plans.
EEI Operations Liaison
The EEI Operations Liaison is responsible for:
- Interacting with the NREC and the NMART to support operational needs of the industry
- Participates in all conference calls
- Communicating these needs to Federal and national governmental officials
- Maintaining operational situational awareness for EEI

EEI Communications Liaison
The EEI Communication Liaison is responsible for:
- Interacting with the NREC and the NMART to support communication needs of the industry, specifically the NRE
- Communicating these needs to external stakeholders
- Working with the NREC to ensure that NRE communications are accurate
IV. National Response Event Process and Functions

A. Overview

The NRE resource allocation process can be executed within the same business day if a NRE is declared before noon Eastern Standard Time. If the NRE is declared after noon or on the weekend, the process will be executed within the subsequent day. Below is the target timeline for daily NRE activities:

Figure 2 First Day Example Timeline - Early Activation

In the event that a NRE is requested after noon on the first day, there will be a modified structure to the activities, calls and deliverables for the first and second day. Whenever possible and where it will make a difference in the deployment of resources, the Resource Allocation process shall happen on the same day as the activation.

Figure 3 First Two Days Example Timeline - Late Activation
Figure 4 Every Day Following Activation Timeline

<table>
<thead>
<tr>
<th>Time</th>
<th>Activity/Deliverable</th>
</tr>
</thead>
<tbody>
<tr>
<td>09:00</td>
<td>NMART Call to request resource and factor data from utilities</td>
</tr>
<tr>
<td>12:00</td>
<td>Utilities submit resource requests, factors and resource offers</td>
</tr>
<tr>
<td>13:00</td>
<td>Run initial allocation based on quantitative formula</td>
</tr>
<tr>
<td>14:00</td>
<td>Finalize allocation including qualitative factors</td>
</tr>
<tr>
<td></td>
<td>- Provide allocation information to NREC</td>
</tr>
<tr>
<td></td>
<td>- Provide matching spreadsheets to the RMAGs</td>
</tr>
<tr>
<td>14:30</td>
<td>NREC Convenes Conference Call to Review Allocation Info</td>
</tr>
<tr>
<td>15:00</td>
<td>Complete matching of resources by RMAGs</td>
</tr>
<tr>
<td>15:30</td>
<td>Impacted EEI CEOs Call (no government officials)</td>
</tr>
<tr>
<td>16:30</td>
<td>All EEI CEOs Call (no government officials)</td>
</tr>
<tr>
<td>17:15</td>
<td>EEI CEOs and Federal Government Officials Call</td>
</tr>
</tbody>
</table>

Table 1 Example Timing of Daily Calls and Deliverables

<table>
<thead>
<tr>
<th>Ideal Timing (Eastern Time)</th>
<th>Activity/Deliverable</th>
</tr>
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<tbody>
<tr>
<td>09:00</td>
<td>NMART Call to request resource and factor data from utilities</td>
</tr>
<tr>
<td>12:00</td>
<td>Utilities submit resource requests, factors and resource offers</td>
</tr>
<tr>
<td>13:00</td>
<td>Run initial allocation based on quantitative formula</td>
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<tr>
<td>14:00</td>
<td>Finalize allocation including qualitative factors</td>
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<td>14:30</td>
<td>NREC Convenes Conference Call to Review Allocation Info</td>
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<tr>
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<td>Complete matching of resources by RMAGs</td>
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<td>Impacted EEI CEOs Call (no government officials)</td>
</tr>
<tr>
<td>16:30</td>
<td>All EEI CEOs Call (no government officials)</td>
</tr>
<tr>
<td>17:15</td>
<td>EEI CEOs and Federal Government Officials Call</td>
</tr>
</tbody>
</table>
B. Activation and Mobilization

Any utility CEO or his/her designee can request NRE to be activated. The primary path for requesting the NRE activation involves a CEO or their designee contacting EEI to request activation of an NRE:

- A requesting CEO (or a designee) contacts EEI President or designee to discuss the need for an NRE activation.
- EEI then hosts a call with the requesting CEO, the NREC Chair and the CEO Policy Committee on Reliability and Business Continuity Co-Chairs to discuss the CEO’s request.
- The NREC Chair then makes a decision.
- The NREC Chair will either:
  1. Decide to activate the NRE
  2. Decide not to activate the NRE
  3. Wait 6 hours and reconsider the decision

**National Response Event Activation Criteria**

The request for activating the NRE should meet the following criteria regarding the actual/forecasted event:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.

**National Response Event Activation Steps**

When the decision to activate NRE is made, the NREC Chair will:

1. Call the NREC Vice Chair and Second Vice Chair to inform them that NRE was activated;
2. Contact the EEI MA/EP Co-Chairs to activate the NMART;
3. Set up the initial conference call with the NREC leadership, EEI Operations Officer and the EEI MA/EP Co-Chairs (this call should take place within 2 hours of the activation);
4. Determine the daily NRE call schedule (typically an hour before the CEO briefings start). (SEE timeline Section IV, A Table 1)

The contact information for all the key NRE roles is provided in the Appendix B and the sample agenda for the initial NRE call and subsequent daily calls is included in the Appendix A of this playbook.
Figure 5 NRE Activation Process Map
C. Resource Allocation Methodology

National Response Event Resource Allocation Guiding Principles

Voluntary Participation: Utility participation will remain voluntary and will not undermine a utility’s ability to retain local control of respective operations while benefiting from outside support.

Full and Reciprocal Participation: Utilities requesting mutual assistance during a NRE will offer assistance in future events proportional to their size and abilities, recognizing that great geographical separation may limit opportunities to share in all but the most catastrophic events. There will be a standing offer that each company will set and which will be available for support unless the company is threatened.

Resource Transparency: Requesting companies will disclose all available resources, including their own personnel, full time sustaining contractors, parent/sister company resources and any other resources secured in the reported mutual assistance resource counts.

Coordinate Release of Resources: Companies agree not to release or dispatch any resources unless committed to and the need confirmed by the requesting member company. It is understood that the responding member company’s territories must be free from significant threat before resources (company and contractor) can be committed and dispatched.

Situational Awareness: Requesting companies will communicate to responding companies’ personnel regarding the degree of devastation in the emergency restoration work area and expected work conditions. Requesting companies will communicate general guidelines with responding companies, such as labor contractual issues, safety issues, contract personnel, vehicle fueling arrangements, typical standard construction, meal and lodging arrangements, etc.

National Response Event Resource Allocation Guidelines

Since NRE events involve a large number of companies, the allocation process will adhere to the following guidelines that are critical to success for all utilities:

- **Home RMAG declaration**
  - Each Member Company with multiple OpCos in multiple RMAGs will declare a "Home RMAG" and make requests and/or provide information through their “Home RMAG” only.
  - The “Home RMAGs” are declared annually and are listed in Appendix B

- **Resource Transparency**:
  - Each operating company will work with their respective Home RMAG to prepopulate company resources (including internal and contractor) on the property;
  - Each company (responding/requesting) will complete required information sheets and submit in a timely manner;
  - Utilities will report accurate and total numbers of resources secured to support restoration (including all company and off-system resources, contractors and internal resources);
  - Utilities will report the most accurate and current customer outage information available – projected or actual; and,
  - All participants in the NRE process will have access to information used in the allocation process resulting allocations.
### Equitable Allocation

- Any parent company will retain full control of all of its operating company resources throughout an NRE and will be able to deploy them among its operating companies as needed;
- The allocation methodology will include a quantitative or formulaic solution that will be further refined by qualitative factors:
  - Formula will be simple and transparent, and
  - Refinement approach will be documented and consistent;
- Actual outages carry a higher priority than projected outages;
- Pre-staging will be limited to the first wave of support, unless the NMART and NREC believe that the forecasted threat requires mobilization of larger number of resources;
- Reallocations of resources during the event will focus on redistributing those resources that have been released from the utility they were supporting.
  - Reallocation of resources that have been committed but may not yet be engaged in the physical restoration will be kept to a minimum during an event, and
  - Reallocation of resources actively engaged in restoration will be extremely rare and a measure of last resort to correct a critical resource deficiency. Any reallocation will be a subject to the agreement by the utilities affected by the decision.

### Continuous Improvement

- Documentation must be maintained at a level to provide sufficient insight for after-action review (AAR); and,
- The allocation tool will serve as a repository for manpower requests and allocations.

The resource allocation methodology consists of three key components: (1) allocation formula; (2) refinement based on other emerging circumstances; and (3) matching of resources to the specific company needs.

**Resource Allocation Formula**

The resource allocation formulas will be different for pre and post impact. Pre-impact allocations are limited and challenged by weather forecast error, damage model error and degree to which mutual assistance crews can be placed on productive assignments on day one of restoration. These challenges do not exist post-impact allowing a more rigorous quantitative allocation methodology. For mixed events, where some utilities have active restoration efforts and others remain under threat, both pre and post impact methods will have to coexist under the direction of the NMART with oversight from the NREC.

**Pre-event Formula**

Prior to the hazard striking a service territory and causing damage – “pre-event”, the resources will be allocated to each requesting utilities, through the RMAGs, proportional to their request for resources. It is expected that at this stage only the initial wave of the resources will be mobilized and that a large number of utilities will be holding resources, which will become available once the weather system has dissipated. It is probable that all requests will not be met; however, the pre-event allocation contemplates providing enough assistance to reinforce utility response to those threatened during impact and quickly deliver significant support to areas actually impacted under the outage formula.
Outage Formula

The post-event resource allocation formula is based on the extent of damage and the impact of damage on electric customers. The two variables that are used in the formula are:

1. Customers out – portion of customer outages experienced by one utility as percent of the total customers out reported by all companies requesting resources.
2. Cases of Trouble – portion of the cases of trouble (locations) experienced by one utility as the percent of total cases of trouble reported by all companies requesting resources.

The current formula is based on the weighted average of the percentages associated with these two variables, where the customers out of power are weighted 60% and portion of the trouble weighted at 40%.

Given the allocation approach, the resources will be allocated based on available resources, rather than the number of resources requested by a utility. The requested number will only serve as the upper limit of the allocation. In situations where a company requested fewer resources than what its fair share is, the extra resources will be re-distributed to other utilities with open requests.

It is important to note that the exact number ultimately received by a utility may be slightly different from the fair allocation depending on the size and type of the resource contingents made available by providing utilities and contractors. For example, if the smallest block of resources is 80 full time equivalents (FTEs), the company that was allocated 100 FTEs through the process may end up with 80 FTEs.

Dealing with a Multiple Storm Event

If there is a second event, while the industry is already mobilized under the NRE, the following processes will be used:

1. Reconvene the NMART to assess the current allocation of resources with respect to both events;
2. Execute the allocation process, using the allocation tool and refinement approach to determine fair allocation based on the new damage factors and pre-staging needs;
3. Request impacted companies from the initial event(s) to begin developing a release plan;
4. Deploy available or redeploy released resources; and,
5. Consider reallocation of resources physically engaged in restoration if necessary (last resort).

If a utility that is responding to the initial event is threatened by or affected by the secondary event, it may recall its resources. This recall will be reflected in the updated numbers during the allocation process described in step 2 above.

Refinement Approach

In order to ensure efficiency of the allocation process, NMART will consider refinements to the calculated allocation numbers by evaluating qualitative factors. While difficult to incorporate into a formula, these additional factors need to be considered in the final allocation of available resources to ensure that the industry response to a NRE best reflects the needs of all customers served by utilities and any consideration of national interest. Some qualitative factors that will be considered include, but not limited to:

- Type of damage – after a thorough damage assessment, consider factors such as wires down, poles broken, flooding issues, etc.
- Significant events/societal impacts – consider impacts to major transportation hubs, critical infrastructure, national security facilities, major societal events, elections, etc.
- Estimated Time of Restoration (ETR) – Review impacted companies’ ETRs to ensure reasonableness.
- % of customers out – Determine whether any company is disproportionately affected by the event where majority or entire customer base is affected by the outage.
- Ratio of customers out per restoration FTE – ensure that the coverage of customer outages by restoration resources is reasonable across utilities;
- Ratio of cases of trouble per FTE – ensure that the impacted companies are provided comparable coverage of cases of trouble by restoration resources;
- Ability of requesting company to receive and effectively deploy incoming resources;
- Travel route – consider situations where a responding company may be able to support restoration at another affected utility in route, if the assigned requesting utility was catastrophically impacted by the event and may not be able to begin restoration immediately (e.g., major areas are still flooded, etc.); and
- Ability of a utility to restore an area in a timely manner that had major destruction.

If refinement factors are used to adjust the calculated share, the reasoning for such use will be documented appropriately.

At least one member of the NREC will participate on the NMART resource allocation review call to gain an understanding of the allocation decisions and provide any necessary input. He/she will work closely with the NMART Liaison and raise any potential concerns around the allocation decisions during the call. These concerns should be limited only to any departures from the pre-agreed upon resource allocation process. In addition, the NMART Liaison will actively participate in the entire resource allocation process and will be able to explain the allocations to the NREC and EEI Liaisons, alert NREC of any potential issues, or request NREC input on key allocation decisions in case of an impasse.

Resource Matching

The NMART, after reviewing the data supplied by the RMAGs from both the requesting and responding companies, and after considering any mitigating factors during the refinement step, will determine the appropriate number of each category of workers to be allocated to the RMAGs. The NMART will then allocate the specific groups of resources from each responding company to the home RMAGs of the requesting companies to ensure the most efficient and effective assignments based on the distance to travel and needs. Each Home RMAG will then work with the companies to match the assisting resources to their specific needs.

In general, the resources will be matched in a manner that will limit the overall travel time and meet the logistical and other needs of the requesting companies. Factors that will be considered when matching requests with available resources include, but are not limited to:

- The type of resources needed (e.g., distribution line, transmission line, damage assessors, vegetation crews, material, etc.);
- The qualifications of the workers (e.g., hot-stick qualified, glove-hand qualified, secondary qualified, de-energized work, etc.);
- The type of equipment needed (e.g., bucket trucks, digger-derrick trucks, backyard equipment, off-road equipment, etc.);
- The level of support provided by the responding company (e.g., travel team complete with management, logistic support, vehicle mechanics, etc., or stand-alone resources without support);
Contractor resources or utility company resources;
- The estimated time of arrival at the reporting locations;
- The availability of material, lodging, fuel, and other logistical needs at the reporting location;
- Contractual agreements between responding contractors and the requesting utility (e.g., liability insurance, terms and conditions, etc.); and,
- Internal resource transfers between operating companies and regions.

Once the NMART team agrees on allocation of available resources to the RMAGs, the NMART Secretary will send a report in spreadsheet format to each requesting RMAG. The spreadsheet will provide the specific information on how many of each type of resources were allocated to requesting companies and which responding companies resources have been assigned to that specific RMAG. Each RMAG will match assigned resources to specific companies according to the numbers of resources that each company received through the NMART allocation process. RMAGs will then complete the worksheet by indicating what requesting company received which specific group of resources. Once all resources have been assigned, the RMAG will return the completed worksheet to the NMART. The NMART will consolidate the allocations across NRE participants and make the summary report available to all member companies, the NREC, and EEI.

Redeployment of Resources
During an event, as impacted companies complete their restorations, they will release the off-system resources and make them available to assist other companies that have open requests. When this does occur, the NRE will use the following process:

- Impacted utility releasing the off-system resources (IOU or contractor) will contact the home utility where the resources work day-to-day to request authorization to place the resources back into the NRE allocation pool.
- Upon authorization from the home utility, the impacted utility will submit the information about the resources being released to their home RMAG, providing the same information as any other responding utility.
- The released resources will be assigned to another requesting utility in the subsequent resource allocation decision.

D. National Response Event Resource Allocation Process Map
The detailed process map provides a graphical representation of the key activities and steps required to complete the allocation of mutual assistance resources to requesting companies during a NRE. The map includes the comments (to the right of the process diagram) that provide more detailed descriptions of each process step. The key roles are listed on the left hand side and are aligned with the process steps that those roles are responsible for performing. The actual process map is provided below.
Figure 6 NRE Overall Process Map

**Process Name:** NRE Mutual Assistance Allocation Process

**Process Description:**
This process includes the steps to allocate and re-allocate mutual assistance resources during a National Response Event (NRE).

**Process Objective:**
Ensure fast, equitable and transparent allocation and re-allocation of line, tree and damage assessment mutual assistance resources (both utility and contractors) to utilities requesting assistance in an NRE.

**Customers:**
NRE Utilities

**Remarks/Details:**
- Allocation process is carried out periodically and can also be crystallized if a large block of resources becomes available unexpectedly.
- Chair of the NRE Oversight Committee will call the Allocation Team Lead (Chair, Vice Chair, Vice Chair-Sitting in the order) if they cannot locate any member of the team can instigate first call.
- SMART Lead sets up the call to start within 2-3 hours and notifies the entire team by e-mail (use next step function to get acknowledgment). Consider outboard notification tools. Indicate the time of the call and other information in the provided template (Send notification).
- Chair will call for a one-time confirmation of bridge and meeting room. If NEE is not available use CME to supply data in number.
- Each utility will submit their template to the "home RMAG" (which is located in the state and is responsible for that area). The template provides the current number of response resources (from the homer RMAG) and status information for the NRE according to the template. The template will be reviewed by the NEE to confirm the resources to be deployed. The NEE will verify the completeness and accuracy of the template.
- The process will continue with the allocation of resources to the requesting utility according to the template.

**Steps of the Process:**
1. **Agreed with a CEO to activate NRE:**
   - Activate the resource allocation team.
2. **CEO/Utility Complaint Resolution Process:**
   - Schedule first conference call and notify RMAG team members.
3. **Request resources and factor data from utilities:**
   - Consolidate templates across RMAGs.
4. **Run initial allocation of resources by individual utility using predefined criteria:**
   - Compile allocation reports and submit to Allocation Team.
5. **Allocate resources to the Allocation Team:**
   - Make allocation based on qualitative factors.
6. **Review the allocation:**
   - Adjust allocation factors to meet needs.
7. **Review allocation for reasonability:**
   - Inform RMAG Lead and NEE of the approval and final allocation.
8. **NRE Process Communication Process:**
   - NRE Resource Allocation Process completed.
9. **Are there outstanding requests remaining:**
   - Compile event summary report and send to NREC.
10. **SMART Lead sets the call to start:**
    - Within 2-3 hours and notifies the entire team by e-mail (use next step function to get acknowledgment). Consider outboard notification tools.
11. **Chair of the NRE Oversight Committee will call the Allocation Team Lead (Chair, Vice Chair, Vice Chair-Sitting in the order):**
    - If they cannot locate any member of the team can instigate first call.
E. National Response Event Resource Allocation Process Information Requirements

In order to ensure transparent allocation process, participating companies are expected to provide specific information that will ensure equitable allocation of resources. The following information must be provided by the participating companies using the pre-defined templates.

**Requesting Company Information Requirements**

The requesting companies will provide three categories of information: (1) damage information (projected or actual) as expressed by the factors for allocation; (2) number of (non-native) resources currently secured; and (3) outstanding resource request. Below is the description of each of these categories, including the list of specific pieces of information.

**Damage Factors**

The key factors that describe the amount of damage projected or experienced by a requesting utility include:

- Total customers served (may be pre-populated) – based on the total meters served across the service territory. Does not include outdoor lighting;
- Number of customer outages – best estimate of the number of customers who are without power at a point of time. This number will come from the outage management system (OMS);
- Number of cases of trouble on distribution system – defined as the number of devices that are predicted by the OMS to be out of service;
- Number of cases of trouble on transmission system – defined as the number of locations that require physical repair in order to return to normal service;
- Projected customer outages – prior to the event, utilities that have predictive models, will provide their estimates of the number of customer outages that they expect based on the most current forecast;
- Projected cases of trouble – prior to the event, utilities that have predictive models, will provide their estimates of the number of cases of trouble that they expect based on the most current forecast; and,
- Other factors to consider – such as outages to facilities that may have regional or national impact, such as transportation hubs, large sporting events (e.g., Super Bowl, Olympics, etc.)

**Current Resources Secured (expressed in FTEs)**

The requesting companies are expected to provide the count of all of the resources by type that they have been able to secure at the time of the request. These resource numbers include:

- **Native Resources** – these are the company resources and sustaining contractors. Understanding that these numbers constantly change, the utilities will be asked to provide an estimate twice a year and those numbers will then be used during the event which include:
  - Distribution Line
  - Transmission Line
  - Tree Trimming
  - Damage Assessors
  - Network Mechanics
  - Service Mechanics
  - Underground Splicers
  - Logistics Support personnel
Non-Native Resources – this number will include any parent/sister company resources, contractor resources secured through other efforts, any resources assigned through RMAG process if that was activated in advance of a NRE and any mutual assistance resources already allocated through the NRE process which includes:

- Distribution Line
- Transmission Line
- Tree Trimming
- Damage Assessor
- Network Mechanics
- Service Mechanics
- Underground Splicers
- Logistics Support personnel
- Other

**Requested Resources (Expressed in FTEs)**

The requested resources are the numbers of resources that the a company is still looking for in order to complete its restoration. It represents the additional resources on top of those that have already been secured (under previous sections).

- Outstanding Resource Needs:
  - Distribution Line
  - Transmission Line
  - Tree Trimming
  - Damage Assessors
  - Network Mechanics
  - Service Mechanics
  - Underground Splicers
  - Logistics Support personnel
  - Other

- Maximum Travel Distance – indicates the number of days that the requesting utility is willing to pay for travel.
- Destination City
- Comments and special requests

**Responding Company Information Requirements**

The responding company will submit specific information on the resources they are able to provide to assist other utilities in the restoration effort. The numbers of resources will be provided in terms of FTEs. In order to support the transparency and fairness of the NRE, each company will define the standing offer in terms of the number of resources that it can provide depending on the level of mobilization in the first wave of support and in an “all-hands on deck” response. These numbers will be used to estimate the potential support that can be provided, while the exact numbers of available resources by type will be provided for each event. The specific event information will include:
- Line resources
  - Distribution line FTEs – include any overhead line personnel for all classifications, including servicemen, troublemen, etc.
    - Company resources
    - Contractor resources
  - Transmission line FTEs – include any overhead personnel for all classifications
    - Company resources
    - Contractor resources
- Tree trimming resources
- Network/Service/Underground resources
  - Company resources
  - Contractor resources
- Damage Assessment resources
  - Damage assessors (company)
  - Damage assessors (contract)
- Logistical support personnel
- Other resources
- Departure location – indicates the city and state from which the resources will start their travel
- Comments

**Companies That Have Met Outstanding Requests through NRE**

In order to help NMART and NREC maintain situational awareness, companies that have acquired off-system resources through NRE, but are no longer requesting additional resources (i.e., do not have any remaining outstanding requests), will be required to provide the following information using the requesting company template, for each subsequent NRE resource allocation period:

- # Customers out
- # Cases of Trouble
- Estimated Time of Restoration (ETR)
- # Non-Native Resources:
  - # Distribution Line
  - # Transmission Line
  - # Tree
  - # Damage Assessors
- # Native Resources that may become available after restoration:
  - # Distribution Line
  - # Transmission Line
  - # Tree
  - # Damage Assessors

This information will help provide valuable insight on potential resource releases at future time and provide full visibility into the allocations.
**Information Maintenance and Version Control**

In order to maintain accurate records of the allocation decisions, the Analytic Team will apply a standard naming convention for the Excel files generated throughout the resource allocation process. This standard will help maintain historical information and facilitate the tracking of the most current allocation decisions. The naming convention for the Excel files will use the following format:

<table>
<thead>
<tr>
<th>Field</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>[Year]</strong></td>
<td>4 digit format (e.g., 2013);</td>
</tr>
<tr>
<td><strong>[Storm Name]</strong></td>
<td>alphanumeric name of the storm (e.g., Sandy, MW Ice Storm 2010);</td>
</tr>
<tr>
<td><strong>[Date]</strong></td>
<td>4 digit format with the month first and date second with a dash in between (e.g., May 9 would be 0509);</td>
</tr>
<tr>
<td><strong>[Time]</strong></td>
<td>using military time (e.g., 1830);</td>
</tr>
<tr>
<td><strong>[Requesting, Responding, Allocation, Matching]</strong></td>
<td>will indicate the type of data input contained in the file and will use the appropriate term in its entirety; and,</td>
</tr>
<tr>
<td><strong>[NMART]</strong></td>
<td>Designation will be utilized only for the files containing the overall data spreadsheet maintained by the NMART. For NMART files, the type of data indication will not be used.</td>
</tr>
</tbody>
</table>

**Example of a file name:** 2013 Sandy 1023 MAMA Requesting.xls

The data field definitions are:

- **[Year]** – 4 digit format (e.g., 2013);
- **[Storm Name]** – alphanumeric name of the storm (e.g., Sandy, MW Ice Storm 2010);
- **[Date]** – 4 digit format with the month first and date second with a dash in between (e.g., May 9 would be 0509);
- **[Time]** – using military time (e.g., 1830);
- **[Requesting, Responding, Allocation and Matching]** – will indicate the type of data input contained in the file and will use the appropriate term in its entirety; and,
- **[NMART]** – Designation will be utilized only for the files containing the overall data spreadsheet maintained by the NMART. For NMART files, the type of data indication will not be used.
- The NMART Secretary shall be responsible for posting the NMART Dashboard to the NRE Workroom.

**Allocation Process Documentation**

NRE Analysis Support team will be responsible for generating and maintain the documentation related to the resource allocation process, including defining and ensuring version control of various documents, allocation decision output reports, and archiving information necessary to perform an appropriate after-action review (AAR). This documentation will be placed on the EEI NRE Workroom.

**F. Demobilization/Deactivation**

Once all of the outstanding resource requests have been met and each affected company has received the mutual assistance supported it needs, the NREC Chair will begin deactivation of the NRE process. After an NRE has been completed, any additional re-allocations of resources for that event will be conducted at the individual RMAG level.

As a part of the demobilization process, the NMART Secretary will compile all the key documentation related to the key allocation decisions made throughout the NRE and ensure that the latest version of the allocation model is archived on the NRE workroom. The EEI MA/EP Co-Chairs (NMART Co-Chairs) will then develop a summary report that describes the key decisions made and process participants.

Subsequent to each NRE, the NREC chair will schedule an after action review (AAR) with the key participants in the response effort. The purpose of this review will be to assess the response and identify any potential improvement opportunities. This review will be done in a half-day facilitated session and any actions that come out of it will be assigned to specific individuals for completion.
G. After Action Review and Process Improvement

Following an NRE or exercise, the NREC shall conduct an after action review of the NRE process and procedures to identify practices to sustain as well as any opportunities for improvement. The NREC, the NMART and EEI shall also meet to exercise the NRE Playbook at least once annually, prior to storm season, with timing coordinated to facilitate a report out at the Spring EEI CEO meeting. This exercise will provide an opportunity for sharing updates and any lessons learned, and any other pertinent business.

The NREC leadership has the responsibility to track these lessons learned and ensure that the lessons are addressed in a continuous improvement process.
V. National Response Event Communications

Timely, accurate and consistent communication throughout an NRE event is paramount. The process, roles and responsibilities designed to support the NRE effort ensure “one voice” communication with internal and external audiences.

A. NRE Communications Roles and Responsibilities

During a National Response Event (NRE) Edison Electric Institute (EEI) will serve as the investor-owned electric utility industry’s primary national information resource. EEI will serve as the industry liaison to EEI member company CEOs, senior government officials, and federal and state regulatory agencies. EEI will also provide communication support to the National Response Executive Committee (NREC).

In this role, EEI will provide a broad, national perspective on the event through media and public relations activities and industry-wide communication and coordination to relevant stakeholders.

Similar to EEI’s communication protocols during major storms, EEI’s efforts during an NRE will not take the place of or interfere with individual utilities’ efforts to communicate company-specific information to national or local reporters, elected officials, regulators, customers, and other stakeholders.

The following matrix outlines the communication steps and actions EEI will take before, during, and after a designated NRE.

B. Key NRE Stakeholders

**Internal Stakeholders**

EEI member company personnel

**External Stakeholders**

National media
National policymakers and elected officials
Federal Government partners
National organizations representing state officials (e.g., NCSL, NGA, NARUC, etc.)
Consumers
## C. Overall NRE Communications Process

### Prior to Event

Assuming there is advance notice of event, these activities will begin approximately 2-5 days before the beginning of the event. In the case of an event with no advance warning, these activities will commence as soon as an NRE is declared by the NREC (in this case, some Prior to Event actions will, by necessity, be combined with During Event actions).

<table>
<thead>
<tr>
<th>Communication Need</th>
<th>Audience</th>
<th>EEI Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prepare the press, policymakers and elected officials, customers, and other</td>
<td>National Media, Policymakers and Elected Officials, Federal Government</td>
<td>Distribute safety tips and restoration information and collaterals via social media channels and EEI web site.</td>
</tr>
<tr>
<td>stakeholders for a severe outage event.</td>
<td>Partners, Consumers</td>
<td><strong>Online resources</strong> include: tips on how to prepare for power outages, an emergency outage kit, and safety tips for various types of outages scenarios including earthquakes, flash floods, hurricanes, tornadoes, wildfires, and winter storms. Additionally, EEI has resources information on cybersecurity available, as need.</td>
</tr>
<tr>
<td>Focus on preparation and safety (for customers and crews), reinforce value of</td>
<td></td>
<td></td>
</tr>
<tr>
<td>electricity, and the commitment of industry to restoring power safely and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>efficiently.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Explain mutual assistance and power restoration process to the press,</td>
<td>National Media, Policymakers and Elected Officials, Federal Government</td>
<td>Distribute the background information on the industry mutual assistance program through the EEI web site, social media, and through media relations activities (see below).</td>
</tr>
<tr>
<td>policymakers and elected officials, customers, and other stakeholders.</td>
<td>Partners, Consumers</td>
<td></td>
</tr>
<tr>
<td>Address undergrounding issues, as needed.</td>
<td></td>
<td>Provide the press, policymakers and elected officials, and other stakeholders with information on issues related to undergrounding including the EEI report, Out of Sight, Out of Mind 2012.</td>
</tr>
<tr>
<td>Update member companies with event information.</td>
<td>EEI Members</td>
<td>Recirculate EEI materials and lists of additional resources to EEI member companies.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Provide member companies with pre-event talking points, template press releases, social media materials, and collaterals.</td>
</tr>
<tr>
<td>Conduct media relations outreach and education.</td>
<td>National Media</td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td></td>
</tr>
<tr>
<td>Provide EEI staff contact information to member companies. Set up daily “one voice” conference call with affected company communicators.</td>
<td>Provide pre-event briefings/updates and resources to the press explaining the how companies prepare for major outage events, the restoration process, and the industry's mutual assistance procedures. Make EEI leadership available to the press, as appropriate. Support company media relation efforts, as appropriate. Provide EEI staff contact information to press.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Activate EEI Storm Center.</th>
<th>Consumers EEI Members National Media Policymakers and Elected Officials Federal Government Partners</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace EEI’s home page with the EEI Storm Center/NRE Center. Visitors to <a href="http://www.eei.org">www.eei.org</a> will immediately see and have easy access to all of EEI storm/NRE resources.</td>
<td></td>
</tr>
<tr>
<td>Communication Need</td>
<td>Audience</td>
</tr>
<tr>
<td>-----------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Staff EEI Command Center.</td>
<td>EEI Members</td>
</tr>
<tr>
<td>Provide industry-wide information on event to media and member companies.</td>
<td>National Media, EEI Members, Policymakers and Elected Officials, Federal Government Partners</td>
</tr>
<tr>
<td>Serve as information clearinghouse on event.</td>
<td>EEI Members, Policymakers and Elected Officials, Federal Government Partners</td>
</tr>
<tr>
<td>Engage the public, the press, stakeholders including Federal agencies, groups representing state and local officials, Congress, Wall Street.</td>
<td>National Media, EEI Members, Policymakers and Elected Officials, Federal Government Partners, Consumers</td>
</tr>
<tr>
<td>Provide communication support to National Response Executive Committee</td>
<td>EEI Members, National Media, Policymakers and Elected Officials, Federal</td>
</tr>
</tbody>
</table>
## Post Event

<table>
<thead>
<tr>
<th>Communication Need</th>
<th>EEI Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Provide after action information.</td>
<td>Reinforce post-outage safety messages through web site and social media. Reinforce messages on how restoration process works, lessons learned to the press. Distribute information on industry system hardening and resiliency measures, as appropriate. Conduct post-event press briefing, as appropriate.</td>
</tr>
<tr>
<td>Report on final cumulative outage and response information.</td>
<td>Provide members with final outage matrix, put into historical context, if necessary.</td>
</tr>
<tr>
<td>Support members for post event regulatory hearings/proceedings.</td>
<td>Develop materials/talking points to help companies, as requested by companies.</td>
</tr>
<tr>
<td>Provide public/media relations support for members.</td>
<td>Provide media relations support (op-eds, letters to the editor, local/regional media outreach, etc.) in support of individual companies, as requested by companies. Capture and compile human interest, success stories, social media, press clips to share with members and external stakeholders. Conduct post-event quantitative and qualitative public opinion research, if requested by member companies. Run “thank you” advertising, as appropriate, to highlight the extent of the restoration effort, the role of mutual assistance, and the overall value of electricity, if requested by companies.</td>
</tr>
</tbody>
</table>
D. NRE Key Message Development and Approval Process

“Canned” messages for the NRE are listed below. The approval process for external messaging/press releases that contain NRE-specific message will follow the procedure below. EEI’s standard message approval process will apply to communications that do not specifically address the NRE or NREC actions. Draft media documents are vetted by the EEI Crisis Support Team’s Communications Lead.

1. Drafts are sent to subject-matter expert from legislative/policy/legal/operations as appropriate
2. Drafts are vetted by NREC Chair
3. Drafts are reviewed by EEI Crisis Support Team’s Communications Officer, Legal Officer, and Operations Officer.
4. Materials are sent to EEI’s Crisis Support Team’s Management Officer for final approval.
E. Checklists and Templates

Member company contacts are stored in Netforum in the “Senior Communication Executives” list. This list will be used for communicating directly with companies during an NRE.

Attached Checklists and Templates (see Appendix I)
Checklist: How to Activate the Storm Center
Checklist: Reporter’s List Guide
Template: Be Prepared, Be Safe Generic Preparedness Message
Template: News Clips and Social Media Summary (Sample from Sandy – not included, see Workroom)
Template: NRE Industry Communicators Conf. Call Agenda
Template: NRE Talking Points-During-Event
Template: NRE Talking Points-Pre-Event
Template: Opt In Email Request for External Stakeholders
Template: Outage Matrix
Template: Outage Overview
Template: Press Release NRE Activated
Template: Press Release Pre-Storm
Template: Press-Media Advisory NRE Press Call
Template: Scheduled Tweets
F. Canned Messages

Why has the industry not moved to a national response for this event?

The investor-owned electric utility industry defines a National Response Event (NRE) as a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). It’s important to understand an NRE designation is reserved only for the most significant events, such as a major storm, earthquake, an act of war, or other occurrence that results in widespread power outages.

Based on [weather forecasts/projections], this event does not appear to warrant a national response at this time. However, the industry’s regionally based mutual assistance program [is/will be activated] to support companies in [region] that need restoration resources. The industry and individual companies continue to closely monitor this event, and thanks to enhancements made after Superstorm Sandy, we can quickly scale the restoration effort to a national level if necessary.

[Northeast specific if appropriate] In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group (NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven. This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increases the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

Why does the industry not pre-deploy all resources based on a forecast?

Restoring power after a major incident is a complex task that must be completed as safely and efficiently as possible. A speedy restoration process requires significant logistical expertise, along with skilled workers and specialized equipment. Electric utilities begin their preparation for weather-related events long before an event actually occurs, with organization-wide plans and drills that involve virtually all employees. When a major storm or natural disaster is expected, electric utilities begin their standard preparations to organize restoration workers, trucks, and equipment. Mutual assistance is an essential part of the electric utility industry’s service restoration process and contingency planning. Electric utilities impacted by a major outage event are able to increase the size of their workforce by “borrowing” restoration workers from other utilities through the mutual assistance program.

An important part of these preparations is balancing the pre-deployment of resources with factors such as the weather forecast, damage potential, travel conditions, resource availability, and actual requests for assistance by utility companies. Individual companies have detailed restoration plans that address how they will restore service after major outages [direct to individual companies for specifics] that take into account the resources they have on hand, the potential threat, and the need for additional resources through the mutual assistance program. Because storms/events cannot be perfectly forecast, it isn’t prudent to call up all resources far in advance of an event. However, our regionally based mutual assistance program [is/will be activated if conditions warrant] to provide restoration support to utilities, and thanks to enhancements made after Superstorm Sandy, we can quickly scale the restoration effort to a national level if necessary.

Additional Reasons:

- Early pre-deployment could cause resources to be misdirected if the event forecast changes/event isn’t as serious as forecast
- Significant expenses may be incurred if resources are not needed (travel, lodging, logistics).
- Resources depending on the event/storm track may be needed in other areas first. Because companies have a duty to restore their “native” customers first, it is not possible to move resources until the event/storm track is clearer.
- [Northeast specific] In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group (NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven. This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increases the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

How are union issues being addressed? Are non-union crews being turned away?

[Local facts if known] In the case of significant outage events, electric utilities request and accept assistance from any and all qualified workers. The reports of non-union crews being turned away during Sandy were found to be untrue. Utilities in the affected areas and union representatives welcomed assistance regardless of their union status. [Redirect to companies and union representatives if necessary.]

Issues with Crossing State Lines/Crews Being Blocked from Moving

A timely restoration effort requires a smooth transition of resources from other regions into the affected area, regardless of the state boundary. Utility service territories often extend beyond state boundaries and restoration work often involves multiple jurisdictions. Having flexibility to move resources to the outage location is the key to successfully completing a restoration. The electric utility industry’s mutual assistance program ensures that all available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe and efficient manner.

The industry’s national response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving/on the road], and limiting utilities’ ability to move restoration resources in the most efficient manner undermines this process. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].

Workforce Issues: Will the enhancements made to the industry’s mutual assistance program get more workers to the outage in [AREA]?

The investor-owned electric utility industry’s mutual assistance program now has the ability to coordinate the allocation of restoration workers on a regional and national scale, but it does not create a larger overall pool of qualified restoration workers. The industry is working on workforce development through the Center for Energy Workforce Development and with programs like Troops to Energy Jobs, but these efforts are designed to bring new workers into the industry over time.

The industry’s response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving in the region/on the road/already at work]. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].
Hardening and Restoration: Will the enhancements made to the industry’s mutual assistance program make the system stronger/prevent outages?

The electric utility industry’s mutual assistance program is not designed to directly address infrastructure needs. These decisions are made by utilities and regulatory bodies that determine the most cost-effective measures to strengthen the grid and make it more resilient.

Will the enhancements to the mutual assistance program make the lights come on faster?

Due to the inherently unpredictable nature of disasters, the mutual assistance program cannot reduce the damage that may occur from severe outage events. Enhancements made to the process do scale up the industry’s mutual assistance program to address national level outages and ensure that mutual assistance is safe and efficient.

Would undergrounding prevent outages?

The mutual assistance program is not designed to directly address infrastructure needs. However, it is important to remember that some measures of reliability indicate that underground electric infrastructure has only a slightly better reliability performance than overhead electric systems, while other measures show a higher reliability factor for underground facilities. One explanation may be that many underground facilities are fed by overhead facilities that can become disabled during storms.

Repairs to underground facility outages are often more complex and time consuming, and such facilities are more costly to upgrade and replace. And, as recent experiences with Superstorm Sandy demonstrate, underground facilities are very vulnerable to flooding and water damage. Undergrounding also brings significant costs. Industry data show that costs for underground transmission and distribution construction costs can be between five to 10 times greater than for overhead.

Mutual Assistance Program Overview

The Edison Electric Institute’s mutual assistance program is a voluntary partnership of investor-owned electric utilities across the country committed to helping restore power whenever and wherever assistance is needed. Created decades ago, the mutual assistance program provides a formal, yet flexible, process for utilities to request support from other utilities in parts of the country that have not been affected by major outage events. Municipal utilities and electric cooperatives also have their own mutual aid programs that provide restoration support to their participating utilities.

Mutual assistance is an essential part of the electric utility industry’s service restoration process and contingency planning. Electric utilities impacted by a major outage event are able to increase the size of their workforce by “borrowing” restoration workers from other utilities. When called upon, a utility will send skilled restoration workers—both utility employees and contractors—along with specialized equipment to help with the restoration efforts of a fellow utility.

Partnerships in the mutual assistance program are based upon voluntary agreements among electric utilities within the same region. Most of these agreements are managed by seven Regional Mutual Assistance Groups (RMAGs) throughout the country. When a participating utility determines that it needs restoration assistance, it initiates a request through an RMAG. (Utilities in the western states coordinate responses directly with each other, rather than through an RMAG.)

RMAGs facilitate the process of identifying available restoration workers and help utilities coordinate the logistics and personnel involved in restoration efforts. For example, RMAGs can help utilities locate
specialized skill sets, equipment, or materials, and can assist in identifying other types of resources that may be needed, including line workers, tree trimmers, damage assessors, and even call center support.

**What enhancements were made to the mutual assistance program following Superstorm Sandy?**

The investor-owned electric utility industry has developed a new framework to institutionalize the lessons learned and best practices from Sandy in order to optimize restoration efforts following events that impact a significant population or several regions across the U.S. and require resources from multiple Regional Mutual Assistance Groups (RMAGs). In the case of significant outage events, where an industry-wide response is needed, all available industry emergency restoration resources (including contractors) will be pooled and allocated to participating utilities to safely and efficiently meet restoration needs.

A committee of senior-level member company utility executives from all regions of the country governs this allocation process, with members drawn from utilities in each of the seven RMAGs. RMAGs will continue to facilitate the process of identifying available restoration workers and help utilities coordinate the logistics and personnel involved in restoration efforts.

One of the important lessons learned following Superstorm Sandy was that there were too many small RMAGs in the Northeast. In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group (NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven.

This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increase the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

The electric utility industry continues to collaborate and work with the federal government and the states to enhance and formalize industry-government partnerships developed during Superstorm Sandy. These efforts include:

- Improving communication and coordination by embedding senior industry officials with government response teams at the U.S. Department of Energy and coordinating with the Federal Emergency Management Agency.
- Streamlining transportation by developing information resources and tools to expedite the movement of resources across state lines in partnership with the U.S. Department of Transportation and state transportation agencies. Additionally, we have negotiated a new procedure for U.S. and Canadian border crossings with the Department of Homeland Security and the Canadian Border Services Agency to minimize delays and to ensure timely movement of mutual assistance crews across the international border.
- Engaging in an ongoing dialogue with the Department of Defense (DOD) to enhance logistical support, such as access to DOD property and facilities for pre-staging areas, exploring ways to enhance security and road access with the National Guard, and securing access to critical supplies and equipment from the Army Corps of Engineers.
How is the National Response Event Framework Different from the Current Mutual Assistance Program?

The current mutual assistance program works well for regional events, but was not designed to be scalable for national events. After Superstorm Sandy, a storm of unprecedented size and scope, the investor-owned electric utility industry enhanced its mutual assistance program to improve how it responds to a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and that requires resources from multiple RMAGs.

To meet the challenges of these major national events, a new National Response Event (NRE) framework was developed. When an NRE is activated, the investor-owned electric utility industry’s mutual assistance efforts will be scaled to the national level and coordinated so industry restoration resources are allocated in a singular and seamless fashion.

All available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe, efficient, and equitable manner. This process is overseen by a new National Response Executive Committee (NREC) comprised of senior-level member utility executives from all regions of the country.

During an NRE, the NREC will activate a National Mutual Assistance Resource Team (NMART) that will evaluate mutual assistance requests and assign available resources to affected utilities in coordination with the RMAGs. The Edison Electric Institute (EEI) will serve as the industry liaison to EEI member company CEOs, senior government officials, and federal and state regulatory agencies. EEI will also serve as the investor-owned electric utility industry’s primary national information resource providing a broad, national perspective on the event.

The NRE framework allows EEI member utilities to efficiently coordinate and scale their restoration resources to create an industry-wide national response effort while retaining the current, successful, and geographically based RMAG mutual assistance process for events that do not require a national response.

Specifically how does the mutual assistance program allocate response resources during a National Response Event?

The national allocation of response resources uses a formula that takes into account the proportion of customer outages and the proportion of trouble spots relative to all requesting utilities. Additional qualitative refinements to the allocation may also be made based on geography, travel routes, type of damage, and other factors that can affect restoration. After the allocation, resource matching to individual utilities is conducted through the Regional Mutual Assistance Groups (RMAGs) based on local requirement. Reallocation of resources is also built into the process so restoration workers and equipment can be effectively redeployed throughout an event. The process is designed to make an efficient and equitable allocation based on need.

What are the specific numbers?

[EEI will release national numbers based on publicly available information and information from the NREC/NMART.]
Appendix A: Conference Call Agendas

Initial NRE Conference Call

The initial NRE call will take place within 2 hours of the NRE activation and will be initiated by the NREC Chair or in his/her absence by the Vice Chair or the Second Vice Chair.

Initial NRE Conference Call Participants

The participants in the initial call will include at the minimum the individuals (or their designees) serving the following NRE roles:

- NREC Chair
- NREC Vice Chair
- NMART Co-Chairs
- EEI NRE Operations Officer, Operations Liaison, Communications Liaison

NREC Chair may invite other members of the NREC. The names and contact information for each of the roles is provided in the Appendix B of this playbook.

Initial NRE Conference Call Agenda

<table>
<thead>
<tr>
<th>Agenda Item</th>
<th>Responsible</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Roll call</td>
<td>NREC Chair</td>
</tr>
<tr>
<td>2. Review the reason for NRE activation and background</td>
<td>NREC Chair</td>
</tr>
<tr>
<td>3. Provide status of mutual assistance activity</td>
<td>NREC Chair</td>
</tr>
<tr>
<td></td>
<td>Weather forecast</td>
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<tr>
<td></td>
<td>Currently activated RMAGs</td>
</tr>
<tr>
<td></td>
<td>Status of existing mutual assistance requests and any allocations that have been made within the RMAGs</td>
</tr>
<tr>
<td></td>
<td>Cross-RMAG calls and assignments prior to NRE</td>
</tr>
<tr>
<td></td>
<td>Contractor engagement</td>
</tr>
<tr>
<td>4. Set the roster for NRE support in this event</td>
<td>NMART Co-Chairs</td>
</tr>
<tr>
<td></td>
<td>Determine availability of the key NRE team members to support this event</td>
</tr>
<tr>
<td></td>
<td>Set the roster for the NRE support based on availability</td>
</tr>
<tr>
<td></td>
<td>Agree on the date, roles and location (should be EEI HQ unless it is not accessible) for NRE co-location</td>
</tr>
<tr>
<td>4. Update the team on the EEI activity</td>
<td>EEI Operations Officer, Operations Liaison, Communications Liaison</td>
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<tr>
<td></td>
<td>Discuss any CEO calls that may have already taken place</td>
</tr>
<tr>
<td></td>
<td>Understand the overall communication strategy key EEI messages related to the event</td>
</tr>
<tr>
<td>5. Set the objectives for the next 24 hours (until the next call)</td>
<td>NREC Chair</td>
</tr>
<tr>
<td></td>
<td>Set the specific timeline for the initial allocation</td>
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<tr>
<td></td>
<td>Agree on the daily NRE conference call schedule</td>
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<tr>
<td>Agenda Item</td>
<td>Responsible</td>
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<td>-------------</td>
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</tr>
<tr>
<td>1. Roll call</td>
<td>NREC Chair</td>
</tr>
<tr>
<td>2. Provide an outage status and weather forecast update</td>
<td>NMART Co-Chairs</td>
</tr>
<tr>
<td>3. Review the current period allocations</td>
<td>NREC Chair</td>
</tr>
<tr>
<td>4. Discuss any unique issues (Chair’s discretion)</td>
<td>NREC Chair</td>
</tr>
</tbody>
</table>

**Initial NRE Conference Call Documentation**

The NREC Chair will designate someone on the call to capture the notes from the conference call.

**Daily NRE Conference Call**

The timing of the daily NRE conference call will be determined in the initial call and can be adjusted as necessary by the NREC Chair. The objective of this call is to discuss any potential issues related to resource allocation in preparation for the CEO conference calls. Typically, these calls will take place right before CEO calls, which start at 3:30pm every day.

**Daily NRE Conference Call Participants**

The participants in the initial call will include at the minimum the individuals (or their designees) serving the following NRE roles:

- NREC Chair
- NREC Vice Chair
- NREC Members
- NMART Co-Chairs
- EEI NRE Liaison

Names and contact information for each of these roles is provided in the Appendix B of this playbook.

**Daily NRE Conference Call Agenda**

<table>
<thead>
<tr>
<th>Agenda Item</th>
<th>Responsible</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Roll call</td>
<td>NREC Chair</td>
</tr>
<tr>
<td>2. Provide an outage status and weather forecast update</td>
<td>NMART Co-Chairs</td>
</tr>
<tr>
<td>3. Review the current period allocations</td>
<td>NREC Chair</td>
</tr>
<tr>
<td>4. Discuss any unique issues (Chair’s discretion)</td>
<td>NREC Chair</td>
</tr>
</tbody>
</table>
### Agenda Item

<table>
<thead>
<tr>
<th>Agenda Item</th>
<th>Responsible</th>
</tr>
</thead>
<tbody>
<tr>
<td>▪ Media issues</td>
<td></td>
</tr>
<tr>
<td>5. Prepare key talking points for the CEO calls</td>
<td>NMART Co-Chairs</td>
</tr>
<tr>
<td>▪ Confirm key statistics</td>
<td></td>
</tr>
<tr>
<td>6. Set the objectives for the next 24 hours (until the next call)</td>
<td>NREC Chair</td>
</tr>
<tr>
<td>7. Summarize the next steps</td>
<td>NREC Chair</td>
</tr>
</tbody>
</table>

**Daily NRE Conference Call Documentation**

The NREC Chair will designate someone on the call to capture the notes from the conference call.
PRE—ACTIVATION CALL
EEI CEO NREC PCRBC Call #0
3:30pm Eastern
(Impacted CEOs, PCRBC and NRE Chair (no government officials))
1-412-317-6060 (Ask for the EEI NRE call)

Call Purpose

- Gather information and input from CEOs from within the impacted areas
- Provide CEOs update on the NRE allocation process and share information communicated to or through the NREC
- Identify areas for potential federal government coordination or support

Agenda

1. Introduction & Roll Call (Tom Kuhn, or designee)
2. NREC Report (NREC Chair, or designee)
   a. Safety Message
   b. Weather Report
3. Requesting CEO(s) provide reason for NRE request
4. NREC Chair reviews criteria for NRE
5. RBC Co-Chairs provide counsel
6. Discussion and Decision
   a. Will NRE be triggered?
   b. Where will core team meet
7. Adjourn
EEI CEO NRE Call #1
3:30pm Eastern
(Impacted CEOs and NRE Team (no government officials))
1-412-317-6060 (Ask for the EEI NRE call)

Call Purpose

- Gather information and input from CEOs from within the impacted areas
- Provide CEOs update on the NRE allocation process and share information communicated to or through the NREC
- Identify areas for potential federal government coordination or support

Agenda

8. Introduction & Roll Call (Tom Kuhn, or designee)
9. NREC Report (NREC Chair, or designee)
   a. Safety Message
   b. Weather Report
10. CEO Input
11. Impacted Company CEOs, or designees
12. Areas of Needed Government Coordination
13. Adjourn
EEI CEO NRE Call #2

4:30pm Eastern
(All CEOs and NRE Team (no government officials))
412-717-9582 (Ask for the EEI NRE call)

Call Purpose

- Gather additional information and input from CEOs not operating within the impacted areas
- Provide all CEOs update on the NRE allocation process and share information communicated to or through the NREC
- Identify areas for potential federal government coordination or support

Agenda

14. Introduction & Roll Call (Tom Kuhn, or designee)
15. NREC Report (NREC Chair, or designee)
   a. Safety Message
   b. Weather Report
16. CEO Input
17. Impacted Company CEOs, or designee
18. Other CEOs, or designees
19. Areas of Needed Government Coordination
20. Adjourn
EEI CEO NRE Call #3
5:15pm Eastern
(All CEOs, NRE Team, Federal Government Officials)
412-717-9582 (Ask for the EEI NRE call)

Call Purpose
- Provide federal government partners information from within the impacted areas
- Provide federal government partners an update on the NRE allocation process and share information communicated to or through the NREC
- Discuss identified areas for potential federal government coordination or support

Agenda
1. Introduction & Roll Call (Tom Kuhn, or designee)
2. Federal Government Opening Remarks (Government / DOE Leadership)
3. NREC Report (NREC Chair, or designee)
   a. Safety Message
   b. Weather Report
4. CEO Input (CEOs, or designees)
5. Industry / Federal Government Discussion on Areas of Needed Government Coordination
6. Adjourn
NMART Call Agenda

In order to ensure efficiency of the discussion during the NMART call, the following standing agenda will be used.

**NMART Conference Call Agenda**

<table>
<thead>
<tr>
<th>Agenda Item</th>
<th>Responsible</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Roll call</td>
<td>NMART Co-Chair</td>
</tr>
<tr>
<td>2. Confirm in-person participation and location</td>
<td>NMART Co-Chair</td>
</tr>
<tr>
<td>- If either the chair or vice chair do not have the capacity, for any</td>
<td></td>
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<tr>
<td>reason, to organize the event and travel to Washington (or another</td>
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<tr>
<td>designated location, appoint designees who will serve in those roles</td>
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</tr>
<tr>
<td>for this event</td>
<td></td>
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<tr>
<td>3. Weather report/system status (if needed)</td>
<td>NMART Vice Chair</td>
</tr>
<tr>
<td>4. Review NRE Template (if not available or incomplete instruct the team</td>
<td>NMART Co-Chair</td>
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<tr>
<td>to gather the information)</td>
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<tr>
<td>- Review template for mistakes, omissions, or inconsistencies,</td>
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<tr>
<td>including all requested and available resources</td>
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<tr>
<td>- Verify that all requests have been reported through the home RMAG</td>
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<tr>
<td>- Utilize the allocation model to determine the formulaic allocation</td>
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<tr>
<td>- Refine the allocations based on other factors and capture the</td>
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<tr>
<td>discussion around any adjustments to the initial allocations</td>
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</tr>
<tr>
<td>5. Discuss non-line or line clearance (tree trimming) resource requests</td>
<td>NMART Co-Chair</td>
</tr>
<tr>
<td>6. Discuss any unique issues (Chair’s discretion)</td>
<td>NMART Co-Chair</td>
</tr>
<tr>
<td>- Significant safety issues (public and restoration worker)</td>
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<tr>
<td>- Peer Emergency Management community issues</td>
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<tr>
<td>- Media issues</td>
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<tr>
<td>7. Schedule the next call</td>
<td>NMART Co-Chair</td>
</tr>
</tbody>
</table>

**Post NMART Conference Call Documentation**

After each conference call, NMART members will capture the key decisions and outstanding items. The level of documentation will provide enough specificity to allow for after-action review and lessons learned effort. Following are two key activities:

1. Prepare Call Documentation (Secretary)
   - Completed allocation template
     - Resources already secured
     - Total resources requested
     - Total resources available
     - All other allocation criteria
     - Allocation (by utility)
   - Criteria used for Allocation
   - Outstanding issues
   - Next call time and date
2. Disseminate the documentation (Secretary)
   - All NMART team members (for distribution to all RMAG Executive Committee members)
   - EEI Liaison
   - NREC Chair
Appendix B: Membership and Contact Lists

- National Response Executive Committee (NREC)
- National Mutual Assistance Resource Allocation Tool (NMART)
- “Home” RMAG List
## National Response Executive Committee (NREC)

<table>
<thead>
<tr>
<th>Role</th>
<th>Name</th>
<th>Other Names</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Chair</strong></td>
<td>Tom Kirkpatrick</td>
<td></td>
</tr>
<tr>
<td><strong>1st Vice-Chair</strong></td>
<td>Bill Quinlan</td>
<td></td>
</tr>
<tr>
<td><strong>2nd Vice-Chair</strong></td>
<td>Keith Hull</td>
<td></td>
</tr>
<tr>
<td><strong>EEI STAFF</strong></td>
<td>Paul Frey</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Gail Royster</td>
<td></td>
</tr>
</tbody>
</table>

### Great Lakes Mutual Assistance Group (GL MAG) – Great Lakes MA
- **Primary:** Tom Kirkpatrick
- **1st Alternate:** Steve Straub
- **2nd Alternate:** Daniel Malone

### Midwest Mutual Assistance Group (MMAG) – Midwest MA
- **Primary:** Melody Birmingham-Byrd
- **1st Alternate:** James Conway
- **2nd Alternate:** Bruce Akin

### North Atlantic Mutual Assistance Group (NAMAG) – North Atlantic MA
- **Primary:** Bill Quinlan
- **1st Alternate:** Dave Bonenberger
- **2nd Alternate:** John Donlevy

### Southeastern Electric Exchange (SEE) – Southeastern Electric Exchange
- **Primary:** Manny Miranda
- **1st Alternate:** Greg Grillo
- **2nd Alternate:** Danny Glover

### Texas Mutual Assistance Group (TX MAG) – Texas MA
- **Primary:** Keith Hull
- **1st Alternate:** David Baker
- **2nd Alternate:** Mike Mathews

### Western Region Mutual Assistance Group (WR MAG) – Western Region MA
- **Primary:** Barry Anderson
- **1st Alternate:** Doug Butler
- **2nd Alternate:** Dana Kracke

### Wisconsin Utilities Association Mutual Assistance Group (WUA) – Wisconsin Utilities Assoc.
- **Primary:** Vern Gebhart

### AT-Large
- **Primary:** Carlos Torres
- **Primary:** Mike Sullivan

*August 2014*
1. At the time an NRE is declared, please make yourself available for the Chair and Vice Chair.

2. Please ensure the companies you represent in the NRE process understand the gravity of the situation and are responding appropriately.

3. Maintain communications with your CEO and others within your company keeping them aware of the situation, and providing any updates that would be beneficial.

4. Provide updates as needed to those companies you represent through your NRE team.

5. Provide feedback if there are process issues or third party concerns to the Chair and Vice Chair.

6. Support the NRE process with those whom may question as we work through the event.

7. If questions arise, please work through the NREC group to develop responses if unknown.

8. Support your peers who are battling the event.

9. Support the NMART and EEI Communication teams and their processes.

10. Remember to be engaged, you could be the one in the barrel the next time.
## National Mutual Assistance Resource Team (NMART)

**Executive Committee 2014**

<table>
<thead>
<tr>
<th>CO-CHAIRS</th>
<th>Aaron Strickland</th>
</tr>
</thead>
<tbody>
<tr>
<td>VICE-CHAIR</td>
<td>Rachel Sherrill</td>
</tr>
<tr>
<td>SECRETARY</td>
<td>Marty Wright</td>
</tr>
<tr>
<td>SECRETARY IN WAITING</td>
<td>Mike Zapponi</td>
</tr>
<tr>
<td>EII STAFF</td>
<td>Gail Royter</td>
</tr>
<tr>
<td></td>
<td>Paul Frey</td>
</tr>
</tbody>
</table>

**Great Lakes Mutual Assistance Group (GLMAG) – Great Lakes MA**

- **PRIMARY** – Marty Zearbaugh
- **SECONDARY** – Brian Gatewood

**Midwest Mutual Assistance Group (MMAG) – Midwest MA**

- **PRIMARY** – Bryan Nowlin
- **SECONDARY** – Carol Baxter

**North Atlantic Mutual Assistance Group (NAMAG) – North Atlantic MA**

- **PRIMARY** – Chuck Anna
- **SECONDARY** – Tom Murphy

**Southeastern Electric Exchange (SEE) – Southeastern Electric Exchange**

- **AT LARGE** – Jim Collins
- **AT LARGE** – Scott Smith
- **PRIMARY** – Michael Fricker
- **SECONDARY** – “Vacant”

**Texas Mutual Assistance Group (TXMAG) – Texas MA**

- **PRIMARY** – Mike Carter
- **SECONDARY** – Jeffrey Dossey

**Western Region Mutual Assistance Group (WRMAG) – Western Region MA**

- **PRIMARY** – Don Daigle
- **SECONDARY** – Gary Nieborsky

**Wisconsin Utilities Association Mutual Assistance Group (WUAMAG) – Wisconsin Utilities Assoc.**

- **PRIMARY** – Don LuMaye
- **SECONDARY** – John Nesbitt

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August 2014
EEI T&D Officers with Operations Responsibilities

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<tr>
<td>Kuhn, Thomas R.</td>
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<tr>
<td>Owens, David K.</td>
<td>Executive Vice President, Business Operations</td>
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<tr>
<td>Wolff, Brian L.</td>
<td>Executive Vice President, Public Policy &amp; External Affairs</td>
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<td>Comer, Edward H.</td>
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<td>Easton, John J.</td>
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<td>Fama, James P.</td>
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EEI Energy Delivery Group

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<tr>
<td>Eisenbrey, Chris</td>
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Communications

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CEO Policy Committee on Reliability and Business Continuity
August 2014

Rigby, Joe (co-chair)  Pepco Holdings, Inc.
Spence, William (co-chair)  PPL Corp.
Torgerson, Jim (co-chair)  UIL Holdings Corp.

Blue, Bob  Dominion
Borkowski, Maureen  Ameren Services
Bridge, Tracy  CenterPoint Energy
Crane, Christopher  Exelon Corp.
Donleavy, John  National Grid
Fehrman, William  MidAmerican
Fowke III, Benjamin  Xcel Energy
Greene, Kim  Southern Company
Greer, Jim  Oncor
Harris, Kimberly  Puget Sound Energy
Hutchens, David  UniSource
Jones, Charles  FirstEnergy
Kampling, Patricia  Alliant Energy
Koonce, Paul  Dominion
Lau, Constance  Hawaiian Electric Industries Inc.
Litzinger, Ron  Southern California Edison
McAvoy, John  Consolidated Edison
Morris, Scott  Avista Corp.
Olivier, Leon  Northeast Utilities
Piro, James  Portland General Electric
Powers, Bob  AEP
Procario, John  American Transmission Company
Ramil, John  TECO Energy
Riazi, Richard  Duquesne Light
Ruelle, Mark  Westar Energy
Schiavoni, Mark  Arizona Public Service
Schrock, Charles  Integrys
Sliagy, Eric  Florida Power & Light
Stanley, Jim  NIPSCO
Vincent-Collawn, Pat  PNM Resources
Walker, Kevin  Iberdrola USA
Welch, Joseph  ITC Holdings Corp.
West, Rod  Entergy
Williams, Geisha  Pacific Gas & Electric
Yates, Lloyd  Duke Energy
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Appendix C: Web Content/Document Repository

NRE Electronic Workroom

EEI's Issue Workrooms provide members an online forum to facilitate policy development, information exchange and networking. Members communicate and share ideas, participate in discussion forums, send email blasts, create file libraries, organize conference calls and keep track of important dates and upcoming events.

EEI utilizes the NRE Workroom as both a document and NMART tool repository as well as a communications means. EEI is able to limit access to documents and tools to those who need access; provide simultaneous access to documents and tools; and quickly change access as needs arise through the use of Groupsite.com.

To access the NRE Workroom, set your browser to “groupsite.com” and login. If you do not have access, contact your EEI representative.

Following is the opening page to the NRE Workroom.
Documentation Retention

EEI General Policy is listed below. More detail is available if needed.

---

**Edison Electric Institute**

**Records Retention Schedule**

**August 2013**

**General Guidance**

1. Most files, publications and materials only need to be kept while a matter is active.

2. Member information, financial information, contracts, purchasing and other business records, personnel files, meeting attendance and payment records are the responsibility of EEI's administrative groups. Legal and regulatory filings, testimony and EEI studies, reports and publications are the responsibility of each individual business group, governmental affairs and supporting groups.

3. Detailed guidance is included. It applies to both hard copy and electronic files.

4. If you have questions, please seek guidance from your supervisor or contact Ed Comer, x5615

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These are the general guidelines. Specific guidelines for an NRE need to be developed.
Appendix D: Key Maps

EEI U.S. Member Company Service Territory (March 2014)
Mutual Assistance Agreement - as of 5/2014

Signed

AES Corporation
Dayton Power and Light
Indiana Power & Light Company

ALLETE
Minnesota Power
Superior Water, Light and Power Company

Alliant Energy Corporation
Interstate Power and Light Company
Wisconsin Power and Light Company

Ameren Corporation
Ameren Illinois
Ameren Missouri

American Electric Power, Inc.
APR Ohio
APR Texas
Appalachian Power
Indiana Michigan Power
Kentucky Power
Public Service Company of Oklahoma
Southwestern Electric Power Company

American Transmission Company
Angus Corporation
Avista Utilities

Black Hills Corporation
Black Hills Energy
Black Hills Power
Cheyenne Light, Fuel & Power Company

CenterPoint Energy, Inc.

CH Energy Group, Inc.
Central Hudson Gas & Electric Corporation

Chesapeake Utilities Company
Florida Public Utilities Company

Cleco Corporation
Cleco Power LLC

CMS Energy Corporation
Consumers Energy

Consolidated Edison, Inc.
Consolidated Edison Company of New York, Inc.
Orange and Rockland Utilities, Inc.
Pike County Light & Power Company
Roseland Electric Company

Dominion

DTE Energy Company
Detroit Edison

Duke Energy
Duquesne Light Holdings, Inc.

Duquesne Light Company

Edison International
Southern California Edison Company

Empire District Electric Company, The
Energy Future Holdings

Energy Corporation

EnergySource

FirstEnergy Corp.
The Cleveland Electric Illuminating Company
Jersey Central Power & Light Company
Metropolitan Edison Company
Monongahela Power

Ohio Edison Company
Pennsylvania Electric Company
Pennsylvania Power Company

Profit Energy

PPL Corporation
Kentucky Utilities Company
Louisville Gas and Electric Company

Public Service Enterprise Group, Inc.
Public Service Electric and Gas Company

Public Service of Wisconsin

Upper Peninsula Power Company
Wisconsin Public Service Corporation

ITC Holdings Corp.

ITC Great Plains
ITC Midwest
ITC Transmission

Michigan Electric Transmission Company, LLC (MTEC)

MGE Energy, Inc.

MidAmerican Energy Holdings Company
MidAmerican Energy Company

Pacific Gas

Rocky Mountain Power

National Grid

NextEra Energy, Inc.

NESource Inc.

Northeast Utilities

The Connecticut Light and Power Company

NStar

Public Service Company of New Hampshire

Western Massachusetts Electric Company

Northwestern Energy

NV Energy

OGE Energy Corporation

OGE Electric Services

Otter Tail Corporation

Otter Tail Power Company

Pepco Holdings, Inc.

Atlantic City Electric
Delmarva Power

Pepco

PGE Corporation

Pacific Gas & Electric Company

Pinnacle West Capital Corporation

Arizona Public Service Company

PSM Resources, Inc.

PJM

Tucson Electric Power Company

Portland General Electric

PPL Corporation

Kentucky Utilities Company

Louisville Gas and Electric Company

Public Service Enterprise Group, Inc.

Public Service Electric and Gas Company

PSE&G

Puget Energy, Inc.

Puget Sound Energy

SCANA Corporation

South Carolina Electric & Gas Company

Southern Company

Alabama Power Company

Georgia Power Company

Gulf Power Company

Mississippi Power Company

TECO Energy, Inc.

 Tampa Electric Company

UGI Corporation

UGI Utilities, Inc.
### Mutual Assistance Agreement - as of 5/2014

**Not Signed**

- Alaska Electric Light and Power Company
- El Paso Electric Company
- Emera
- Range Hydro Electric Company
- Maine Public Service Company
- Enel Green Power North America
- Hawaiian Electric Industries
- Hawaii Electric Light Company
- Maui Electric Company, L.L.C.
- IDACORP, Inc.
- Idaho Power Company
- MDU Resources Group, Inc.
- Montana-Dakota-Helton Co.
- ML Cannel Public Utility Company
- UNS Energy Corporation
- Tucson Electric Power Company
- Intermountain Energy Services
- Vermont Electric Power Company

**On Mutual Assistance signing list as Previous Company name**

- Allegheny Energy Inc (merged with FirstEnergy)
  - Allegheny Power
- *Central Vermont Public Service acquired by Gaz Metro and combined with and called Green Mountain Power
- *Energie (acquired by Dake)
- LG&E (PPL)
- FPL Group (acquired by NextEra)
- KeySpan Corp (National Grid)
- Progress Energy Inc (Duke)
EEI Facility and NRE Rooms

EEI Headquarters is Located at 701 Pennsylvania Ave, NW, Washington, DC 20004
The General Number is 202-508-5000

NREC will convene in the Edison Conference Room B
NMART will convene in the Edison Conference Room A
Menlo Park will be a breakout room
President’s Conference Room is for use by EEI and will be used to host the CEO calls
NRE Alternate Facility Ashburn, VA

This facility which houses EEI’s offsite servers, has a 500 square foot conference room outfitted with tables, 12 chairs, an air printer, multiple big screen televisions, white boards, and one land line conference capable phone.
NRE Alternate Facility NorthWest

PacifiCorp Learning Center
Lloyd Center Mall, Suite 2265, 3rd Floor – East End
825 NE Multnomah Street
Portland, OR 97232

Welcome to the Lloyd Learning Center
Lloyd Center Mall
Suite 2265, 3rd floor – East End

Any reservations must go through PacifiCorp Learning. Send requests to PacifiCorpLearning@PacifiCorp.com.
These rooms have a ceiling-mounted projector and projection screen.

Any reservations must go through a scheduler who currently can reserve LCT 720 or Facilities (email FacilitiesPlanning). These rooms have a ceiling-mounted projector and projection screen.

Reserved through Outlook – open the room’s calendar and create an appointment or meeting request. Include contact information.

Kitchen, coffee and break area for all attendees.

Rules
You will need a PacifiCorp badge to gain access to the Lloyd Learning Center. All non-badged visitors must be escorted at all times.

The meeting organizer is responsible for any catering needs.

The meeting organizer is responsible for cleaning up the room after it has been used and returning the tables and chairs to the default configuration.

825 NE Multnomah St, Portland, Multnomah, OR
825 NE Multnomah St
Explore this area

825 NE Multnomah St
Explore this area
NRE Alternate Facility SouthWest

Oncor System Emergency Center
Woodall Rodgers Building, 2nd Floor
1616 Woodall Rodgers FWY
Dallas, Tx 75202
Regional Mutual Assistance Groups – Map and NREC Members

Below is an interactive link to the Regional Mutual Assistance Groups identifying each region along with each member company participating within that region. The link will require you to login to the NRE Workroom.

RMAG 03 2014 CN.pdf
Appendix E: EEI Mutual Assistance Agreement

Edison Electric Institute
Mutual Assistance Agreement

Edison Electric Institute ("EEI") member companies have established and implemented an effective system whereby member companies may receive and provide assistance in the form of personnel and equipment to aid in restoring and/or maintaining electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable ("Emergency Assistance"). This Mutual Assistance Agreement sets forth the terms and conditions to which the undersigned EEI member company ("Participating Company") agrees to be bound on all occasions that it requests and receives ("Requesting Company") or provides ("Responding Company") Emergency Assistance from or to another Participating Company who has also signed the EEI Mutual Assistance Agreement; however, that if a Requesting Company and one or more Responding Companies are parties to another mutual assistance agreement at the time of the Emergency Assistance is requested, such other mutual assistance agreement shall govern the Emergency Assistance among those Participating Companies.

In consideration of the foregoing, the Participating Company hereby agrees as follows:

(1) When providing Emergency Assistance to or receiving Emergency Assistance from another Participating Company, the Participating Company will adhere to the written principles Suggested Governing Principles Covering Emergency Assistance Arrangements Between Edison Electric Institute Member Companies adopted in September 2005 ("EEI Governing Principles"), that are in effect as of the date of a specific request for Emergency Assistance, unless otherwise agreed to in writing by each Participating Company.

(2) When a National Response Event ("NRE") is activated due to a natural or man-made event that is forecast to or causes widespread power outages, impacting a significant population or several regions across the United States, that requires resources from multiple Regional Mutual Assistance Group(s) ("RMAG" or "RMAGs"), the Participating Companies will operate in accordance with the current National Response Event Structure and Principles Covering Emergency Assistance Arrangement between Edison Electric Institute Member Companies.
(3) In recognition of the confidential nature of the number of resources and allocation of those resources in an NRE event as well as the methodology used to allocate those resources, the Participating Companies agree to the confidentiality provisions set forth in the National Response Event Structure and Principles Covering Emergency Assistance Arrangements between Edison Electric Institute Member Companies.

(4) With respect to each Emergency Assistance event, Requesting Companies agree that they will reimburse Responding Companies for all costs and expenses incurred by Responding Companies in providing Emergency Assistance as provided under the EEI Principles, unless otherwise agreed to in writing by each Participating Company; provided, however, that Responding Companies must maintain auditable records in a manner consistent with the EEI Principles.

(5) During each Emergency Assistance event, the conduct of the Requesting Companies and the Responding Companies shall be subject to the liability and indemnification provisions set forth in the EEI Principles.

(6) A Participating Company may withdraw from this Agreement at any time. In such an event, the company should provide written notice to Vice President of Energy Delivery or his/her designee who shall maintain a list of each Mutual Assistance Agreement Participating Company Signatory which shall be posted in the EEI NRE Workroom http://nre.groupsite.com/main/summary. A Participating Company may request a copy of the signed Mutual Assistance Agreement of another Participating Company prior to providing or receiving Emergency Assistance.

__________________________________
Company Name

__________________________________
Signature

Officer Name:
Title:
Date:
SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company’s needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company’s location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company’s employees. It is understood and agreed that if; in the Responding Company’s judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company’s crews shall be given by Requesting Company to Responding Company’s supervisor(s); or, when Responding Company’s crews are to work in widely separate areas, to such of Responding Company’s foremen as may be designated for the purpose by Responding Company’s supervisor(s).
5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the requesting company.

6. Responding Company’s safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company’s switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

   a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

   b. Employee travel and living expenses (meals, lodging and reasonable incidentals).

   c. Replacement cost of materials and supplies expended or furnished.

   d. Repair or replacement cost of equipment damaged or lost.

   e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.

   f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or
injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13. Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contractors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Last update September 2005
- Section 11 and 12 updated
National Response Event Structure and Principles Covering Emergency Assistance Arrangements between Edison Electric Institute Member Companies

This document sets forth the structure and principles that Participating Companies agree to follow when engaged in Emergency Assistance activities during a National Response Event (“NRE”). An NRE is a natural or man-made event that is forecast to or causes widespread power outages, impacting a significant population or several regions across the United States that requires resources from multiple Regional Mutual Assistance Group(s) (“RMAG” or “RMAGs”). When an NRE is activated, all available emergency restoration resources (including contractors) will be pooled and allocated to Participating Companies in a safe, efficient, transparent and equitable manner.

Structure:

National Response Executive Committee ("NREC"). The NREC is responsible to the Edison Electric Institute ("EEI") Board of Directors. The NREC will provide executive leadership to develop procedures and processes covering Emergency Assistance arrangements between Participating Companies to respond to an NRE. The NREC will also review and validate a request to declare an NRE, and resolve any issues stemming from the resource allocation process.

The EEI Board of Directors will designate one Participating Company executive from each RMAG to serve as primary members of the NREC, as well as two additional executives from each RMAG (except for the Wisconsin RMAG, which shall have one primary member) to serve as first and second alternates, respectively. The EEI Board of Directors shall also, at their discretion, designate up to two additional ‘at large’ executives to serve as primary members of the NREC. Members of the NREC shall be executive level, have operations and emergency assistance experience and possess the ability to communicate at all levels of management. No one Participating Company, or parent thereof, may have multiple members on the NREC.

The leadership of the NREC shall consist of a Chair, a Vice Chair, and a Second Vice Chair. The NREC shall annually elect a Second Vice Chair from its membership at its first meeting of each year. At that time, the Vice Chair will assume the role of Chair, the Second Vice Chair will assume the role of Vice Chair, and the newly elected Second Vice Chair shall become Second Vice Chair. All leadership roles will last one year. The three officers will rotate on a yearly cycle. Other NREC members will rotate on a three year cycle and be replaced sequentially; with the primary member rolling off, the first alternate becoming primary, the second alternate becoming the first alternate and the new second alternates designated by the EEI Board of Directors. The two ‘at large’ NREC members shall serve one-year terms and be replaced on an annual basis.

National Mutual Assistance Resource Team ("NMART"). During an NRE, the NMART is responsible for collecting information regarding the scope of actual or forecasted damage, determining available and requested resources and allocating the available resources in a safe, efficient, transparent and equitable manner as prescribed by its policies and procedures.
The NMART consists of the officers of the EEI Mutual Assistance/Emergency Preparedness Committee ("EEI MA/EP") and one representative from each RMAG. The EEI MA/EP Chairs and Vice Chair and will serve as the NMART Chairs and Vice Chair, respectively.

Edison Electric Institute. EEI serves as the industry liaison to EEI Member Company Chief Executive Officers ("CEOs"), senior government officials, federal agencies, and national organizations representing state and local interests. At the request of an EEI Member, EEI may also serve as an industry liaison to state regulatory agencies. During an NRE, EEI convenes periodic conference calls with the EEI Member Company CEOs and senior governmental officials. EEI will also serve as the electric power industry’s primary national information resource and spokesperson. EEI will provide a broad, national perspective on the event through media and public relations activities, national stakeholder outreach, including relevant Federal agencies, social media support, and industry-wide communication and coordination to relevant stakeholders. EEI is not a member of the NREC but will work closely with the NREC and may participate in NREC and NMART activities as appropriate to carry out its functions. As set forth below, EEI will maintain exclusive ownership and control of the NRE Resource Allocation Methodology, its related tools, and all data provided by Participating Companies to the NMART to carry out its functions.

NRE Principles:

Activating an NRE. A Participating Company CEO(s) or executive designee(s) may make a request to initiate the NRE process by directly contacting the President of EEI (or his designee), who would then host a conference call with the CEO(s) or executive designee(s), the NREC Chair, and the CEO Policy Committee on Reliability and Business Continuity Chairs to validate the request and either activate the NRE, delay the decision for 6 to 12 hours (time determined by NREC Chair), or not activate the NRE. The decision on whether or not to activate the NRE will be made on this decisional call. The request can occur before or after an event impacts a region or utility. Such requests shall be based upon a high probability forecast or actual damage and careful consideration of the resources requested. Once an NRE is activated, the NREC Chair shall activate the NMART and notify the NREC members that an NRE is activated.

Activities During an NRE. NREC Members should be available throughout the NRE. The NREC Chair or Vice Chair or their respective designee from the NREC should co-locate with the NMART Chairs or Vice Chair or their respective designee from the NMART and EEI.

The NMART shall collect the necessary information to make resource allocation decisions as prescribed by its policies and procedures. The NMART will inform the NREC Chair and EEI of all allocation decisions.

Upon activation, EEI shall develop, and communicate consistent messaging for all stakeholders concerning the NRE pursuant to the EEI Crisis Communications Plan. The NREC Chair and EEI will periodically update the NRE CEOs throughout the NRE.

During an NRE, specific issues from any Participating Company CEO or designee should be addressed directly to the NREC Chair. The NREC Chair shall involve the NREC or NMART, as necessary, in the disposition of such issues, including any modification to decisions made by the NMART. Any further review of the disposition of such issues may be directed to the EEI Board of Directors.

Post-NRE Activities and Coordination. Following an NRE or exercise, the NREC shall conduct a review of the NRE process and procedures to identify any opportunities for improvement. The NREC and the NMART shall also meet at least once a year during the Spring EEI CEO meeting to provide a forum for
scheduling and execution of annual exercises and drills, sharing updates and any lessons learned, and any other pertinent business.

**Resource Allocation Tool and Data Confidentiality:**

Confidentiality of NRE activities, data and work products: During an NRE, Participating Companies may provide or receive confidential information regarding available and requested resources and the allocation thereof (“Confidential Information”). Each Participating Company agrees to hold all Confidential Information obtained from the NRE structure and process (including the NRE Resource Allocation Methodology and its related tools) in confidence, not use and not disclose the Confidential Information to anyone, including but not limited to any person, company, agency, commission, regulatory body, legal tribunal or court. Each Participating Company agrees to only share such Confidential Information with other Participating Companies and EEI.

In the event a Participating Company, any of its affiliates, or any representative of such Participating Party or any of its affiliates, is requested or required, pursuant to any applicable court order, administrative order, or official order by any government or any agency or department thereof, to disclose information obtained through the NRE structure and process, including the NRE Resource Allocation Methodology and its related tools, it will provide EEI, as representative of the Participating Companies, with prompt written notice of any such request or requirement unless prohibited by law or court order to do so and shall reasonably cooperate with EEI upon specific request to obtain such protective order or remedy. Participating Companies agree that if EEI and/or the Participating Company is not successful in precluding the requesting legal body from requiring the disclosure of the information, EEI and/or the Participating Company will only furnish that portion of the information or work product that is legally required and will exercise appropriate legal efforts to obtain reasonable assurances that confidential treatment will be accorded the information or work product.

The Participating Companies recognize the need to maintain the confidentiality of the Resource Allocation Methodology and its related tools and data. As such, each Participating Company assigns any right, title or interest in the Resource Allocation Methodology and its related tools and data to EEI to own and protect the confidentiality thereof. The Resource Allocation Methodology and its related tools and data will at all times be treated as Confidential Information as set forth above.

**Amendments**

Any changes or amendments to the NRE Structure and Principles must be approved by the NREC and communicated to the Participating Companies.

December 2013
Coordination with Public Power Utilities

In the event of an NRE, the DOE Emergency Response Team (ERT) will provide coordination calls between each of the electric sector representatives. These calls will include APPA, EEI, and NRECA.

EEI has reached out to APPA and NRECA to coordinate as much as possible in advance of an NRE. To that end, APPA has provided EEI with the following description of Public Power’s Mutual Aid Network.

Understanding Public Power’s Mutual Aid Network

Public power is a collection of more than 2,000 community-owned electric utilities, serving more than 47 million people or about 14 percent of the nation’s electricity consumers. These utilities are operated by local governments to provide communities with reliable, responsive, not-for-profit electric service. Public power utilities are directly accountable to the people they serve through locally elected or appointed officials. While of the nation’s largest cities – Los Angeles, San Antonio, Seattle and Orlando – operate publicly owned electric utilities in their communities, many public power electric utilities are small and serve 3,000 or fewer customers.

In the area of mutual aid and disaster management, public power utilities have developed mutual aid networks to ensure an expeditious and organized response for assistance. The networks are comprised of local utility-to-utility agreements, state associations, and joint action agencies. Each network has network coordinators that work together during large-scale disasters to facilitate the movement of crews and supplies from one region to the next. These networks have existed for many years and, since the late 1990’s, the American Public Power Association (APPA) has acted as a conduit for the network coordinators during large-scale disasters.

APPA also works with the National Rural Electric Cooperative Association and Edison Electric Institute to coordinate public power’s aid with cooperative and investor-owned utilities, respectively. Additionally, APPA keeps the Department of Energy, Federal Emergency Management Agency, and other federal partners abreast of recovery efforts for public power communities.

To learn more about public power’s mutual aid network, please visit publicpower.org/MutualAid or email MutualAid@publicpower.org.

EEI has also reached out to NRECA and obtained the following information via their website.

NRECA

NRECA is the national service organization for more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million consumers in 47 states and whose retail sales account for approximately 12 percent of total electricity sales in the United States.

NRECA’s members include consumer-owned local distribution systems — the vast majority — and 66 generation and transmission (G&T) cooperatives that supply wholesale power to their distribution cooperative owner-members. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable and affordable electric service.

AGA MUTUAL ASSISTANCE PROGRAM

The American Gas Association offers its members (utilities, transmission, and manufacturers/suppliers/service providers) a voluntary, no-fee mutual assistance program designed to suit the wide variation of needs of its member companies across the United States and Canada. The program is based on a coalition of AGA member companies, which agree to a set of baseline provisions that govern mutual assistance and agree to populate and maintain the AGA Mutual Assistance Database with company-specific emergency contact information, field capabilities and other key resources available for mutual assistance. The purpose of the AGA program is to supplement local, state and regional mutual assistance programs and is intended for those unprecedented man-made or natural disasters requiring the dedication of response/recovery/restoration resources outside the limits of existing mutual aid programs. The incorporation of the AGA Mutual Assistance Program into a company’s emergency planning portfolio enhances advanced planning and effectuates response efforts in time of extenuating circumstances. Point of Contact: Mike Bellman, Email:  Below is AGA’s URL if want more information. AGA held an Exercise in January 2014 and the overview and lessons learned is on their website too.

http://www.aga.org/Kc/OperationsEngineering/ngmarc/Pages/default.aspx
Appendix F: Background on a National Response Event

The purpose of the NRE Resource Allocation Process is to efficiently deliver an equitable and transparent allocation of restoration workers to EEI member companies ("utilities" or "companies") during a National Response Event. This process will be used for events in which an NRE is activated and will be used throughout the event until all resource requests have been met.

**Case for action**

In the aftermath of Superstorm Sandy, the electric utility industry developed the NRE process to enhance the existing mutual assistance process for national events because:

- Electric customers who have increasing expectations and electricity dependence need to see the mutual assistance process as efficient, transparent and equitable;
- Each individual utility or regional mutual assistance group (RMAG) plays a key role in successful response;
- The industry wants to demonstrate that it is prepared for significant events and committed to continuous improvement; and
- More efficient resource allocation would further improve public safety, accelerate restoration and reduce potential economic consequences.

**Defining a National Response Event**

A National Response Event is an electric utility event that:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.

Once the NRE is activated, all of the available resources (line workers, tree trimmers, damage assessors, logistical support, etc.) are allocated at the national level across individual companies and RMAGs based on transparent and objective criteria.

A National Response Event will also require coordination of the Federal, State and Local response.

**Project Management Office (PMO) efforts in 2013**

In the aftermath of Superstorm Sandy under EEI’s leadership, the industry undertook an effort to further enhance its mutual assistance process for large outage events. Throughout 2013, nearly 60 representatives from 36 utilities, supported by EEI staff and Davies Consulting, LLC, worked tirelessly to strengthen the industry’s capability to respond to future outage events that impact multiple regions of the country.

The request for activating the NRE should meet the following criteria regarding the actual/forecasted event:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.
In order to make necessary progress in a relatively short period of time, the team created a project management office and project structure, which is described in the following chart:

![Diagram of project management structure]

Note: Names in italics are the Executive Leads

The first phase of the NRE design was completed and presented to the EEI Board in June 2013, where the team obtained approval to continue with implementation. The initial implementation was completed in October 2013, after being tested through a set of one table top and two functional exercises.

The Executive Leads worked closely with the EEI Mutual Assistance Executive Team, representatives from most of the RMAGs and other executives. The list of contributors throughout includes individuals listed in Appendix B in alphabetical order of their utility names:

- Brad Oachs (ALLETE)
- Vern Gebhart & Tom Hess (Alliant Energy)
- Tom Kirkpatrick, Jim Nowak & Bob Powers (American Electric Power)
- David Baker (CenterPoint Energy)
- Tim Hayes & Charles Freni (CH Energy)
- Terrence Donnelly (ComEd)
- Craig Ivey, Carlos Torres & Tony Torphy (ConEd)
- Anthony Bunting (Cleco LLC)
- Rodney Blevins (Dominion)
- Melody Byrd-Birmingham, Marty Zearbaugh, & Marty Wright (Duke Energy)
- Patrick Conti & Tim Kuruce (Duquesne Light)
- Greg Grillo & Michael Fricke (Entergy)
- Randy Coleman, Mark Julian & Cheryl Scheeler (FirstEnergy)
- Kevin Walker (Iberdrola USA)
- Carol Baxter (KCP&L)
- Greg Thomas (LG&E & KU Energy)
- John Donleavy & Dave Way (National Grid USA)
- Manny Miranda (NextEra)
- Bill Quinlan & Mike Zappone (Northeast Utilities)
- Jim Reagan (NV Energy)
- Mike Mathews (OGE)
- Keith Hull, Mike Carter, & Jeffrey Dossey (Oncor)
- Debbie Guerra (PacifiCorp)
- Barry Anderson (PG&E)
- Dave Velazquez, Thomas Born & George Nelson (PHI)
- David Bonenberger (PPL)
- Booga Gilbertson (Puget Sound)
- Dana Kracke, Rachel Sherrill & Henry Martinez (SCE)
- Jim Collins (Southeastern Electric Exchange)
- Aaron Strickland, Danny Glover & Mark Crosswhite (Southern Co.)
- John Prete (UIL Holdings)
- Tom Murphy (Unitil)
- Brian Gatewood & Rich Schach (Vectren)
- Kevin Fletcher (We Energies)
- Bryan Nowlin (Westar Energy)
- Don LuMaye (WPS)
Appendix G: Frequently Asked Questions

Questions and Answers: Union Issues
Q. Are non-union crews being turned away?
A. [Local facts if known] In the case of significant outage events, electric utilities request and accept assistance from any and all qualified workers. The reports of non-union crews being turned away during Sandy were found to be untrue. Utilities in the affected areas and union representatives welcomed assistance regardless of their union status.

Questions and Answers: Cross State Lines/Blocking by Governors
Q. Why should workers be allowed to move across state lines? How do you respond to [Governor of State] who has called for crews to remain/not be allowed to cross state/not be allowed to leave?
A. A timely restoration effort requires a smooth transition of resources from other regions into the affected area, regardless of the state boundary. Utility service territories often extend beyond state boundaries and restoration work often involves multiple jurisdictions. Having flexibility to move resources to the outage location is the key to successfully completing a restoration. The electric utility industry’s mutual assistance program ensures that all available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe and efficient manner.

The investor-owned electric utility industry’s national response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving/on the road], and limiting utilities’ ability to move restoration resources in the most efficient manner undermines this process. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].

Questions and Answers: Workforce Issues
Q. Will the enhancements made to the industry’s mutual assistance program get more workers to the outage in [AREA]?
A. The investor-owned electric utility industry’s mutual assistance program now has the ability to coordinate the allocation of restoration workers on a regional and national scale, but it does not create a larger overall pool of qualified restoration workers. The industry is working on workforce development through the Center for Energy Workforce Development and with programs like Troops to Energy Jobs, but these efforts are designed to bring new workers into the industry over time.

The investor-owned electric utility industry’s response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving in the region/on the road/already at work]. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].
Questions and Answers: Hardening and Restoration

Q. Will the enhancements made to the industry’s mutual assistance program make the system stronger/prevent outages?
A. The electric utility industry’s mutual assistance program is not designed to directly address infrastructure needs. These decisions are made by utilities and regulatory bodies that determine the most cost-effective measures to strengthen the grid and make it more resilient.

Q. Will the enhancements to the mutual assistance program make the lights come on faster?
A. Due to the inherently unpredictable nature of disasters, the mutual assistance program cannot reduce the damage that may occur from severe outage events. Enhancements made to the process do scale up the industry’s mutual assistance program to address national level outages and ensure that mutual assistance is safe and efficient.

Q. Would undergrounding prevent outages?
A. The mutual assistance program is not designed to directly address infrastructure needs. However it is important to remember that some measures of reliability indicate that underground electric infrastructure has only a slightly better reliability performance than overhead electric systems, while other measures show a higher reliability factor for underground facilities. One explanation may be that many underground facilities are fed by overhead facilities which can become disabled during storms.

Repairs to underground facility outages are often more complex and time consuming and such facilities are more costly to upgrade and replace. And, as recent experiences with Superstorm Sandy demonstrate, underground facilities are very vulnerable to flooding and water damage.

Undergrounding also brings significant costs, industry data show that costs for underground transmission and distribution construction costs can be between five to 10 times greater than for overhead.

Questions and Answers: Mutual Assistance Process Specific

Q. What enhancements were made to the industry’s mutual assistance program following Superstorm Sandy?
A. The investor-owned electric utility industry has developed a new framework to institutionalize the lessons learned and best practices from Sandy in order to optimize restoration efforts following events that impact a significant population or several regions across the U.S. and require resources from multiple Regional Mutual Assistance Groups (RMAGs). In the case of significant outage events, where an industry-wide response is needed, all available industry emergency restoration resources (including contractors) will be pooled and allocated to participating utilities to safely and efficiently meet restoration needs.

A committee of senior-level member company utility executives from all regions of the country governs this allocation process, with members drawn from utilities in each of the seven RMAGs. RMAGs will continue to facilitate the process of identifying available restoration workers and help utilities coordinate the logistics and personnel involved in restoration efforts.

One of the important lessons learned following Superstorm Sandy was that there were too many small RMAGs in the Northeast. In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group
(NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven.

This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increase the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

The electric utility industry continues to collaborate and work with the federal government and the states to enhance and formalize industry-government partnerships developed during Superstorm Sandy. These efforts include:

- Improving communication and coordination by embedding senior industry officials with government response teams at the U.S. Department of Energy and coordinating with the Federal Emergency Management Agency.

- Streamlining transportation by developing information resources and tools to expedite the movement of resources across state lines in partnership with the U.S. Department of Transportation and state transportation agencies. Additionally, we have negotiated a new procedure for U.S. and Canadian border crossings with the Department of Homeland Security and the Canadian Border Services Agency to minimize delays and to ensure timely movement of mutual assistance crews across the international border.

- Engaging in an ongoing dialogue with the Department of Defense (DOD) to enhance logistical support, such as access to DOD property and facilities for pre-staging areas, exploring ways to enhance security and road access with the National Guard, and securing access to critical supplies and equipment from the Army Corps of Engineers.

Q. Specifically how does the mutual assistance program allocate response resources?
A. The national allocation of response resources uses a formula that takes into account the proportion of customer outages and the proportion of trouble spots relative to all requesting utilities. Additional qualitative refinements to the allocation may also be made based on geography, travel routes, type of damage, and other factors that can affect restoration. After the allocation, resource matching to individual utilities is conducted through Regional Mutual Assistance Groups (RMAGs) based on local requirement. Reallocation of resources is also built into the process so restoration workers and equipment can be effectively redeployed throughout an event. The process is designed to make an efficient and equitable allocation based on need.

Q. What are the specific numbers?
A. [EEI will release national numbers based on information from the NREC/NMART.]
## Appendix H: Glossary of Terms

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
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<tr>
<td>Analytic Team</td>
<td>Designated members of NMART Team (EEI MA Executive Committee) that will review allocations output and make preliminary RMAG assignments prior to NMART call.</td>
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<tr>
<td>Company resources</td>
<td>Resources that work on a utility property on a blue sky day at the time of the event, including contractors.</td>
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<tr>
<td>Continuous Improvement</td>
<td>Ongoing effort to review and improve the current business practices.</td>
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<tr>
<td>Contractor</td>
<td>Company that provides resources and equipment (line, tree, etc.) to an IOU through a contractual agreement.</td>
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<tr>
<td>Customer</td>
<td>Metered facility serving electricity to one residence, business or industry. Does not include outdoor lighting.</td>
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<tr>
<td>Customer Outage (sustained)</td>
<td>Sustained distribution outage longer than 5 minutes.</td>
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<tr>
<td>Damage Assessor</td>
<td>FTE that goes into the field and evaluates and records damage to an electrical system.</td>
</tr>
<tr>
<td>Full Time Equivalent (FTE)</td>
<td>Resources are counted as individual workers versus using the term of “Crew”. Crew is defined in many different ways across the industry, so for consistency purposes, the mutual assistance discussions are based on FTE counts.</td>
</tr>
<tr>
<td>Investor Owned Utility (IOU)</td>
<td>Utility that is owned by investors. Does not include Co-Operatives, Municipal owned systems, etc.</td>
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<tr>
<td>Non-Native Resources</td>
<td>Resources that are not on a utility system on a daily basis. Non-Native includes sister company resources.</td>
</tr>
<tr>
<td>Off-system resources</td>
<td>Resources that are not working on a utility system on a daily basis (includes contractors &amp; sister companies)</td>
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<tr>
<td>Reallocation</td>
<td>In the unlikely event that a utility has a larger share of the workforce and it is obvious, it may be asked to release some portion of workers and move them to another utility. This is a last resort effort.</td>
</tr>
<tr>
<td>Redeployment</td>
<td>Once a utility has made progress and cannot utilize all resources efficiently, they will begin a release of a portion (or all) outside resources to assist others.</td>
</tr>
<tr>
<td>Requesting company</td>
<td>Company that has been impacted with outages and is receiving resources from others.</td>
</tr>
<tr>
<td>Resource request (Pre-staging)</td>
<td>Resource requests for pre-staging should be the summation of resources acquired plus additional needs at this point in time. This should be a maximum number that you would take at this point in time.</td>
</tr>
<tr>
<td>Resource Request (Allocations)</td>
<td>Resource requests for allocations should be the maximum incremental number of resources that you would take at this point in time.</td>
</tr>
<tr>
<td>Responding company</td>
<td>Company that provides resources to assist in restoring power for an impacted company.</td>
</tr>
<tr>
<td>Cases of Trouble</td>
<td>One case of trouble representing a device that is damaged and in need of repair in order to restore the service to their customers.</td>
</tr>
<tr>
<td>Utility</td>
<td>Business entity that provides electrical service to customers.</td>
</tr>
</tbody>
</table>
Appendix I: Communications Checklists and Templates

Checklist -- How To Activate the Storm Center as the www.eei.org Home Page

*Slide Show Images*
Update images for use in the slide show at the top of the page. Images are 600px x 360px. The images in this folder will be shown in the slide show. Delete any images that should not be on the home page.
http://www.eei.org/SiteCollectionImages/Forms/Thumbnails.aspx?RootFolder=%2FSiteCollectionImages%2FFima%2Fslider

*Edit Title*
Edit page http://www.eei.org/Pages/ma.aspx to include the new Title.

*Edit Storm Center Multimedia Page*
Set up the multimedia gallery by editing the storm center page in the Mutual Assistance section under the Electric Reliability issue.
http://www.eei.org/issuesandpolicy/electricreliability mutualassistance/Pages/default.aspx

*Update Map of Affected States*
When appropriate shade and update map. Verify the companies’ outage center links of affected states. If they need to change edit, this list:
http://www.eei.org/Lists/Company%20Storm%20Sites/AllItems.aspx
Shade affected states and post new image here: http://www.eei.org/SiteCollectionImages/ma/storm-map.jpg

*Activate New Home Page*
1. From the current home page select “Site Actions”
2. Select “Site Settings”
3. Under “Look and Feel” select “Welcome Page”
4. Change “default.aspx” to “ma.aspx”
5. Hit “OK”

Checklist -- Reporter’s List Guide
All lists of reporters are located on Vocus under media contacts lists.
- Energy and Utilities List: 345 Energy and Utility reporters
  - Printed and organized by Outlet Name
- Master Media List: 287 Reporters Covering Multiple Topics
  - Printed and organized by Outlet Name
- National Media List: 865 Assignment Desk Reporters
  - On Vocus
- RMAG Assignment Desk Lists: on Vocus
  - Midwest RMAG: ND, SD, NE, KS, MO, CO
  - Western RMAG: MT, WY, NV, AZ, NM, ID, UT, CA, OR, WA
  - Texas RMAG: TX, OK, AR
  - Wisconsin RMAG: WI, MN, IA
  - Southeast RMAG: FL, GA, AL, LA, MS, SC, NC, VA
  - Great Lakes RMAG: TN, KY, IN, IL, MI, OH, WV
  - North Atlantic RMAG: MD, DE, PA, NJ, NY, MA, CT, VT, ME, RI, NH

Template -- Generic Preparedness Message

Be Prepared, Be Safe.

What you can do now:

- Read EEI's [Type of Event] safety tips.
- Develop an emergency plan that addresses any special medical needs you or your family members have. Call your local emergency management office to discuss necessary arrangements.
- Have your Emergency Outage Kit stocked and readily available.
- Know all evacuation routes.
- Pay attention to local weather reports on the radio, television, or Internet.
- Stock up on non-perishable food, water, medications, and any other necessities to avoid the need for travel during the storm. If called to evacuate, do so immediately.
- Learn what to do in case of a power outage.

If a severe storm does hit your area:

- Stay in a secure room and away from windows. Remain indoors.
- Monitor weather bulletins on a battery-powered radio.
- If your power goes out, report your outage immediately to your local electric company. Don’t rely on your neighbors to report your outage.

Severe Weather and Reliability

In addition to customer safety, the electric power industry’s top priority is to provide a reliable supply of on-demand power. Discover how the industry responds to outages caused by severe weather:

- Review the power restoration process.
- Learn about the industry’s Mutual Assistance Network.

Don’t forget to visit your local electric company’s Web site for the latest updates and guidance on how to prepare for storms.
Email to CEOs about NRE Activation

TO: EEI CEOs
CC: Communicators, External Affairs (State/Local Contacts), Mutual Assistance and Emergency Preparedness Committee, Business Continuity Task Force, and NREC/NRE/RMAG distribution lists.
FROM: Tom Kuhn/Crisis Management Officer
DATE: [DA/MO/YEAR]

As you know [NRE EVENT] is forecast to impact [REGION].

[SITUATIONAL ANALYSIS AS NEEDED].

Based on the [NRE EVENT FORECAST/EXISTING CONDITIONS/IMPACT OF NRE EVENT] and the recommendation of EEI CEO(s), the National Response Executive Committee (NREC) has activated our National Response Event (NRE) framework.

An NRE is a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). During an NRE, our mutual assistance program is coordinated at the national level by the NREC and restoration resources are allocated by the National Mutual Assistance Resource Team (NMART) to deliver a safe, efficient, and equitable allocation of restoration workers and contractors.

EEI has activated its crisis management plan to address this NRE.

Throughout the NRE, we will be hosting daily CEO calls to discuss events (timeline below) and the NREC chair will update CEOs on these calls.

Timeline for CEO Calls
3:30 PM EDT – CEOs directly affected by [NRE EVENT]
4:30 PM EDT - All CEOs
5:15 PM EDT - CEOs and Government/External partners

The predetermined call number is 1-412-717-9582 / ask for “EEI NRE Call”. Agendas are attached.

Our communication team will be preparing daily talking points on the NRE for internal and external audiences, a copy is attached.

We have also attached a roster of the NREC members and EEI staffing chart.
Template -- NRE Industry Communicators Conference Call Agenda

7 PM Eastern (Daily during NRE/Event)
Call-in Number: 1-800-882-3610
Guest Code: 4731734
Host Code: 0452833

Agenda

1. NRE/Event Status
   a. Event outage overview (total out, % restored, progress, unable to energize)
   b. Topline resource allocation and response summary (process update, total responding, resources allocated through NRE)
   c. Review of broader resource and restoration challenges and issues being addressed by EEI (as needed)
      i. Logistics/Transportation/Access/Lodging/Security/Equipment
      ii. Political issues
      iii. Federal actions
   d. CEO Conference Call Summary and Update

2. Company Restoration Status Review
   a. Input from companies on their restoration progress
   b. Successes
   c. Challenges
   d. Special considerations/issues
   e. Comparison to overall numbers

3. Daily Industry Message Update
   a. Review EEI industry messages/talking points
   b. Highlights from daily email/messaging/visual report

4. Company Messaging Review
   a. Input from companies on their messaging
   b. Share messaging examples
   c. Channels/Tactics that are working well
   d. Any unique/special messages

5. Communication Challenges/Successes
   a. Input from companies
   b. What’s working well?
   c. What’s not working?
Template -- NRE Talking Points (Pre-Event)

[NRE EVENT NAME]  
Time, Date  
Prepared By EEI Communications

Top Line  
Utilities in the projected path of [NRE EVENT NAME] are prepared and if you live in the projected path you need to be prepared too.

Storm Update  
The latest update from NOAA indicates that [NRE EVENT NAME] is a [EVENT DESCRIPTION] and may [EVENT IMACT TIMING].

The Edison Electric Institute (EEI), along with the investor-owned electric utility industry’s Regional Mutual Assistance Groups (RMAGs) and the utilities in the projected path, continue to closely monitor the storm and its intensity and are taking steps now to prepare.

Utilities in the projected path are prepared to respond to any customer outages that may occur. If called upon, restoration crews are prepared to travel to impacted areas, and utilities remain in constant contact with their RMAG. Additionally, if conditions warrant, the industry is prepared to scale our mutual assistance efforts to the national level so industry restoration resources are allocated in a singular and seamless fashion.

Be Prepared. Be Safe.  
If you live in the forecasted path of [EVENT DESCRIPTION], now is the time to prepare. Electric customers are encouraged to prepare for the possibility of sustained power outages by taking action before [NRE EVENT NAME] makes landfall. For safety tips and updates visit the Edison Electric Institute website, www.eei.org, or your local utility’s website.

[EVENT DESCRIPTION/WEATHER UPDATE] (Time, Date, Source)

•

•

•

Mutual Assistance Program  
RMAGs continue to monitor [NRE EVENT NAME]. At this time, a National Response Event has not been activated, but the industry is closely monitoring the situation and will be ready to activate if conditions warrant. The investor-owned electric utility industry defines a National Response Event (NRE) as a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). It’s important to understand an NRE designation is reserved only for the most significant events, such as a major storm, earthquake, an act of war, or other occurrence that results in widespread power outages.

Thoughts & Prayers Message  
EEI and its member electric power companies understand that power outages of any duration are hugely disruptive to peoples’ lives, which is why we are preparing now for [NRE EVENT NAME]. Through the electric power industry’s Mutual Assistance Program, impacted member companies will be able to request restoration workers and respond to outages as safely and quickly as possible. In the event of outages, our industry is committed to working around the clock, to get every last customer’s lights turned back on.
Template -- NRE Talking Points (During Event)

Template -- [NRE EVENT NAME]
Time, Date
Prepared By EEI Communications

Top Line
The damage left in the wake of [DAMAGE ASSESSMENT – states/customers impacted, outages]. Restoring power as safely and efficiently as possible is the electric power industry’s number one priority. First responders, aid workers, and utility workers are the true unsung heroes.

Electric utility companies affected by [NRE EVENT NAME] have been working around-the-clock to assess the damage/restore power to millions of customers. Prior to [NRE EVENT NAME], utility companies mobilized thousands of storm response personnel and called upon extra workers and resources from all across the country through the industry’s Mutual Assistance Network.

Mutual Assistance Overview
EEI’s mutual assistance network—a voluntary partnership of investor-owned electric utilities from across the country—leverages the strength, skills, and resources of participating utilities to help restore power after an emergency situation. Through the network, affected electric utilities are able to “borrow” skilled restoration workers—both utility employees and contractors—along with specialized equipment from other utilities that participate in one or more of our seven Regional Mutual Assistance Groups (RMAGs). Municipal utilities and electric cooperatives also have their own mutual aid programs that provide restoration support to their participating utilities.

The current mutual assistance program works well for regional events, but was not designed to be scalable for national events.

NRE Activated
Due to the significant size and scope of [NRE EVENT NAME], the investor-owned electric utility industry activated [NRE EVENT NAME] a “national response event” (NRE) on [DATE]. During an NRE, our mutual assistance program is coordinated at the national level to deliver a safe, efficient, equitable allocation of restoration workers and contractors to participating utilities.

Storm Update
The latest update from NOAA indicates that [NRE EVENT NAME] is a [EVENT DESCRIPTION] and may [EVENT IMACT TIMING/DURATION].

Restoration Outage Overview
Customers impacted:
Percent of customers out in impacted states:
Impacted States/Custumers Out:

Safety Message
Restoring power as safely and efficiently as possible is the electric power industry’s number one priority. Customers need to be prepared for the possibility of extended outages due to the enormity of [NRE EVENT NAME]. Although our industry prepared for [NRE EVENT NAME] by pre-staging restoration workers and equipment near affected areas, [NRE EVENT NAME] damaged the electric system, blocked roads, and created hazardous working conditions for people in the area.

Restoration workers always put safety first, and we urge the public to be patient and to stay clear of fallen power lines and avoid standing water that could hide damaged electrical equipment or other dangerous objects.
For safety tips and updates visit the Edison Electric Institute website, www.eei.org, or your local utility’s website.

**Thoughts & Prayers Message**
Our hearts and prayers go out to those affected by [NRE EVENT NAME]. We know that people without electricity face very real hardships. And we deeply appreciate their understanding and patience as utility crews go about their vital jobs of restoring power under extremely challenging and dangerous circumstances. Our entire industry will give it everything it has, working around the clock, to restore power as safely and efficiently as possible.

**Industry-Government Coordination**
Because of the severity of [NRE EVENT NAME], industry and government officials are closely coordinating to identify potential barriers and areas where federal and state governments would be able to assist during the response and restoration process.

**Other Key Talking Points As Needed** (See “Canned Messages”)

Template -- Opt Out Email for External Stakeholders

As you know, [Storm Name] is [expected to / has impacted] several states. Due to the [severity / forecasted severity] of [Storm Name], The [Mutual Assistance Network / industry-wide National Response Event (NRE) process] has been activated, which allows the investor-owned electric utility industry to coordinate its storm restoration response to [Storm Name] at the national level [(only if NRE) in order to ensure industry restoration resources are seamlessly allocated in the most safe and efficient manner possible].

Through the duration of [Storm Name], EEI will be distributing daily news clips and summary reports reviewing the industry’s restoration progress; the first summary report is attached. If you do not want to continue to receive these daily updates, please click on this link to opt-out of these reports. [OPT OUT LINK]

**Background**

In the aftermath of Superstorm Sandy, the investor-owned electric utility industry recognized the value of enhancing and formalizing the mutual assistance process for events that require a national, industry-wide response. For outage events that require a national response, the investor-owned electric utility industry will activate an industry-wide “national response event” (NRE). An NRE is a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). Municipal utilities and electric cooperatives also have their own mutual aid programs that provide restoration support to their participating utilities.
Template – Outage Overview

[Storm/Event]
Updated Briefing Points
[Time, Date]
Prepared By EEI Communications

Restoration Outage Overview
- Customers impacted: 0 (Sandy: 10 million; Irene: 7 million; Derecho: 5 million)
- Current outages: 0 (EEI – Time, Date)
- Total restored: 0 (EEI – Time, Date)
- Percent restored:
- Outages restored last 24 hours
- Percent restored that could be energized: TBD
- Customers unable to energize: [Total]; [MC 1]; [MC 2]; [MC 3]
- Current outages/peak outages: [State 1]: [CO/PO]; [State 2]: [CO/PO]; [State 3]: [CO/PO]
- Estimated Economic Damage: $ (Citation)
- Restoration Update: An army of [Number] ([Number] utility companies)—from as far away as [Canada], [California] & [Hawaii]
- Death Toll: [Number] in [Number] states; [State 1]: [Number]; [State 1]: [Number] (Citation)

<table>
<thead>
<tr>
<th>Days</th>
<th>Date</th>
<th>Outages</th>
<th>Percent Restored</th>
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</table>
FOR IMMEDIATE RELEASE

EEI, Electric Utility Industry Prepare for [NRE EVENT NAME]

Washington, DC (Day, Date) – With [NRE EVENT NAME] expected to impact [STATES/LOCATIONS], the electric utilities companies in the forecasted path are taking steps now to prepare. [NRE EVENT NAME] [EVENT DESCRIPTION/EXPECTED IMPACTS]. Electricity customers are encouraged to prepare for the possibility of sustained power outages by taking action before [NRE EVENT NAME] [EVENT DESCRIPTION/EXPECTED IMPACTS].

“With [NRE EVENT NAME] predicted to strike as early as [DAY/DATE], we urge customers to put safety first and be ready should severe weather reach their areas,” said EEI President Tom Kuhn. “EEI and its member electric utility companies understand that power outages of any duration are hugely disruptive to peoples’ lives, which is why we are preparing now for [NRE EVENT NAME].”

No pre-deployment: Electric utility companies in the region are initiating their storm response plans. And, the investor-owned electric utility industry’s Regional Mutual Assistance Program is ready to provide restoration support by calling upon extra workers and resources from all across the country in order to restore service as safely and efficiently as possible.”

Pre-deployment: Through the investor-owned electric utility industry’s Regional Mutual Assistance Program, many of our member companies have already begun the process of pre-mobilizing tens of thousands of storm and field personnel, and calling upon extra workers and resources from all across the country to assist if the power goes out in order to restore service as safely and efficiently as possible.”

STORM CENTER NOT ACTIVATED: On the EEI web site utility customers can find safety tips and information about how electric service is restored. EEI also encourages utility customers to follow EEI’s social media sites on Twitter and Facebook.

STORM CENTER ACTIVATED: On the EEI Storm Center site utility customers can find safety tips, links to customers’ own electric company’s outage centers, real-time information and updates on storm preparation and restoration progress. EEI also encourages utility customers to follow EEI’s social media sites Twitter and Facebook.

# # #

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity to 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. EEI has 70 international electric companies as Affiliate Members, and 250 industry suppliers and related organizations as Associate Members.
FOR IMMEDIATE RELEASE
FOR INFORMATION CONTACT:
[EEI MEDIA RELATIONS CONTACT, PHONE #]

Investor-owned Electric Utility Industry Activates Industry-Wide National Response to [NRE EVENT NAME]

WASHINGTON, DC [(Day), (Date)] — The investor-owned electric power industry today activated its industry-wide national response event plan to mobilize a major restoration effort to address the significant outages that are expected from/that occurred as a result of [NRE EVENT NAME].

Due to the size and severity of [NRE EVENT NAME], the electric power industry has designated [NRE EVENT NAME] an industry-wide “national response event” (NRE). “During an NRE, our member companies’ mutual assistance program is coordinated at the national level to deliver a safe and efficient allocation of restoration workers and contractors,” said EEI President Tom Kuhn. “By coordinating the industry’s response in this fashion, we can increase public safety, accelerate the industry’s response, and minimize economic consequences for consumers and the nation.”

In the aftermath of Superstorm Sandy, EEI member companies recognized the need to enhance its mutual assistance program—which is a voluntary partnership of investor-owned electric utilities from across the country—for events that cause significant power outages and require a national industry response. NRE declarations are reserved for the most significant outage events, such as a major storm like [NRE EVENT NAME], earthquakes, an act of war, or other occurrence that results in widespread power outages.

Under the industry’s NRE framework, mutual assistance is overseen by a new National Response Executive Committee (NREC), comprised of senior-level member utility executives from all regions of the country. The NREC has activated a National Mutual Assistance Resource Team (NMART) that will evaluate mutual assistance requests and assign available resources to participating utilities through the industry’s established mutual assistance program. This allows investor-owned electric utilities to efficiently coordinate and scale their restoration resources to create a coordinated, national response for major events.

EEI continues to update its Storm Center site with safety tips, links to customers’ own electricity providers’ outage centers, real-time information, and updates on storm preparation and restoration progress. More information about storm restoration can also be found at EEI’s social media sites on Twitter and Facebook.

###

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Template -- Scheduled Tweets:

Visit the EEI Storm Center at http://www.eei.org for safety tips and updates on storm preparation and restoration progress. #StormName

What is mutual assistance and how does it work when a storm like #StormName strikes? Find out here: http://ow.ly/eOFwn

Should #StormName cause outages, your electric company will take the following steps to get your power back on: http://ow.ly/eOH23

All you need to know about preparing for and staying safe during a power outage: http://ow.ly/eOJbO #StormName

Keep track of the electric power industry's response to #StormName by checking out our Storm Center at http://eei.org .

As #StormName hits, remember safety comes first for crews and customers. Check out http://eei.org for tips for you and your family.

Our members will work tirelessly to get power back on in the wake of #StormName. Here's how restoration works: http://ow.ly/eONgt

Mutual assistance network is activated & thousands from across the country are already restoring power. More at http://eei.org . #StormName

What is mutual assistance and how does it work? Find out here: http://ow.ly/eRmZU #StormName

Millions are without power due to #StormName. Learn the steps your electric company takes to restore power: http://goo.gl/HHZgl

Restoring power is a multi-step process, and safety always comes first. Learn how power gets restored: http://ow.ly/eT5tu #StormName

Mutual assistance going strong to restore power quickly. Want to know how it works? Read about it here: http://ow.ly/eTEAz #StormName

Stay safe during a power outage by following these tips: http://ow.ly/eUhS7 #StormName

Tens of thousands are working to restore power. Get the latest #StormName recovery updates from our Storm Center at http://www.eei.org .

Utility workers from all across America are rushing to areas affected by #StormName to restore power. http://www.eei.org
### National Response Event Check List for TTX, FX, Activation

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<th>Task</th>
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<th>Conference Room</th>
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<td>• Reserve TAE Conference Rooms</td>
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<td>• After hour facilities notification and HVAC system</td>
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<td>• Food/Beverage</td>
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<td><strong>Materials</strong></td>
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<td>• Tent Cards/Badges</td>
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<tr>
<td>• NRE Handbook (playbook)</td>
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<td>• Paper/pens</td>
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<td>• Power strips to accommodate 6 attendees</td>
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<td>• Projector /screen</td>
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<td>• Talking points – Comms. Officer</td>
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Points of Contacts

Information Technology

Phones, Webinar
Webinar (i.e., Live Meeting)

Lead IT Customer Support (Eddie Jreidini)
Office:
Email: [REDACTED]

Printers

Manager, Operation /IT Customer Support (Jeanny Ho)
Office:
Email: [REDACTED]

Internal Service Center

Facilities processes and procedures
After hour/weekend access to 701 Penn
HVAC
After hour/ reserve conference room
and logistics set up
Catering (food/beverage)

Dir. Internal Services (Jennifer McKinney)
Office:
Cell:
Email: [REDACTED]

Member Services

NetForum Database
List Servers

Assoc. Management System Coordinator (Lee Hutchinson)
Office:
Email: [REDACTED]

Energy Delivery

Research hotel accommodations and
disseminate information

Administrative Manager (Judy Mastin)
Office:
Mobile:
Email: [REDACTED]
The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers.

With $90 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans.

EEI has 70 international electric companies as Affiliate Members, and 270 industry suppliers and related organizations as Associate Members.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at www.eei.org.
# Electric Distribution Emergency Preparedness and Response Plan

## Appendix 10
EPRP Contact Lists

**Effective Date:** 9/30/2014  
**Version No.:** 1

## EPRP Appendix 10 EPRP Contact Lists
Emergency Preparedness and Restoration Plan Contact List

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<thead>
<tr>
<th>EPRP Reference</th>
<th>Name/Organization</th>
<th>Incident Command Section</th>
<th>Storm Role</th>
<th>Office</th>
<th>Mobile</th>
<th>Home</th>
<th>Reporting Location/Operations Center</th>
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<td>Transformers</td>
<td>Distribution</td>
<td>All</td>
<td>Quarterly Inspection</td>
<td>Bushing oil level inspection. Perform a visual inspection to check the oil level.</td>
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<td>Perform functional test. Monitor fan operation and listen for abnormal noise.</td>
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<td>Perform visual inspection. Check bushings for contamination and damaged insulation.</td>
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<td>Perform visual inspection. Perform a visual inspection of the transformer, LTC, bushings, gaskets, valves, piping and welds for oil leaks and check oil levels.</td>
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<td>Perform visual inspection. Perform visual inspection of temperature indicators, and compare readings with other indicators at the station. Record and trend results.</td>
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<td>Perform visual inspection. Check for obstructions and valve positions.</td>
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<td>Record LTC counter readings. Check and record LTC counter reading. Record position indicator present position, high and low.</td>
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<td>Perform visual inspection. Inspect control cabinet</td>
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<td>Record demand. Record Load Demand Meter Readings</td>
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<td></td>
<td>Perform visual inspection. Inspect Primary Fuses</td>
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<td></td>
<td>Perform visual inspection. Check nitrogen system regulator</td>
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<td></td>
<td>In service Diagnostic Maintenance</td>
<td></td>
<td>Perform Dissolved Gas Analysis (LTC)</td>
<td>Sample oil in the LTC compartment for DGA and Mini-Screen. Send to system lab for analysis. Lab will record and trend results. If results are above a specified limit or abnormal gas ratios, investigate and recondition as required.</td>
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<td>Perform Dissolved Gas Analysis (Main)</td>
<td>Sample oil in main tank for DGA and Mini-Screen. Send to system lab for analysis. Lab will record and trend results. If results are above a specified limit or abnormal gas ratios, investigate and recondition as required.</td>
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<td>Perform functional test.</td>
<td>Prove the operation of the LTC manual/automatic control loop and ensure regulatory voltage tolerances are maintained.</td>
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<td></td>
<td>Perform infrared scan.</td>
<td>See Infrared Inspection Plan and Guidelines. Check on temperature differential between main tank and LTC compartment.Look for temperature inconsistencies in radiators.</td>
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<td>Out of Service Diagnostic Maintenance</td>
<td></td>
<td>Insulation Power Factor Test</td>
<td>Perform power factor test in conjunction with maintenance of associated transformer. Record and trend results for age exploration. Review results with respect to determining the effectiveness of this test.</td>
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<td>Perform insulation resistance test</td>
<td>Perform watts loss Doble test in conjunction with transformer power factor tests. Record and trend results.</td>
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<td>Perform Excitation Test</td>
<td>Perform winding excitation test in conjunction with maintenance of associated transformer. Record and trend results for age exploration. Review results with respect to determining the effectiveness of this test.</td>
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<td>LTC Overhaul</td>
<td></td>
<td>Perform functional test.</td>
<td>Perform a functional test of tap changer in conjunction with preventative maintenance of associated apparatus. Listen for abnormal operation. Record and trend results.</td>
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<td>Perform functional test.</td>
<td>Verify temperature alarms with cooling equipment operation, in conjunction with LTC maintenance.</td>
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<td>Perform visual inspection.</td>
<td>Inspect current boxes for leaks or loose connections.</td>
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<td>Perform internal inspection.</td>
<td>Inspect and adjust operating mechanism and assess condition of stationary and arcing contacts. Filter tap changer oil. Inspect and clean load tap changer compartment.</td>
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<td>Check fault pressure relay</td>
<td>Check Fault Pressure Relay</td>
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<td>Check nitrogen system</td>
<td>Check nitrogen system regulator &amp; alarms</td>
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<td>Test fuses.</td>
<td>Perform air flow test on S&amp;C Power fuses if applicable.</td>
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<td>Transformer Maintenance</td>
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<td>Perform internal inspection.</td>
<td>Filter and condition oil. Visually inspect internal components and connections for abnormalities and tightness.</td>
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<td>Equipment</td>
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<td>Breakers</td>
<td>Distribution</td>
<td>Oil &lt;= 60 gallon</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Check breaker for mechanical integrity.</td>
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<td>Perform visual inspection.</td>
<td>Check breaker for oil leaks and gauge for clarity.</td>
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<td>Perform visual inspection.</td>
<td>Check for expected indication and condition of monitoring lights.</td>
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<td>Record and verify operations.</td>
<td>Record counter reading. Record number of fault operations. Record relay targets.</td>
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<td>Perform visual inspection.</td>
<td>Check primary drops from disconnects.</td>
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<td>Perform visual inspection.</td>
<td>Check physical grounds on all breakers.</td>
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<td>Perform visual inspection.</td>
<td>Check all breakers monitor light in cont. house &amp; segs.</td>
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<td>Record circuit loading.</td>
<td>Record circuit loading for each phase.</td>
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<td>Annual In service Diagnostic Maintenance</td>
<td>Perform infrared scan.</td>
<td>See Infrared Inspection Plan and Guidelines for details.</td>
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<td></td>
<td>Insulating oil visual inspection.</td>
<td>Sample and visually inspect oil. If excessive moisture is present, investigate source of moisture and perform field dielectric test or</td>
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<td>send sample to lab for complete oil quality testing. If dielectric strength is &lt; 22kV, recondition or replace oil as required. If oil is</td>
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<td>excessively dark (light cannot be seen through the oil), send sample to lab for oil quality testing, investigate fault duty on breaker and</td>
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<td>recondition or replace oil as required. Track and trend results for age exploration.</td>
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<td>Function Test</td>
<td>Trip and close circuit breaker.</td>
<td>Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that</td>
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<td>can be bypassed or transferred internal to the station without dropping load.</td>
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<td>Out of Service Diagnostic Maintenance</td>
<td>Lubricate mechanism.</td>
<td>Perform a visual inspection of the mechanism lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.</td>
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<td>Perform timing test.</td>
<td>Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.</td>
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<td>Perform contact resistance test.</td>
<td>Perform test in conjunction with other tests. If the load path resistance differential measurement is greater than 25% or the actual resistance is greater than specified micro-ohms investigate the cause. Record and trend results for age exploration.</td>
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<td></td>
<td>Trip and close circuit breaker.</td>
<td>Vary trip and close operation of breaker (SCADA).</td>
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<td>Insulating oil quality and dielectric test</td>
<td>Sample and analyze oil quality (field dielectric test). If dielectric strength is &lt;22 kV, recondition or replace oil as required.</td>
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<td>Breaker</td>
<td>Overhaul</td>
<td></td>
<td></td>
<td>Inspect interrupter assembly.</td>
<td>Perform overhaul and check adjustment of interrupter assemblies. Record and trend results for age exploration.</td>
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<td>Perform timing test.</td>
<td>Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.</td>
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<td>Insulating oil quality.</td>
<td>Obtain samples from each tank for lab DGA and oil quality analysis. Filter oil and correct deficiencies. Sample and analyze oil quality (field dielectric test). If dielectric strength is &lt; 22kV, recondition or replace oil as required.</td>
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<td>Perform contact resistance test.</td>
<td>Perform test in conjunction with other tests. If the load path resistance differential measurement is greater than 25% or the actual resistance is greater than specified micro-ohms investigate the cause. Record and trend results for age exploration.</td>
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<td>Inspect and adjust operating mechanism and assess condition of stationary and arcing contacts.</td>
<td>Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of stationary and arcing contacts. Record and trend results for age exploration.</td>
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<td>Inspect solid dielectric.</td>
<td>Perform visual inspection of solid dielectric in conjunction with an overhaul of associated breaker. Record and trend results for age exploration.</td>
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<td>Trip and close circuit breaker.</td>
<td>Vary trip and close operation of breaker (SCADA).</td>
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<td>Equipment</td>
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<tr>
<td>Breakers</td>
<td>Distribution</td>
<td>Old &gt; 60 gallon</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection:</td>
<td>Check breaker for mechanical integrity.</td>
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<td>Perform visual inspection:</td>
<td>Check breaker for oil leaks and gauge for clarity.</td>
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<td>Perform visual inspection:</td>
<td>Check gauge for expected indication and condition. Record for age exploration.</td>
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<td>Record and verify operations:</td>
<td>Record counter reading. Record number of fault operations. Record relay targets.</td>
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<td>Perform visual inspection:</td>
<td>Check primary drops from disconnects.</td>
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<td>Perform visual inspection:</td>
<td>Check physical grounds on all breakers.</td>
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<td>Perform visual inspection:</td>
<td>Check all breakers' monitor light in control house &amp; switches.</td>
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<td>Record and verify operations:</td>
<td>Record circuit loading. Record circuit loading for each phase.</td>
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<td>Annual In Service Diagnostic Maintenance</td>
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<td>Perform infrared scan:</td>
<td>See Infrared Inspection Plan and Guidelines.</td>
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<td>Functional Test</td>
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<td>Trip and close circuit breaker:</td>
<td>Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.</td>
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<td>Out of Service Diagnostic Maintenance</td>
<td>Lubricate mechanism:</td>
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<td>Perform visual inspection:</td>
<td>Perform visual inspection in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td>Perform power factor test:</td>
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<td>Perform visual inspection:</td>
<td>Perform visual inspection in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td>Perform time/travel test:</td>
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<td>Perform visual inspection:</td>
<td>Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.</td>
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<td>Perform contact resistance test:</td>
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<td>Perform visual inspection:</td>
<td>Perform test in conjunction with other tests. If the load path resistance differential measurement is greater than 25% or the actual resistance is greater than specified micro-ohms investigate the cause. Record and trend results for age exploration.</td>
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<td>Trip and close circuit breaker:</td>
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<td>Insulating oil quality and dielectric test:</td>
<td>Sample and analyze oil quality (field dielectric test). If dielectric strength is &gt;22 kV, recondition or replace oil as required.</td>
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<tr>
<td>Breaker Overhaul</td>
<td>Inspect interrupter assembly:</td>
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<td>Trip and close circuit breaker:</td>
<td>Perform overhaul and check adjustment of interrupter assemblies. Record and trend results for age exploration.</td>
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<td></td>
<td>Perform time/travel test:</td>
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<td></td>
<td>Insulating oil quality:</td>
<td>Obtain samples from each tank for lab DGA and oil quality analysis. Filter oil and correct deficiencies. Sample and analyze oil quality (field dielectric test). If dielectric strength is &gt;22kV, recondition or replace oil as required.</td>
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<td></td>
<td>Perform contact resistance test:</td>
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<td></td>
<td>Perform power factor test:</td>
<td>Perform power factor test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td></td>
<td>Inspect/adjust operating mechanism and assess condition of contacts:</td>
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<td>Perform power factor test:</td>
<td>Perform power factor test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td></td>
<td>Trip and close circuit breaker:</td>
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<td></td>
<td>Inspecting solids dielectric:</td>
<td>Perform visual inspection of solid dielectric in conjunction with an overhaul of associated breaker. Record and trend for age exploration.</td>
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<td>Equipment</td>
<td>Type</td>
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<td>Proposed Activity Name</td>
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<tr>
<td>Breakers</td>
<td>Distribution</td>
<td>Free Standing Vacuum</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection. Check breaker for mechanical integrity.</td>
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<td>Perform visual inspection. Check breaker and bushings for contamination and damaged insulation.</td>
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<td>Record and verify operations. Record counter reading. Record number of fault operations. Record relay targets.</td>
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<td>Check breakers. Assure that all heaters are functional.</td>
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<td>Perform visual inspection. Check physical grounds on all breakers</td>
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<td></td>
<td>Perform visual inspection. Check primary drops from disconnects</td>
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<td></td>
<td>Perform visual inspection. Check all breakers monitor light in cont. house &amp; swgrs</td>
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<td>Record circuit loading. Record circuit loading for each phase.</td>
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<td></td>
<td>Annual In service</td>
<td>Functional Test</td>
<td>Perform infrared scan. See Infrared Inspection Plan and Guidelines for details.</td>
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<td>Trip and close circuit breaker. Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.</td>
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<td>Breaker Overhaul/Out of Service Diagnostic</td>
<td>Inspect and adjust operating mechanism and assess condition of contacts. Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of contacts. Record and trend results for age exploration.</td>
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<td></td>
<td>Lubricate mechanism. Perform a visual inspection of lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.</td>
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<td></td>
<td>Perform hipot test. Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td>Perform contact resistance test. Perform contact resistance test in conjunction with other tests. If resistance phase differential measurement is greater than 25% or actual resistance greater than specified micro-ohms investigate cause. Record and trend results for age exploration.</td>
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<td>Perform timing test. Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.</td>
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<td>Check manufacturers specs. Check all manufacturers specs as described in the instruction manual.</td>
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<td>Equipment</td>
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<td>Breakers</td>
<td>Distribution</td>
<td>Free Standing SF6</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Check breaker for mechanical integrity.</td>
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<td>Perform visual inspection.</td>
<td>Check breaker and bushings for contamination and damaged insulation.</td>
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<td></td>
<td>Record and verify operations.</td>
<td>Record counter reading. Record number of fault operations. Record relay targets.</td>
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<td>Perform visual inspection.</td>
<td>Check physical grounds on all breakers</td>
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<td>Perform visual inspection.</td>
<td>Check primary drops from disconnects</td>
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<td>Perform visual inspection.</td>
<td>Check all breakers monitor light in cont. house &amp; swgrs</td>
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<td>Record circuit loading.</td>
<td>Record circuit loading for each phase</td>
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<td></td>
<td>Annual In service Diagnostic Maintenance</td>
<td>Perform infrared scan.</td>
<td>See Infrared Inspection Plan and Guidelines for details.</td>
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<td>Functional Test</td>
<td>Trip and close circuit breaker.</td>
<td>Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.</td>
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<td>Breaker Overhaul</td>
<td>Inspect and adjust operating mechanism and assess condition of contacts.</td>
<td>Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of contacts. Record and trend results for age exploration.</td>
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<td></td>
<td>Perform hipot test.</td>
<td>Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td>Perform contact resistance test.</td>
<td>Perform contact resistance test in conjunction with other tests. If resistance phase differential measurement is greater than 25% or actual resistance greater than specified micro-ohms investigate cause. Record and trend results for age exploration.</td>
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<td>Perform timing test.</td>
<td>Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.</td>
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<td>Out of Service Diagnostic Maintenance</td>
<td>Lubricate mechanism.</td>
<td>Perform a visual inspection of lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.</td>
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<td>Perform contact resistance test.</td>
<td>Perform contact resistance test in conjunction with other tests. If the load path resistance phase differential measurement is greater than 25% or actual resistance is greater than specified micro-ohms investigate cause.</td>
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<td>Perform hipot test.</td>
<td>Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td>Perform timing test.</td>
<td>Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.</td>
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<td>Check manufacturers specs</td>
<td>Check all manufacturers specs as described in the instruction manual.</td>
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<td>Equipment</td>
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<td>Proposed Activity Name</td>
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<td></td>
<td>Semi-Annual Inspection</td>
<td>Test cubicle heaters and thermostats. Perform current test on heater system. Record current readings and compare to initial in-service readings. See Infrared Inspection Plan and guidelines for details.</td>
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<td>Annual In service Diagnostic Maintenance</td>
<td>Perform infrared scan. See Infrared Inspection Plan and guidelines for details.</td>
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<td>Functional Test</td>
<td>Trip and close circuit breaker. Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.</td>
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<td>Overhaul/Out of Service Diagnostic Maintenance</td>
<td>Perform Hipot test. Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration. Perform contact resistance test. Perform test in conjunction with maintenance of associated breaker. Perform timing test. Perform test in conjunction with overhaul of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration. Perform visual inspection. Perform visual inspection in conjunction with maintenance of associated breaker. Clean or replace as necessary. Inspect primary disconnects. Perform visual inspection in conjunction with maintenance of associated breaker. Lubricate, adjust or replace as necessary. Lubricate operating mechanism. Perform visual inspection of the mechanism lubrication points, assess the condition of lubricant and re-lubricate. Record and trend results for age exploration.</td>
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<td>Equipment</td>
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<tr>
<td>Breakers</td>
<td>Distribution</td>
<td>Vacuum, SF6</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>As part of station general inspection check breaker for mechanical integrity.</td>
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<td></td>
<td>(Switch Gear)</td>
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<td>Perform visual inspection.</td>
<td>As part of station general inspection, check breaker and bushings for contamination and damaged insulation. Trend the results for age exploration.</td>
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<td>Record and verify operations.</td>
<td>Record counter reading. Record number of fault operations. Record relay targets.</td>
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<td>Perform visual inspection.</td>
<td>Check physical grounds on all breakers.</td>
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<td>Perform visual inspection.</td>
<td>Check primary drops from disconnects.</td>
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<td>Perform visual inspection.</td>
<td>Check all breakers monitor light in cont. house &amp; segs.</td>
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<td>Semi-Annual Inspection</td>
<td>Test mechanism heaters and thermostats.</td>
<td>As part of station general inspection, check breaker cabinet for proper heater operation. Trend the results for age exploration.</td>
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<td>Annual In service</td>
<td>Perform infrared scan.</td>
<td>See Infrared Inspection Plan and Guidelines for details.</td>
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<td>Diagnostic Maintenance</td>
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<td>Functional Test</td>
<td>Trip and close circuit breaker.</td>
<td>Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.</td>
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<td>Out of Service</td>
<td>Lubricate mechanism.</td>
<td>Perform a visual inspection of lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.</td>
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<td>Diagnostic Maintenance</td>
<td>Perform contact resistance test.</td>
<td>Perform contact resistance test in conjunction with other tests. If the load path resistance phase differential measurement is greater than 25% or actual resistance is greater than specified micro-ohms investigate cause</td>
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<td>Overhaul</td>
<td>Perform hipot test.</td>
<td>Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.</td>
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<td></td>
<td>Perform timing test.</td>
<td>Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.</td>
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<td>Check manufacturers specs</td>
<td>Check all manufacturers specs as described in the instruction manual.</td>
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<td>Inspect and adjust operating mechanism and assess condition of contacts.</td>
<td>Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of contacts. Record and trend results for age exploration.</td>
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<td>Equipment</td>
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<tr>
<td>Disconnects</td>
<td>Manual - Single, Ganged</td>
<td>Substation</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Perform visual inspection of disconnects and insulators with associated apparatus</td>
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<td>Annual In service</td>
<td>Perform infrared scan.</td>
<td>Scan disconnects and insulators with associated apparatus. See Infrared Inspection Plan and Guidelines for details.</td>
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<td>Diagnostic Maintenance</td>
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<td>Out of Service Field Maintenance</td>
<td>If switching is required observe operation, report all problems, repair/replace.</td>
<td>Perform visual inspection of the mechanism lubrication points, assess condition of the lubricant and relubricate if necessary. Record trend results for age exploration.</td>
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<tr>
<td>Other (Non Substation)</td>
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<td>Out of Service Field Maintenance</td>
<td>If switching is required observe operation, report all problems, repair/replace.</td>
<td>Perform visual inspection of the mechanism lubrication points, assess condition of the lubricant and relubricate if necessary. Record trend results for age exploration.</td>
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<th>Proposed Activity Name</th>
<th>Task</th>
<th>Task Description</th>
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<tbody>
<tr>
<td>Connectors</td>
<td>MOD/MOS</td>
<td></td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Perform visual inspection of disconnect(s) and insulator(s) with associated apparatus</td>
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<td>Annual In service</td>
<td>Perform infrared scan.</td>
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<td>Diagnostic Maintenance</td>
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<td>Out of Service Field Maintenance</td>
<td>If switching is required observe operation, report all problems, repair/replace.</td>
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<th>Proposed Activity Name</th>
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<tbody>
<tr>
<td>Surge Arresters</td>
<td>All</td>
<td></td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Perform visual inspection of Surge Arresters with associated apparatus</td>
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<td>Annual In service</td>
<td>Perform infrared scan.</td>
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<td>Diagnostic Maintenance</td>
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<td></td>
<td>Out of Service Diagnostic Maintenance</td>
<td>Perform insulation resistance test.</td>
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<th>Equipment</th>
<th>Type</th>
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<th>Task</th>
<th>Task Description</th>
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<tbody>
<tr>
<td>Relays</td>
<td>Electro-mechanical</td>
<td></td>
<td>Bench Test</td>
<td>Bench test relay.</td>
<td>Calibrate to within 50% of the maximum acceptable tolerance if found to be beyond the desired setting. Record as found for age exploration.</td>
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<td>Functional Test</td>
<td>Perform functional test</td>
<td>Move the contacts/spin disk to verify they are free of mechanical binding and verify targets and alarms. Perform this test in conjunction with functional test of associated apparatus.</td>
</tr>
<tr>
<td>Solid State</td>
<td>Bench Test</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Functional Test</td>
<td>Perform functional test</td>
<td>Move the contacts/spin disk to verify they are free of mechanical binding and verify targets and alarms. Perform this test in conjunction with functional test of associated apparatus.</td>
</tr>
<tr>
<td>Microprocessor</td>
<td>Monitor alarms</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>At the occurrence of an alarm investigate the cause.</td>
</tr>
<tr>
<td>Equipment</td>
<td>Type</td>
<td>Make</td>
<td>Proposed Activity Name</td>
<td>Task</td>
<td>Task Description</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>------</td>
<td>------</td>
<td>----------------------------------------</td>
<td>-------------------------------</td>
<td>----------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Station Current Transformer</td>
<td>All</td>
<td></td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Perform visual inspection of current transformers as part of general station inspection.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Inspect Current Transformer</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Annual Ins</td>
<td>Perform infrared scan.</td>
<td>Scan current transformers. See Infrared Inspection Plan and Guidelines for details.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Service Diagnostic Maintenance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Station Potential Voltage...</td>
<td>All</td>
<td></td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Check column for contamination and damaged insulation.</td>
</tr>
<tr>
<td>Transformer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Annual In</td>
<td>Perform visual inspection.</td>
<td>Check PT for oil leaks and gauge for clarity.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Service Diagnostic Maintenance</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Inspect Potential Transformer</td>
<td>Measure secondary voltage of PT</td>
<td>Compare measured readings between phases, if difference &gt; 10% (secondary) investigate the cause. Record and trend results for age exploration.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Perform infrared scan.</td>
<td>Scan potential transformers. See Infrared Inspection Plan and Guidelines for details.</td>
</tr>
<tr>
<td>Metal Clad Bus</td>
<td>All</td>
<td></td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Perform visual inspection enclosed bus with associated apparatus.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Annual In</td>
<td>Test cubicle and bus duct</td>
<td>Perform current test on heater system. Record current readings and compare to initial in-service readings.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Service Diagnostic Maintenance</td>
<td>heaters and thermostats.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Perform infrared scan.</td>
<td>Scan metal clad bus with associated apparatus. See Infrared Inspection Plan and Guidelines for details.</td>
</tr>
<tr>
<td>Air Insulated Bus</td>
<td>All</td>
<td>All</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection.</td>
<td>Perform visual inspection of air insulated bus with associated apparatus.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Annual In</td>
<td>Perform infrared scan.</td>
<td>Scan air insulated bus with associated apparatus. See Infrared Inspection Plan and Guidelines for details.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Service Diagnostic Maintenance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters (Non-Billing)</td>
<td>watt</td>
<td></td>
<td>bench test</td>
<td>Check calibration</td>
<td>compare readings to calibrated standard, adjust to within 2% of standard.</td>
</tr>
<tr>
<td>(watt/vars/duc)</td>
<td>var</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters (Non-Billing)</td>
<td>amm</td>
<td></td>
<td>bench test</td>
<td>Perform visual inspection.</td>
<td>as part of quarterly inspection, compare between phases, if for 12KV &gt; 100 amps between phases or other voltages &gt; 50 amps between phases investigate the cause.</td>
</tr>
<tr>
<td>(Recurrent energy/vars)</td>
<td>hour</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters (Non-Billing)</td>
<td>vol</td>
<td></td>
<td>Annual in</td>
<td>Check calibration</td>
<td>compare readings to calibrated standard, adjust to within 2% of standard.</td>
</tr>
<tr>
<td>(Voltmeters/duc)</td>
<td></td>
<td></td>
<td>Service Diagnostic Maintenance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Equipment</td>
<td>Type</td>
<td>Make</td>
<td>Proposed Activity Name</td>
<td>Task Description</td>
<td></td>
</tr>
<tr>
<td>-------------------</td>
<td>----------</td>
<td>------</td>
<td>------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Voltage Regulators</td>
<td>Distribution</td>
<td>All</td>
<td>Quarterly Inspection</td>
<td>Perform visual inspection. Perform visual inspection of bushings, gaskets, valves, piping and welds for oil leaks, as part of general station inspection. Also check bushings for contamination and damaged insulation.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>Record operations</strong> Check and record counter reading. Record position indicator present position, high and low. <strong>Perform visual inspection. Inspect control cabinet.</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>In service Diagnostic Maintenance</td>
<td><strong>Perform functional test. Prove the operation of the LTC manual/automatic control loop and ensure regulatory voltage tolerances are maintained.</strong> Perform infrared scan. Inspecting oil visual inspection. Sample and visually inspect oil. If excessive moisture is present, investigate source of moisture and perform field dielectric test or send sample to lab for complete oil quality testing. If dielectric strength is &gt; 22KV, recondition or replace oil as required. If oil is excessively dark (light cannot be seen through the oil), send sample to lab for oil quality testing, investigate fault duty on breaker and recondition or replace oil as required. Track and trend results for age exploration.</td>
<td></td>
</tr>
<tr>
<td>Regulator Overhaul</td>
<td></td>
<td></td>
<td>Perform functional test.</td>
<td>Perform a functional test of the regulator control in conjunction with preventative maintenance of associated apparatus. Listen for abnormal operation. Record and trend results.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Perform internal inspection.</td>
<td>Inspect and adjust operating mechanism and assess condition of stationary and arcing contacts. Filter or change oil.</td>
<td></td>
</tr>
<tr>
<td>Reclosers</td>
<td>Distribution</td>
<td>Oil-Hydraulic</td>
<td>Quarterly Inspection</td>
<td>Record and verify operations during inspections. Check and record counter reading, fault operations, targets. <strong>Perform visual inspection. Check for oil leaks and overall condition.</strong> <strong>Perform visual inspection. Check gauge for expected indication and condition.</strong> <strong>Perform infrared scan. See Infrared Inspection Plan and Guidelines for details.</strong> <strong>Trip and close recloser if electronic control.</strong> Reclosers that can be bypassed or transferred internal to the station without dropping load.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Functional Test</td>
<td><strong>Trip and close recloser if electronic control.</strong> Reclosers that have not operated in previous 9 months, and can be bypassed or transferred internal to the station without dropping load.</td>
<td></td>
</tr>
<tr>
<td>Recloser Overhaul</td>
<td></td>
<td></td>
<td>Recloser Overhaul</td>
<td>Perform overhaul, trip test, hi pot, filter oil and adjust per manufacturers specs. Record and trend results for age exploration.</td>
<td></td>
</tr>
<tr>
<td>Reclosers</td>
<td>Distribution</td>
<td>Vacuum</td>
<td>Quarterly Inspection</td>
<td>Record and verify operations during inspections. Check and record counter reading, fault operations, targets. <strong>Perform visual inspection. Check for oil leaks and overall condition.</strong> <strong>Perform visual inspection. Check gauge for expected indication and condition.</strong> <strong>Perform infrared scan. See Infrared Inspection Plan and Guidelines for details.</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>In service Diagnostic Maintenance</td>
<td><strong>Perform infrared scan. See Infrared Inspection Plan and Guidelines for details.</strong> <strong>Trip and close recloser if electronic control.</strong> Reclosers that have not operated in previous 9 months, and can be bypassed or transferred internal to the station without dropping load.</td>
<td></td>
</tr>
<tr>
<td>Recloser Overhaul</td>
<td></td>
<td></td>
<td>Recloser Overhaul</td>
<td>Perform overhaul, trip test, hi pot, filter oil and adjust per manufacturers specs. Record and trend results for age exploration.</td>
<td></td>
</tr>
<tr>
<td>Station Batteries</td>
<td>All</td>
<td>All</td>
<td>Weekly, monthly or quarterly Inspection</td>
<td>Perform visual inspection. Check for battery charger operation, proper voltage, electrolyte level, and condition of connections. **Perform detailed inspection. Test internal and intracell resistances. Check specific gravity, voltage, and temperature of each cell. Perform visual check of electrolyte levels and general conditions. Check main DC bus voltage. Record and trend results. Refer to Battery Maintenance document for further details.</td>
<td></td>
</tr>
</tbody>
</table>
SECTION 1 – PURPOSE

1.1 This policy describes a practical, reliability centered, repair/replacement decision policy for direct buried, URD (underground residential distribution) systems. This decision policy is designed to increase cable replacement activity in response to an increase in the frequency of URD section (span) failure, and to an increase in the frequency of URD circuit outages caused by cable failure.

SECTION 2 – SCOPE

2.1 This policy defines the repair or replacement decision in response to cable failures on direct buried URD systems. Cable failures typically require a local repair unless failure frequency recommends replacement of the section (span), as defined below.

SECTION 3 – FAILURE REPAIR DECISION

3.1 Cable fault location, excavation, and local repair is the “default” response to a cable failure event on a direct buried URD circuit.

Failure repair on a direct buried cable section requires the location, excavation, removal, and repair (splicing) of the faulted area.

Care should be taken when pinpointing the location of the cable fault using high voltage DC testing and capacitive discharge (thumper) equipment to produce an audible confirmation of the fault location. Minimize the potential for further cable damage by reducing “thumper” testing time by approximating the cable fault location using Time Domain Reflectometry (TDR) and then using the lowest discharge voltage necessary to produce an audible “thump.”

SECTION 4 – FAILED SECTION REPLACEMENT DECISION

4.1 Following a cable failure on a direct buried URD cable, schedule replacement of the failed section, in lieu of repair, if any of the following apply,

If the current cable failure event is the:
- 3rd failure in the same section
- 2nd failure in the same section within 1 year of the 1st failure
- 2nd failure on the same URD circuit half-loop within the recent rolling year
- 3rd failure on the same URD circuit half-loop within the recent rolling 2 years.

SECTION 5 - SCHEDULING

5.1 Operations Engineers will prioritize and schedule the required repair or replacement activity as quickly as possible and return the affected loop circuit to its normal configuration to minimize the risk of a lengthy outage during a subsequent failure on the loop.

Replacement may be scheduled in lieu of repair, under certain circumstances, at the Operations Engineers discretion.
SECTION 6 – DECISION SUPPORT

6.1 Operations Engineers will maintain a database to track cables failures, repairs, and replacements.

Operations Engineers will consult the failure database to determine if the criteria is met for section replacement in lieu of local repair.

Operations Engineers will provide monthly reports detailing failure repair and section replacement backlogs and schedules.

The database will contain sufficient cable failure and replacement information to support ongoing failure and replacement budgetary projections and to assist with the development, planning, justification, and prioritization of aging URD cable infrastructure strategies.
SECTION 1 – PURPOSE

1.1 This policy describes operating, maintenance, and inspection requirements for the LG&E-KU low voltage secondary network system in downtown Louisville, Kentucky. Inspection, maintenance, and load monitoring is intended to ensure public safety, minimize the potential for public property damage resulting from delivery system failures, provide safe access and working conditions for operating and maintenance personnel, and to provide reliable electric service.

SECTION 2 – SCOPE

2.1 This policy addresses routine facility inspection, preventive maintenance, and load monitoring requirements applicable to the LG&E-KU low voltage secondary network facilities and equipment. Generally, LG&E-KU facilities will include vaults, manholes, transformers, network protectors, cables, ventilating equipment, and associated hardware.

SECTION 3 – REFERENCES

3.1 Kentucky Administrative Regulations, Title 807 KAR 5:006, Section 25, Inspection of Systems.
3.2 Kentucky Occupational Safety and Health Act (KOSHA).
3.4 EOM&I IS-002, Regulatory Inspection Requirements for the Downtown Louisville Secondary Network.

SECTION 4 – RESPONSIBILITIES

4.1 The Asset Management Electric System Codes and Standards shall have responsibility for the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management and Distribution Operations.

4.2 Auburndale Operations Center shall have responsibility for execution of this policy. Execution of this policy shall include inspecting network vaults and manholes; cleaning and ventilating network vaults; operating trip tests; inspecting, cleaning, and maintaining network protectors; and monitoring network loads.

SECTION 5 – DISCUSSION

5.1 Regulatory Accountability

5.1.1 In accordance with 807 KAR 5:006, Section 25 (4) (b) 3, each utility shall inspect, at intervals not to exceed six months, "underground network transformers and network protectors in vaults located in..."
buildings or under sidewalks, for leaks, condition of case, connections, temperature and overloading”.

SECTION 6 – POLICY

6.1 Inspect Network Vaults and Equipment

6.1.1 Visually inspect the vault enclosure and vault structural equipment including, ceilings, walls, and floors; interior doors; entrance hatches, frames, and ladders; drip pans, shields, and drains; ventilating blowers and duct; drains and dry wells; and cable and equipment mounting hardware. Inspect locking provisions and ensure access security.

6.1.2 Visually inspect vault electrical equipment including, network transformers and protectors; cable bus; transformer, protector, and service conductors; conductor connections; fuse boxes; vault lighting and wiring; and load monitoring equipment. Inspect the transformer case for dielectric coolant leaks. Read, record and reset oil temperature gauges and peaking demand load monitoring equipment.

6.1.3 Vault and vault equipment inspections shall be performed semi-annually.

6.2 Inspect Network Manholes and Equipment

6.2.1 Visually inspect manhole and hardware including, ceilings, walls, and floors; entrance throats; manhole ring and cover; duct openings; dry wells; and equipment mounting hardware.

6.2.2 Visually inspect manhole electrical equipment including, primary, secondary, street lighting, and service cables; communication cables; private and foreign utility conductors; electrolysis cables; grounding and bonding wires; primary cable splices and terminations; secondary and service cable splices, junctions, and terminations; grounding and bonding wire connections; and switching equipment.

6.2.3 Network manhole inspections shall be performed bi-annually. Assign manholes to two annual groups. Inspect each group on alternate calendar years.

6.3 Clean Network Vaults

6.3.1 Remove debris from network vaults and associated equipment to minimize vault fire potential, to minimize equipment surface corrosion and rust, to reduce dust type protector cleaning, and to provide a safe and dry workplace.

6.3.2 Dust off network transformers and network protector cases.

6.3.3 Remove and discard debris from catch pans, ventilating grates, drains and dry wells, and vault floors.

6.3.4 Vault cleaning shall be performed semi-annually.

6.4 Inspect Flood Prone Network Vaults

6.4.1 Inspect vault equipment and pump water from vaults during and/or following heavy rains.

6.4.2 Publish and maintain a list of vaults that retain water during heavy rain.
6.5 Ventilate Network Vaults

6.5.1 Operate and maintain forced air ventilation in summer peaking vaults.

   a. Turn “on” blowers during Spring, prior to summer load increase.
   b. Turn “off” blowers during Fall, following summer load decline.

6.5.2 Clean, lubricate, and winterize blower fans, duct, and vents following summer service.

6.5.3 Publish and maintain a list of vaults that contain ventilating equipment.

6.6 Feeder Trip Test

6.6.1 Network protector trip and close operations shall be tested prior to annual load periods, to verify successful and proper operation.

6.6.2 Test trips shall be performed annually during the Spring season while network loads are at seasonal minimums.

   a. Individual circuits may be exempted from a scheduled test trip if all network protectors operated successfully during the 6 month period immediately preceding the scheduled test trip. The test trip record must reflect the date of the successful operation.

6.6.3 Each network circuit shall be tripped open, one circuit at a time. Load Dispatch will “OPEN” and “CLOSE” the circuit breaker to perform the test.

   a. Following each circuit interruption, verify that the affected protectors "OPENED" upon loss of circuit voltage. Load Dispatch will note that the circuit potential light goes out if all protectors successfully tripped open.
   b. Following circuit restoration, verify that affected network protectors "CLOSED."

6.7 Preventive Maintenance - Inspect, Clean, and Adjust Network Protectors

6.7.1 Inspect, clean, and adjust network protectors (WHILE ENERGIZED) to ensure safe and reliable operation. Refer to detailed, step-by-step instructions for each protector type.

   a. Visually inspect condition of enclosures, mounting hardware, and external terminations.
   b. Visually inspect condition of internal components, including breaker assembly, fuses, links, barriers, relays, control wiring for evidence of broken, loose, and overheated parts.
   c. Clean and dust external covers and internal components.
   d. Lubricate and adjust moving parts.
   e. Clean and lubricate relay mechanism and contacts.

6.7.2 Dust Cover Type and No Cover Type Protectors

   a. Perform routine inspection, cleaning, and adjustments, annually.

6.7.3 Submersible Type Protectors

   a. Perform routine inspection, cleaning, and adjustments, annually.

6.8 Field Testing – Network Protector
6.8.1 Perform electrical and mechanical field operating tests on network protectors and relays immediately following a protector mis-operation or protector maintenance work. Mis-operations include failures to trip or close during normal operation or during Feeder Trip Tests, as defined in Section 6.6.

   a. Refer to detailed, step-by-step instructions provided by the manufacturer for each protector and relay type.
   b. Check electrical and mechanical operation using a network simulation test kit.
   c. Re-calibrate or exchange relay.

6.9 Monitor Network Load

6.9.1 Vault Load Peak Demand

   a. Monitor totalized peaking summer and winter demands on network transformers and protectors.
   b. An AD-6 maximum demand, current type meter and associated current transformers shall be installed in each network vault. The AD-6 meter will be configured to totalize the coincident demand of all transformers in the vault.
   c. Read, reset, and record AD-6 meters during the Spring and Fall seasons to capture the maximum demand during the preceding Winter and Summer seasons, respectively.

6.9.2 Vault Load Indicating Tests and Thermal Imaging Tests

   a. Monitor phase loads and operating temperature on network vault buss, network protector leads, transformer secondary leads, service leads and street main ties to identify imbalance conditions and poor cable connections.
   b. Vault load indicating tests and thermal imaging tests shall be conducted annually during the Summer season.

6.9.3 Secondary and Service Load Indicating Tests

   a. Monitor summer season loads on network secondary street mains and services and vault supply main and services to support load flow analysis on the secondary network grid.
   b. Monitor secondary street main continuity detect open circuit cables.
   c. Summer season load tests shall be conducted bi-annually. Schedule secondary and service load tests on alternating calendar years during June, July, or August.
   d. Street main continuity tests shall be conducted and recorded bi-annually during bi-annual regulatory manhole inspections.

6.10 Network Transformer High Voltage Compartment Insulating Compound Test

   Cable insulating compounds in high voltage cable terminating compartments shall be dielectric tested to detect the presence of moisture on five year intervals.

6.11 Work Schedules

   The activities defined in sections 6.1 through 6.10 above shall be performed coincidentally to optimize technician productivity and to minimize travel time. The requirements of this AOP are sufficient to meet the regulatory inspection requirements as defined in EOM&I-SI-002, "Regulatory Inspection Requirements for Downtown Louisville Secondary Network."

6.12 Network Protector Corrective Maintenance

   Network protector corrective maintenance, including repair, rebuild, and decommissioning shall be individually determined by the network engineer and operating team leader using preventive maintenance histories, operating performance, and test trip results.
SECTION 7 - SAFETY

7.1 All applicable provisions of the Company safety manual shall be observed.

7.2 Cleaning and maintenance of network protectors involve working on energized equipment with exposed and unshielded components.

SECTION 8 – ENVIRONMENTAL

8.1 The downtown network system contains several environmentally regulated materials and compounds.

   8.1.1 Network protectors manufactured prior to 1990 utilized asbestos-containing materials in arc-extinguishing assemblies, non-metallic structural members, and insulating barrier boards.

   8.1.2 Network cable bus conductors and connections manufactured and installed prior to the early 1980’s utilize asbestos fire proofing tapes.

   8.1.3 Network transformers contain insulating fluids, such as, mineral oil, high fire point mineral oil, silicon fluid, and various cable compounds. Network transformers may contain traces of Polychlorinated Biphenols (PCB).

   8.1.4 Paper Insulated Lead Covered (PILC) primary and secondary cables and associated cable splices are insulated with medium and high viscosity oils and petroleum based compounds contained within an overall lead jacket.

8.2 Special measures are required when disturbing and/or disposing asbestos-containing materials. Contact the Environmental Affairs Department prior to handling and disposing of asbestos materials.

8.3 Fluid release from network transformers in network vaults shall be immediately contained and reported promptly to the Transformer Services Department for cleanup.

   8.3.1 Transformers labeled as containing PCB fluids or not having a label specifically stating that the fluid is non-PCB, shall be handled as if containing PCB fluids.

   8.3.2 Fluid releases and disposal shall be reported to the Environmental Affairs Department.

8.4 Materials containing lead may require special disposal considerations. Contact the Environmental Affairs for disposal recommendations and assistance.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 Employees performing cleaning, inspection, testing, and rebuilding must be qualified by training and/or experience.

SECTION 10 – EQUIPMENT

10.1 Network testing equipment and recording instruments

   10.1.1 Network protector electrical test kit.
   10.1.2 Electronic relay interface devices.
   10.1.3 Voltmeter.
   10.1.4 Ammeter.
   10.1.5 Recording voltmeter.
   10.1.6 Recording ammeters.
   10.1.7 Thermometer (ambient air).
10.1.8 Thermal imaging camera.

SECTION 11 – RECORD KEEPING

11.1 Vault, manhole, and miscellaneous equipment inspection and maintenance records provided in Sections 6.1 through 6.5 shall be retained by the Auburndale Operations Center for a minimum of five years.

11.2 Network protector trip tests, preventive maintenance, field tests provided in Section 6.6 through 6.8 and primary termination compound dielectric tests provided in Section 6.10 shall be retained by the Auburndale Operations Center for the life of the equipment asset.

11.3 Load monitoring records provided under Section 6.9 shall be retained by Asset Management - System Analysis and Planning group.
SECTION 1 – PURPOSE

This policy documents the inspection requirements for electric distribution substations, distribution lines and equipment and meters at Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU). The inspection program is intended to identify, where possible, problems or potential problems that could have an adverse effect on safety, customer service and/or the orderly and efficient operation of the electric distribution system. It is structured to assure that assets are properly inspected, apparent deficiencies identified and documented, and records retained to ensure compliance with requirements of the Kentucky Public Service Commission (KY PSC) and company procedures. This document is to be filed with the KY PSC per regulation KRS Chapter 278 and 807 KAR Chapter 5 Section 26 - Inspection of Systems.

SECTION 2 – SCOPE

2.1 This policy details the requirements for a periodic, ground based inspection program for electric distribution substations and electric distribution facilities operating at voltages less than 69,000 volts up to the point of service, including overhead and underground electric lines, equipment, utility owned (leased) lighting and meters. It does not cover the inspection of underground network transformers and network protectors in vaults addressed in EOM&I-SI-002: Regulatory Inspection Downtown Louisville Secondary Network Vaults, current revision.

2.2 The objectives of the distribution system inspection program are to:

2.2.1 Enhance public safety and the safety of LG&E and KU employees and contractors by periodically inspecting all distribution substations, electric lines, structures and equipment for recognizable damage, defects and/or unsafe conditions.

2.2.2 Improve system reliability, where possible, by identifying defective and/or damaged structures or equipment and other operating conditions which could result in outages or failures.

2.2.3 Provide documentation of inspections, deficiencies found and corrective actions taken.

2.2.4 Maintain compliance with the KY PSC Regulations and the National Electrical Safety Code (NESC) regarding distribution inspections.
SECTION 3 – REFERENCES

3.1 Kentucky Revised Statutes Chapter 278
3.2 Kentucky Administrative Regulations, Title 807 KAR 5:006, Section 26, Inspection of Systems.
3.3 Kentucky Occupational Safety and Health Act (KOSHA).

SECTION 4 – RESPONSIBILITIES

4.1 Asset Management’s Electric System Codes and Standards section shall have responsibility for revising and communicating the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management, Distribution Operations and Metering.

4.2 At LG&E, regulatory inspections for overhead and underground lines and associated equipment operating at less than 69,000 volts and the associated record keeping is centralized at Auburndale Operations Center in Louisville, Kentucky.

4.3 At KU, regulatory inspections for overhead and underground lines and associated equipment operating at less than 69,000 volts and the associated record keeping are performed by the individual operations centers. Specifically, these centers are located in Lexington, Richmond, Danville, Shelbyville, Elizabethtown, Maysville, Pineville, London and Earlington.

4.4 At LG&E and KU, regulatory inspections for meters and associated record keeping are performed by Meter Reading and stored electronically in the system(s) of record.

4.5 Regulatory inspections for distribution substations and the associated record keeping are performed by the individual Substation centers. Specifically, these centers are located in Louisville, Lexington, Danville, Pineville, and Earlington.

4.6 Records shall be stored electronically and/or filed in the appropriate substation, metering or operations center offices and kept for the time prescribed in Section 11 – Record Keeping. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

SECTION 5 – DISCUSSION

5.1 This policy and the KYPSC regulations impose minimum standards for frequency, content of inspections and record requirements. Nothing in this document shall be construed as limiting more frequent and/or more rigorous inspections and/or more stringent record requirements at the discretion of the individual operations center.

5.2 Inspection methods, timing of inspections and labor resource (utility personnel/contractor) utilized to complete regulatory inspections may vary by center provided they meet the minimum requirements contained in this document.

SECTION 6 – POLICY

6.1 Inspection Frequency for Substations, Distribution Lines, Equipment, and Meters.

The requirements of regulation KY KYPSC 807 KAR 5:006 Section 26 - Inspection of Systems impose the following minimum requirements for inspection frequency for substations, distribution lines, equipment, and meters.
6.1.1 At intervals not to exceed two years:
   a) Electric lines, equipment, and meters operating at a voltage less than 69,000 volts.

6.1.2 At intervals not to exceed one year:
   a) Distribution substations with primary voltage of less than 69,000 volts.

6.1.3 At intervals not to exceed six months:
   a) Distribution substations with primary voltage 69,000 volts or greater.

6.1.4 Upon receipt of any report of a potentially hazardous condition all portions of the system which are the subject of the report shall be inspected as soon as practicable.

6.2 Intent of Inspections

6.2.1 Inspections will be completed by utility personnel or contractors qualified to perform field inspections.

6.2.2 The intent of the regulatory inspection is not to perform a detailed technical assessment of every line or structure or to open and inspect every piece of equipment unless a problem is otherwise apparent. The intent is to visually inspect the system looking for apparent unsafe conditions, while identifying, where possible, damaged and/or defective equipment and other operating conditions that may affect system reliability or safety. A listing of items commonly checked during inspections can be found in the Appendix of this document.

6.2.3 Distribution Lines and Equipment

6.2.3.1 The inspection of overhead and underground lines and equipment will consist of a ground (foot, vehicle) based visual inspection. The most effective method to achieve this requirement for each portion of line will be determined by the operating center based on the characteristics of the line being inspected. Aerial inspections shall not be used as the basis for compliance.

6.2.3.2 Distribution lines and equipment placed on foreign owned structures will be inspected to the same extent as facilities on the utility’s own structures. It is not the responsibility of the utility to inspect foreign owned structures, lines or equipment. However, defects or structural deficiencies with foreign owned structures and attachments identified during routine inspections will be reported to the facility owner whenever such deficiencies could have a detrimental impact on safety or operation of the utility’s lines and equipment. Any such deficiencies shall be documented in the same manner as deficiencies on the utility’s own structures and tracked in the same manner until all deficiencies have been corrected.

6.2.3.3 It is not the responsibility of the utility to inspect foreign owned lines and equipment located on utility owned structures. However, such deficiencies identified during routine inspections will be reported to the facility owner whenever such deficiencies could have a detrimental impact on safety or operation of the utility’s lines and equipment. Any such deficiencies shall be documented in the same manner as deficiencies on the utility’s structures and tracked in the same manner until all deficiencies have been corrected.

6.2.3.4 Damage or unsafe conditions on customer-owned wiring or equipment at the utility/customer interface point identified during the course of normal utility inspections shall be documented and reported to the customer, and where necessary the appropriate Authority Having Jurisdiction (AHJ).

6.2.3.5 Utility owned (leased) lighting equipment mounted on overhead distribution line structures and underground fed leased lighting structures will be inspected as part of routine system inspections.
6.2.4 Electric Meters.

The inspection of manually-read meters and walk-by AMR meters will consist of a visual inspection by meter readers during the course of routine meter reading.

6.2.5 Distribution Substations.

The inspection of substations will consist primarily of a field visit to each substation site and a visual inspection of the substation facilities and equipment.

6.3 Patrol along Roads, Cross Country or in Easements

6.3.1 Visual inspections of distribution lines and equipment may be accomplished by patrolling lines from vehicles when distribution facilities are located adjacent to and in reasonable proximity to roadways. Patrolling lines from vehicles is also permitted in off road easements where vehicle access is available. Facilities located in easements on private property where vehicle access is either not available or not practical due to the nature of the line, must be inspected on foot.

6.3.2 Every reasonable attempt should be made to inspect each structure or piece of equipment from its immediate vicinity. If inaccessible, inspection with binoculars is permitted. If access cannot be gained to at least perform a visual inspection, the area or line must be noted on the inspection print and provisions made to inspect at another time. At a minimum, the intent is to visually inspect every structure, line, and piece of equipment each inspection cycle.

SECTION 7 - SAFETY

7.1 Personnel performing the duties related to system inspection shall perform the necessary tasks in a safe manner and in compliance with company and departmental Safety Manuals, procedures and policies using the required Personal Protective Equipment (PPE). Special attention will be directed to the hazards related to terrain, insects, snakes, other animals, and plants as well as vehicular hazards.

SECTION 8 – ENVIRONMENTAL

8.1 Oil filled equipment found to be passively leaking will be noted as part of the inspection process. Equipment found to be actively leaking requires immediate notification of the appropriate responsible department(s) so that compliance with utility oil spill response procedures can be assured.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 All inspectors must be knowledgeable of company Safety Manual, safety policies and procedures and have a working knowledge of the NESC as it applies to the facilities being inspected. Distribution line inspectors shall have complete familiarity with the construction and operation of distribution lines, equipment and structures as well as a working knowledge of company construction standards. Meter readers shall have complete familiarity and working knowledge of meter reading and meter inspection requirements. Substation inspectors shall have complete familiarity and working knowledge of substation facilities and equipment.

SECTION 10 – EQUIPMENT

10.1 Inspectors shall be equipped with and qualified in the use of all personal protective equipment (PPE) appropriate for the work and facilities being inspected.

10.2 Inspectors shall carry a cellular phone and/or a company radio at all times while performing inspection work suitable for contacting the appropriate emergency response personnel in the event of an emergency or appropriate company personnel in the event an active oil leak or potentially dangerous condition is found during the course of inspection.
SECTION 11 – RECORD KEEPING

11.1 Records of Inspection – Distribution Lines and Equipment

11.1.1 Distribution line inspections must be performed from inspection records which identify every primary line segment, such as a circuit map, facility map, or electronic mobile mapping technology. Secondary voltage lines and services and leased lighting facilities need not be shown on these records. However, they must be inspected.

11.1.2 Each inspection record must contain the inspector’s name and the completion date of the inspection, if inspected in whole on the completion date. If multiple days are required to complete the inspection, each portion inspected will be noted with each line segment being coded by respective date inspected and inspector’s name. In addition, an overall completion date for the entire record is required when the inspection is complete.

11.1.3 Deficiencies found during inspections are to be identified by a unique number so that a cross-reference can be established between the inspection record and the deficiency repair order or work request. These records are the tangible basis from which the KYPSC will audit. Keeping records in this manner allows the KYPSC to verify that a facility was inspected, to relate the inspection to deficiencies found, to track the deficiency to a repair order, work request, database or work management system entry and to determine the disposition of work to correct the deficiency.

11.1.4 The inspection and deficiency records will be filed in the appropriate operations center offices and kept for six years. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

11.2 Records of Inspection – Meter

11.2.1 Meter inspections will be performed using electronic devices that allow for identification of each meter, location, date and time, inspector’s name, and deficiency if applicable.

11.2.2 The inspection and deficiency records will be stored electronically or filed in the appropriate metering offices and kept for a minimum of six years. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

11.3 Records of Inspection – Substations

11.3.1 Substation inspections will document substation name, location, date, inspector’s name, and deficiency if applicable.

11.3.2 The inspection and deficiency records shall be filed in the appropriate substation center offices and kept for four years. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

11.4 Documentation and Tracking of Deficiencies Found – Distribution Lines

11.4.1 When the inspector identifies a deficiency, a sequential or otherwise unique number is to be marked on the inspection record for that location. All pertinent information about the deficiency is to be recorded on a deficiency report form which contains the corresponding number placed on the inspection record, including a description of the problem, the exact location (house number or distance from a known highway intersection, etc.), the pole or coordinate number (if available) and any other pertinent information.

11.4.2 Where deficiency form is to also serve as the final repair record, information must be added to the deficiency form once work is completed which at a minimum includes, the completion date, repair crew information and a description of the corrective actions taken to address the deficiency. Upon completion of the work, the original deficiency form must be filed with the inspection record or retained in another manner such that the status and/or disposition of the corrective work can be tracked from the original inspection record.
11.4.3 Where the deficiency form information is to be transferred to a different work request document, work management system or database to manage the deficiency correction, all appropriate information from the deficiency form is transferred to the work request document or entered into the electronic record. Unless stored in a database that can be queried for the original deficiency form number recorded on the inspection record, each form or data entry must also have a unique identifier assigned that can be tracked to the original deficiency form number. The new work request or data tracking number will be recorded on the original inspection print and/or recorded on the deficiency form where the deficiency form is to be retained separate of the inspection record. At all times continuity must be maintained between the inspection record, deficiency form and any other form or electronic entry used to manage corrective work. Upon completion of work to correct the deficiency, the form or record must be updated with information which at a minimum includes, the completion date, repair crew information and a description of the corrective actions taken to address the deficiency.

11.4.4 When a defect, deficiency, or other condition is found that poses an imminent hazard to safety or customer service, the inspector must immediately notify (by phone or radio) the appropriate department for corrective action. If the condition represents a present safety hazard to customers or the public in general, such as a live wire down, the inspector must guard the area until maintenance crews arrive to make the area safe.

11.5 Documentation and Tracking of Deficiencies Found – Electric Meter

11.5.1 Meter deficiencies found will be recorded and identified to the specific meter with a repair order, description of the deficiency, location of meter, and any other pertinent information. The completion date, repair crew information, and appropriate remarks will be added once the work is complete. All records will be maintained by Meter Reading and stored electronically in the system(s) of record.

11.6 Documentation and Tracking of Deficiencies Found - Substations

11.6.1 Substation deficiencies found will be recorded and identified to the specific substation with a corrective work order, description of the deficiency, location, and any other pertinent information. The completion date, repair crew information, and appropriate remarks will be added once the work is complete. All records will be maintained electronically in the substation work management system.
Appendix – Guidelines for Inspection

A.1.0 Guidelines for Overhead Inspection (conditions to be reported)

A.1.1 Structures

a) All Supporting Structures – General
- Excessive lean or bowing
- External damage (vehicles, vandals, etc.)
- Insufficient clearance from curbs, roads, etc.
- Physical damage protection/marking (if required)
- Climbing hazards (including excessive vines and vegetation)
- Unauthorized foreign attachments (basketball goals, customer wiring/lighting, security cameras, etc.)
- Presence of any permanent climbing steps or other platforms providing climbing access (at least eight feet above ground level)
- Equipment and equipment supports are not readily climbable (hardware does not facilitate climbing – eight feet between footholds and handholds starting at not more than six feet above ground)
- Presence of fences, trees, sheds that would facilitate climbing by members of the public or encourage climbing by children
- Insufficient or improper grounding
- Lack of foundation integrity
- Proper signage when required
- Objectionable graffiti

b) Wood Poles
- Externally visible physical damage (external decay, woodpecker holes, excessive checking, damage by fire, vehicle contact, etc.)
- Ground line deficiencies.
  Wood poles with obvious ground line deficiencies must be sounded from ground line to six feet. If significant external decay is suspected at or just below the ground line, it may become necessary to remove soil from around the base of the pole, where practical, to determine the extent of decay. Poles with decay, infestation, or cracks, sufficient to jeopardize safety or service restoration shall be turned in for replacement or repair. If a pole is sufficiently defective to be a safety hazard to a person climbing the pole or to the public in general, a danger pole tag must be applied to the pole and special attention given to replacing the pole. In areas where poles appear solid, a reasonable attempt to sound a representative sample (approximately 10%) should be made. Exception: Wood pole structures supporting lines crossing limited access highways or railroads must be sounded each inspection cycle.

c) Steel Poles, Guy Beams and Lattice Towers
- Excessive corrosion or rust affecting structural integrity
- Missing, loose, damaged foundation bolts and nuts
- Loose or missing bracing

d) Concrete Poles
- Spalling
- Excessive cracking, voids, holes, etc.

A.1.2 Overhead Equipment
- Broken or damaged
- Oil leaks
- Structurally damaging rust (does not include minor surface rusting)
- Bulged
- Overheating (discolored terminals or melted insulation)
- Flashed or broken bushings or terminals
Not bolted securely to structure
Excessive lean
Blown fuses
Blown lightning arresters
Cutouts and switches not properly terminated and fully closed
Ground mounted equipment controls not locked and otherwise secure

A.1.3 Conductor Supports
a) Crossarms
- Broken, split, twisted, burned, or rotten
- If steel, excessive (structural) corrosion
- Not securely bolted to structure
- Braces not installed and in good working order

b) Miscellaneous Support Brackets, and Hardware
- Flashed or broken
- Broken spacer cable brackets or bands
- Not securely bolted to structure
- Loose or missing hardware

c) Insulators
- Cracks, chips and signs of flashing/tracking
- Excessive dirt, soot or other possible contamination
- Improper insulator attachment (suspension insulators are properly attached to pole, crossarm or other support, pin insulators are properly seated on pin or secured to support arm, pole, etc.)
- Conductor improperly secured to insulators (conductor floating)

A.1.4 Anchors and Guys
- Inadequate for loads or slack guying
- Improper insulation (insulate or grounded)
- Improper positioned guy insulators (insulated guys)
- Guy guards not installed (one per anchor)
- Anchor rod/eyes and guy-wire not sufficiently above grade to minimize the possibility of guy-wire or guy grip deterioration
- Anchor pulling out (excessive rod length)
- Guy wire strands, grips, and/or automatic guy deadends damaged, corroded, or broken
- Improperly insulated, grounded or guarded guys
- Guying hardware (guy hooks and eyebolt assemblies) are deteriorated or improperly secured
- Insufficient clearances (distance between guy wires and curbs, sidewalks, paths, roads, etc. is not satisfactory)
- Push poles (improperly connected and structurally sound)
- Third party guying or lack of proper guying (obvious problems affecting pole loading/leaning/buckling)

A.1.5 Primary and Secondary Conductors and Conductor Hardware
- Improper clearances (at structure, throughout span, adjacent to other structures, or over ground)
- Defective conductors, splices, or connections (burns, broken strands or evidence of overloading such as discoloration or melted insulation)
- Improperly secured to insulators or deadend assemblies
- Foreign objects (trees, balloons, shoes, etc.)
- Vegetation (growing into or rubbing against conductors)
- Illegal services or unmetered load
- De-energized and/or abandoned lines not properly grounded
- Apparent easement violations (pools, buildings, private structures, etc.)

A.1.6 Services
- Low over roads, driveways or parking areas
- Improperly attached at house and pole
- Improper clearance over deck, garages and other structures
Vegetation (limbs not clear from laying or rubbing on service to cause service integrity problems)
Conduit damage (Overhead or UG)

A.1.7 Overhead Lighting
- Broken or loose mounting arms or fixtures
- Damaged or broken lighting fixtures

A.2.0 Guidelines for Underground Inspection (conditions to be reported)

A.2.1 Area around Equipment
- Improper clearances (to buildings, roads, fences, etc.)
- Traffic barriers (if required) not in place or not in satisfactory condition
- Vegetation (not trimmed to permit opening of cabinet and provide room for switching / maintenance)
- Dumping/Storage (materials or debris stored in front of or against the equipment)
- Ground erosion exposing energized cables
- Fences around open air installation on ground not secure, locked, and properly signed
- Danger and warning signs not properly applied
- Penta-head bolt not in subgrade grating

A.2.2 Pad/Foundation
- Not properly leveled
- Ground erosion compromising pad stability
- Damaged (cracked, broken, etc.)

A.2.3 Cabinet/Enclosure/Tank
- Improper alignment on pad (gaps between cabinet and pad)
- Holes (screw holes, bolt holes, rust holes, etc.)
- Mechanical damage due to rust
- Leaks or swollen areas
- Door/hood hinges damaged
- Cabinet doors/hood not properly aligned (no excessive gaps or spaces to permit access to the inside with wires, rods, etc.)
- Cabinet not properly secured (pentahead bolt and company lock not in place)
- Proper signage not applied ("Warning" meeting specifications of ANSI Z535, and "No Obstructions/Planting" signs not in place)
- Paint is not in satisfactory condition to prevent excessive corrosion
- Objectionable graffiti
- Lifting hardware has been removed
- Signs of excessive heating

A.2.4 Miscellaneous
- Loose or missing lids or covers (splice box lid, pedestal covers, etc.)
- Terminations show signs of tracking, excessive heating or otherwise damaged.
- Secondary buswork (open air) not properly insulated with no obvious signs of excessive heating

A.2.5 Underground Fed Lighting Poles and Fixtures
- Physical damage to pole
- Severely leaning poles
- Missing, loose, damaged foundation bolts and nuts
- Missing hand hole covers/exposed wiring
- Unauthorized attachments
- Damaged or missing fixtures, globes, etc.

A.3.0 Meters (conditions to be reported)
✓ Properly secured (missing seal, lock, cover)
✓ Broken glass
✓ Damaged meter, meter base, metering cabinets
✓ Vegetation (obstructions)

A.4.0 Substations (specific conditions on the following, including all status indicators, gauges, and metering if applicable, will be checked and deficiencies reported)

✓ Drive and Approach
✓ Fence and Gates, Substation Security
✓ Warning Signs, Danger Signs and Barriers
✓ Structures
✓ Annunciator Systems
✓ Disconnects and Motor Operated Disconnects
✓ Station Grounds
✓ Transformers, Tap Changers and Regulators
✓ Circuit Breakers and Reclosers
✓ Capacitor and Capacitor Protective and Switching Equipment
✓ Control House
✓ Switchgear
✓ Station Yard
✓ Metering
✓ Spill Prevention Control and Counter Measure
✓ Fire Protection System
SECTION 1 – PURPOSE

1.1 This policy describes inspection requirements for the LG&E-KU low voltage secondary network distribution system in downtown Louisville, Kentucky mandated by the Kentucky Public Service Commission. Regulatory inspections are intended to assure safe and adequate operation of its facilities.

SECTION 2 – SCOPE

2.1 This policy defines the regulatory inspection of underground network transformers and network protectors in vaults located within buildings and under sidewalks of the secondary network distribution system.

SECTION 3 – REFERENCES

3.1 Kentucky Administrative Regulations, Title 807 KAR 5:006, Section 25, Inspection of Systems.

3.2 Kentucky Occupational Safety and Health Act (KOSHA).


SECTION 4 – RESPONSIBILITIES

4.1 The Asset Management Electric System Codes and Standards section shall have responsibility for the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management and Distribution Operations.

4.2 Auburndale Service Center shall have the responsibility for the execution of this policy. Execution of this policy shall include regulatory vault and vault equipment inspection and load monitoring.

SECTION 5 – DISCUSSION

5.1 Regulatory Accountability

5.1.1 In accordance with 807 KAR 5:006, Section 25 (4) (b) 3, each utility shall inspect, at intervals not to exceed six months, “underground network transformers and network protectors in vaults located in buildings or under sidewalks, for leaks, condition of case, connections, temperature and overloading.”
SECTION 6 – POLICY

6.1 Inspect Network Vault and Equipment

6.1.1 Visually inspect vault sidewalk surface areas for pedestrian safety including access and ventilation gratings and access hatchways. Inspect locking provisions and insure access security.

6.1.2 Visually inspect vault electrical equipment including network transformers and protectors; cable bus; transformer, protector, and service conductors; conductor connections; and load monitoring equipment. Inspect the transformer case for dielectric coolant leaks. Read, record and reset oil temperature gauges and peaking demand load monitoring equipment.

6.1.3 Vault and vault equipment inspections shall be performed semi-annually.

6.2 Monitor Network Loads

6.2.1 Vault Load Peak Demand

a. Monitor totalized peaking summer and winter demands on network transformers and protectors.

b. An AD-6 maximum demand, current type meter and associated current transformers shall be installed in each network vault. The AD-6 meter will be configured to totalize the coincident demand of all transformers in the vault.

c. Read, reset, and record AD-6 meters during the Spring and Fall seasons to capture the maximum demand during the preceding Winter and Summer seasons, respectively.

SECTION 7 - SAFETY

7.1 All applicable provisions of the Company safety manual shall be observed.

7.2 Inspecting vault electrical equipment involves working around energized equipment with exposed and unshielded components.

SECTION 8 – ENVIRONMENTAL

8.1 The downtown network system contains several environmentally regulated materials and compounds.

8.1.1 Network protectors manufactured prior to 1990 utilized asbestos-containing materials in arc-extinguishing assemblies, non-metallic structural members, and insulating barrier boards.

8.1.2 Network cable bus conductors and connections manufactured and installed prior to the early -1980’s utilize asbestos fire proofing tapes.
8.1.3 Network transformers contain insulating fluids, such as, mineral oil, high fire point mineral oil, silicon fluid, and various cable compounds. Network transformers may contain traces of Polychlorinated Biphenols (PCB).

8.1.4 Paper Insulated Lead Covered (PILC) primary and secondary cables and associated cable splices are insulated with medium and high viscosity oils and petroleum based compounds contained within an overall lead jacket.
8.2 Fluid release from network transformers in vaults shall be immediately contained and reported promptly to the Transformer Services Department for cleanup.

8.2.1 Transformers labeled as containing PCB fluids or not having a label specifically stating that the fluid is non-PCB, shall be handled as if containing PCB fluids.

8.2.2 Fluid releases and disposal shall be reported to the Environmental Affairs Department.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 Employees performing inspections and load tests must be qualified by training and/or experience.

SECTION 10 – EQUIPMENT

10.1 Network testing equipment and recording instruments required for inspection and load monitoring.

10.1.1 Ammeter.
10.1.2 Thermometer (ambient air).
10.1.3 Temperature tester.

SECTION 11 – RECORD KEEPING

11.1 Records shall be kept to document inspections, deficiencies, and corrective action.

11.2 Maintenance records shall be retained by Distribution Operations Center.

11.3 Load monitoring records shall be provided to and retained by Asset Management’s System Analysis and Planning group.

11.4 Inspection and maintenance resulting from activities in section 6.1 and 6.2 shall be retained for a minimum of five years and be available for inspection by KyPSC.

11.5 Equipment maintenance records shall be retained for the life of the equipment asset.
SECTION 1 – PURPOSE

1.1 This procedure describes the requirements for voltage surveys and records on LG&E Energy Corp.’s facilities.

SECTION 2 – SCOPE

2.1 This procedure is applicable to all LG&E Energy Corp.’s facilities subject to voltage survey, per Kentucky Administrative Regulations. Generally, LG&E Energy Corp.’s facilities shall include all substations, line regulators, and distribution circuits.

SECTION 3 – REFERENCES

3.1 Kentucky Administrative Regulations, Title 807 KAR 5:041, Section 7, Voltage Surveys and Records.

3.2 Kentucky Administrative Regulations, Title 807 KAR 5:041, Section 13, Testing Equipment and Standards.


SECTION 4 – RESPONSIBILITIES

4.1 The Asset Management’s Operating Policy and Standards section shall have responsibility for revising the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management and Distribution Operations.

4.2 The Substation Construction and Maintenance and/or Auburndale Trouble & Power Quality departments shall be responsible for conducting and coordinating the voltage survey at Substations and line regulators.

4.3 The Asset Management’s System Analysis and Planning section shall have the responsibility for determining the number and location of the representative points that are surveyed for low voltage. If engineering judgment is used rather than network analysis software, the Operating Centers shall have responsibility for determining the number and locations of the representative points.

4.4 The Auburndale Trouble & Power Quality department (LG&E) or Operations Centers (KU) shall be responsible for conducting and coordinating the voltage survey for representative points; i.e., low voltage.

[Signatures]

John K. Wolfe
Dir., Distribution Operations

Butch Cockrell
Dir., Distribution Operations

Yasmin Maynard
Dir., Distribution Operations

Dir., Asset Management

Kerry Thomas
Dir., Distribution Operations

Patty Wolfe
Manager, Operating Policy
4.5 The Auburndale Trouble & Power Quality department, Operating Centers, or Trouble department (Lexington only) shall be responsible for conducting voltage surveys for high voltage.

SECTION 5 –DISCUSSION

5.1 Regulatory Accountability

In accordance with 807 KAR 5:041, Section 7, “each utility shall make a sufficient number of voltage surveys to indicate the service furnished from each center of distribution”. In addition, each utility shall keep at least one portable indicating voltmeter or recording or graphic voltmeter in continuous service at some representative point on its system. Finally, records of voltage surveys taken within the last three years shall be available for inspection by the utility’s customers and Public Service Commission’s staff.

In accordance with 807 KAR 5:041, Section 13 (9), “all working indicating instruments shall be checked against master indicating instruments at least once in each six (6) months”. In addition, “a calibration record shall be maintained for each instrument showing all pertinent data and name of person performing tests”.

SECTION 6 – POLICY

6.1 Voltage Surveys at Centers of Distribution

6.1.1 Definitions

a. Centers of Distribution - All substations and line regulators located on LG&E Energy Corp.’s system.
b. SCADA Equipped substations – Substations that have SCADA functionality.
c. Non-SCADA Equipped substations – Substations that do not have SCADA functionality.
d. Voltage survey – A recording of voltage that is conducted for a specific period of time.
e. Indicating voltages – An instantaneous voltage reading.

6.1.2 Recording Voltage

a. Voltage at SCADA equipped substations shall be recorded using SCADA equipment.
   1. Voltage information shall be stored in the SCADA database.
   2. Voltage information shall be available from either the system or database administrator.
b. Voltage at non-SCADA equipped substations and line regulators shall be recorded using handheld voltmeters.

6.1.3 Monitoring Interval

a. At SCADA equipped substations, voltage shall be continuously monitored. In addition, alarms shall be generated if the voltage is found to be outside of the acceptable range.
b. At non-SCADA equipped substations, voltage surveys shall consist of an indicating test on potential signal used to regulate bus voltage. These indicating tests shall be conducted as a part of routine substation inspections.
c. At line regulators, voltage surveys shall consist of an indicating test and be conducted on an annual basis.

6.1.4 Conducting and Coordination of Voltage Survey

a. For substations, the Substation Construction and Maintenance and Auburndale Trouble & Power Quality departments shall be responsible for conducting and coordinating the voltage survey.
b. For line regulators, the Substation Construction and Maintenance or Auburndale Trouble & Power Quality departments shall be responsible for conducting and coordinating the voltage survey.

1. For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall be responsible for conducting and coordinating the voltage survey.
2. For Kentucky Utilities, the Substation Construction and Maintenance department shall be responsible for conducting and coordinating the voltage survey.

6.2 Voltage Surveys at Representative Points

6.2.1 Definitions

a. Representative points – Circuit points on LG&E Energy Corp.’s system that are suspected of having low voltages.
b. Voltage survey – A continuous recording of voltage that is conducted for a specific period of time

6.2.2 Recording Voltage

a. Voltage at representative points shall be recorded using portable recording voltmeters.
b. For low voltage, the number and location of the representative points shall be determined by the Asset Management’s System Analysis and Planning section and/or Operations Center. This determination shall be based upon network analysis tools and/or engineering judgment.

1. If network analysis tools are used, the System Analysis and Planning section shall be responsible for determining the number and location of the representative points.
2. If engineering judgment is used, the Operations Centers shall be responsible for determining the number and location of the representative points. When engineering judgment is used, the following minimum information shall be recorded: 1) Survey Year, 2) Type of Survey, i.e., Representative Point, 3) Operations Center, 4) Substation, 5) Circuit number, 6) Date Reviewed, 7) Name of the person who performed the review, 8) Whether a survey is required, and 9) Reason for not requiring a survey. Shown below is an example spreadsheet that contains the minimum required information.

<table>
<thead>
<tr>
<th>Substation</th>
<th>Circuit No.</th>
<th>Date Reviewed</th>
<th>Reviewed By</th>
<th>Survey Required</th>
<th>Reason (if survey is not required)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Example No. 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ashby Trail No. 1</td>
<td>1201</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Circuit not worst case on substation</td>
</tr>
<tr>
<td></td>
<td>1202</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Circuit not worst case on substation</td>
</tr>
<tr>
<td></td>
<td>1203</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Circuit not worst case on substation</td>
</tr>
<tr>
<td></td>
<td>1204</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Worst case on substation, analysis shows no low voltage,</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>analysis on file</td>
</tr>
<tr>
<td>Example No. 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ashby Trail No. 2</td>
<td>1205</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Circuit not worst case on substation</td>
</tr>
<tr>
<td></td>
<td>1206</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>Yes</td>
<td>Survey results and analysis on file</td>
</tr>
<tr>
<td></td>
<td>1207</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Analysis showed no low voltage</td>
</tr>
<tr>
<td>Example No. 3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bishop Trail No. 1</td>
<td>1217</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Circuit not worst case on substation</td>
</tr>
<tr>
<td></td>
<td>1218</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Line regulators on circuit, analysis shows no low voltage</td>
</tr>
<tr>
<td></td>
<td>1219</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Worst case on substation, analysis shows no low voltage,</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>analysis on file</td>
</tr>
<tr>
<td></td>
<td>1220</td>
<td>6/28/2001</td>
<td>P. Just</td>
<td>No</td>
<td>Circuit not worst case on substation</td>
</tr>
</tbody>
</table>

3. Voltage surveys shall be conducted during heavy loading conditions.

c. For high voltage, voltage surveys shall be conducted on an as needed basis as determined by customer complaints. The duration of the voltage survey shall be determined by the Auburndale Trouble & Power Quality department, Operating Centers, or Trouble department (Lexington only).
6.2.3 Monitoring Interval

Typically, voltage surveys shall be conducted for seven (7) days.

6.2.4 Conducting and Coordination of Voltage Survey

The Auburndale Trouble & Power Quality department or Operations Centers shall be responsible for conducting and coordinating the voltage survey.

a. For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall be responsible for conducting and coordinating the voltage survey.
b. For Kentucky Utilities, each Operations Center shall responsible for conducting and coordinating the voltage survey for its service territory.

6.3 Remedial Measures

6.3.1 Results of the voltage survey shall be forwarded to the appropriate operations or support personnel; e.g., Asset Management’s System Analysis and Planning section.

6.3.2 Remedial action shall be taken to keep voltage levels within standard nominal voltage range(s).

SECTION 7 - SAFETY

7.1 All applicable provisions of the LG&E Safety & Health manual shall be observed.

SECTION 8 – ENVIRONMENTAL

8.1 Not applicable to this procedure.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 Employee Qualifications

Employees performing voltage surveys must be qualified by training and/or experience.

SECTION 10 – EQUIPMENT

10.1 Calibration

10.1.1 Graphic recording voltmeters that are rotated shall be checked with a working standard indicating voltmeter when it is placed in operation or when it is removed.

10.1.2 Indicating voltmeters shall be calibrated twice a year.

10.1.3 A calibration record shall be maintained for each voltmeter showing all pertinent data and the name of person that performed the tests.

SECTION 11 – RECORD KEEPING

11.1 Original records for voltage survey at substations and line regulators shall be kept as follows:

11.1.1 For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall keep the records.
11.1.2 For Kentucky Utilities, the Substation Construction and Maintenance department shall keep the records.
11.2 Original records for voltage survey at “representative points” shall be kept as follows:

11.2.1 For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall keep the records.

11.2.2 For Kentucky Utilities, each operations center shall keep the records for its service territory.

11.3 Original records shall be kept for a minimum of three years and be available for inspection by LG&E Energy Corp.’s customers and KYPSC.

11.4 If charts are used, the following information shall be recorded on each chart:

- Beginning time
- Date of registration
- Time the chart was removed
- The point where the voltage was taken
- Results of the check with the indicating voltmeter
2015 - 2019

LG&E AND KU ENERGY

Specifications for Condition Based

Wood Distribution Pole

Inspection and Remedial Retreatment
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Specifications for Condition Based Wood Distribution Pole
Inspection and Remedial Retreatment

1. GENERAL

1.1. Scope

This specification covers the inspection and supplemental treatment of wood poles on the LG&E AND KU ENERGY distribution system. Not all LG&E AND KU ENERGY poles with distribution facilities are to be inspected under this program. Each pole that is to be inspected will be assigned a basic level of inspection with no mandatory supplemental treatment specified. The base inspection requirement will vary by pole and will be based on specific characteristics of the pole, including the pole’s function, age, original treatment, ownership, treatment history, etc. The identification of any damage, defects or decay found during the base Level of Inspection will trigger progressively increasing detailed Levels Of Inspection and, where necessary, pole treatment. The requirements for the basic inspection levels are detailed in Section 7 – Levels of Inspection. Inspections are to be completed consistent with Section 8 – Inspection Requirements.

The Levels of Inspection are progressive in the detail of inspection and include all of the requirements of all proceeding Levels of Inspection. Levels of Inspection, in progressive order are:

- Asset Data Inspection
- Visual Inspection
- Sound and Bore Inspection
- Full Excavation Inspection

1.2. General Requirements For Inspection

1.2.1. Poles Not Inspected

All Transmission and Foreign owned poles will not receive any level of Inspection unless otherwise specified by the Company. No poles composed of materials other than wood are to be inspected.

1.2.2. Poles 14 Years Old or Less

All Company owned wood Distribution Poles less than 14 years old as well as all poles 15 years or older that have received a supplement treatment within the last 5 years will be Visually Inspected. Visual Inspections include all of the requirements of an Asset Data Inspection where asset data is either verified, if provided, or gathered if not. Each pole shall receive a full Visual Inspection for obvious signs of decay, damage, defects and/or safety hazards. No further work is to be done unless the Visual Inspection provides supportable justification, in the judgment of the Inspector that a more detailed Level of Inspection is warranted. See Section 8.4 – Visual Inspection for the full requirements of this inspection requirement.

1.2.3. Poles 15 Years Old or Greater

Poles 15 years old or greater which have not received a supplemental treatment in the last 5 years are to receive a Full Excavation Inspection. Full Excavation Inspections include all of the requirements of Asset Data, Visual and Sound and Bore Inspections.

Treatment, if any, will be performed only when warranted in the judgment of the Inspector and consistent with this specification and will be based on the actual physical condition of the pole. Treatment requirements are documented in Section 10 – Pole Treatment.
1.3. Key Definitions

1.3.1. General Definitions

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANSI 05.1</td>
<td>American National Standards Institute Standard (ANSI) 05.1: Wood Poles – Specifications and Dimensions, latest revision.</td>
</tr>
<tr>
<td>Company</td>
<td>LG&amp;E AND KU ENERGY owned operating companies including Kentucky Utilities (KU), Louisville Gas and Electric Company (LG&amp;E) and Old Dominion Power (ODP).</td>
</tr>
<tr>
<td>Company Pole</td>
<td>A pole owned by the Company regardless of whether there are any Company owned facilities on the pole.</td>
</tr>
<tr>
<td>Contractor</td>
<td>Firm awarded a formal contract to perform a condition based wood pole inspection and remedial retreatment program on distribution poles on behalf of LG&amp;E AND KU ENERGY Companies as described in this specification.</td>
</tr>
<tr>
<td>Foreign Pole</td>
<td>A pole owned by any other party on which the Company has attached conductors, equipment or facilities.</td>
</tr>
<tr>
<td>Level of Inspection</td>
<td>Baseline inspection requirements for a pole within a given Pole Classification. Work actually completed may be more or less than the baseline requirement depending on the pole’s physical characteristics, its location, condition or past history.</td>
</tr>
<tr>
<td>Pole Classification</td>
<td>Classification of the pole determined by pole ownership and the nature of the conductors, equipment and other facilities placed on the pole. See Section 6.2 – Pole Classifications for specific definitions.</td>
</tr>
</tbody>
</table>

1.3.2. Pole Definitions

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Priority Pole</td>
<td>A pole that in the judgment of the Contractor is in need of immediate replacement. In general includes poles with an average shell of one inch or less OR less than fifty percent (50%) of its original circumference or poles that otherwise present an imminent potential for failure. Priority poles will be reported to the Company’s representative within 24 hours or immediately if extremely hazardous.</td>
</tr>
<tr>
<td>Reject Pole</td>
<td>Any pole designated by the Contractor which, upon inspection, is found deteriorated below a minimum of two-thirds of the ANSI defined strength. Reject Poles will be further classified as a Reject Replacement or as a Restorable Pole based on the actual physical condition of the pole and the actual loading on the pole.</td>
</tr>
<tr>
<td>Reject Replacement</td>
<td>A Reject Pole that has been classified as a Reject that is not suitable for restoration.</td>
</tr>
<tr>
<td>Report Pole</td>
<td>A pole which is determined by Contractor, in Contractor's reasonable opinion, to be inaccessible.</td>
</tr>
</tbody>
</table>
Restoration Pole
A Rejected Pole that, after inspection, meets the criteria for pole restoration. All poles found to be restorable will be externally groundline treated and internally treated if necessary. Fumigant Treatment will not be applied until after the pole has been restored.

RP1 Pole
This category would be your industry standard reject pole, but depending on the circumstance would need to be replaced during a six month period, after the inspection has been documented. This pole would probably be on the low end of remaining strength (closer to 35%) relating to the RP2 definition. This pole could be leaning badly or bowed badly due to hardware (maybe a dead end pole) or terrain. This pole is close to a priority pole, but still falls into the reject category. This pole may have termites that continue to destroy (eat) the wood at a fast pace – even carpenter ants with visual sawdust at the base of the pole. This pole could have lightning damage or a bad split where the top is in jeopardy, insulators hanging off cross arms, animals living in the top (squirrels, etc.), many large woodpecker holes close together, etc.

RP2 Pole
This category would be your industry standard reject pole. This pole probably has remaining strength < 67% and > 35% due to many types of decay or mechanical damage. This pole could be rejected for a split top that runs down through the hardware, where you can see through the split. This type of pole should be replaced during a one year period, after the inspection has been documented. This pole probably does not have any significant (heavy) hardware. This could be a junction pole where the wires help its support.

RP3 Pole
This category would be your industry standard reject that just falls into the reject category. This pole would be on the higher end of remaining strength (closer to 67%). There are no special circumstances with this pole otherwise it would fall into the RP1 or RP2 definitions. This pole would need to be replaced within a two year period, after the inspection has been documented. This pole could very likely have a problem above, otherwise it would fall into the Reinforcable category.

1.3.3. Inspection Definitions (in order of increasing inspection requirements)

Asset Inspection
Poles where the only inspection requirements are to verify and/or gather asset data and perform a casual inspection to identify any obvious damage, defects or safety hazards.

Visual Inspection
Poles that are Asset Inspected and are subjected to a detailed Visual Inspection at and above ground. Includes a visual inspection of equipment, supports, and ancillary equipment such as guys and anchors, push braces, etc. for obvious damage, defects or safety issues.

Sound And Bore Inspection
Poles that are Asset and Visually inspected that are sounded with a hammer from groundline to highest reach and bored with one or more inspection holes to facilitate the detection and extent of internal decay.

Full Excavation Inspection
Poles that are fully inspected including an Asset, Visual and Sound and Bored inspections where the pole is completely excavated to a minimum of 18" below groundline to facilitate a complete assessment of below ground decay and remaining strength. Includes cleaning and
chipping decay and gathering physically information on the extent of decay and the poles physical condition. All Full Excavation poles will be externally treated unless the pole is to be a Reject Replacement or Priority Pole.

1.3.4. Treatment Definitions

External Treatment  
A Company approved, Contractor provided EPA registered below ground preservative treatment and wrap applied to the pole’s exterior at and below grade when designated by the Company or when groundline decay is detected during inspection. All Full Excavation poles will be Externally Treated as part of the Full Excavation Inspection.

Fumigant Treatment  
Application of a Company approved, Contractor provided EPA registered non-liquid fumigant placed internally in a pole where internal decay is detected during inspection or as otherwise directed by the Company or this specification.

Internal Treatment  
Application of Company approved, Contractor provided EPA registered insecticide and preservative solution applied internally to a pole under pressure to any chambers and internal decay voids that constitute a size of 1/2” or larger detected during inspection.

1.3.5. Pole Strength Definitions

ANSI Strength  
Baseline strength of a pole by pole type, height and class as determined from ANSI C05.1 dimensions.

Effective Circumference  
Calculated usable circumference based on actual pole circumference as reduced for damage, defects and decay.

Load Calculations  
Strength calculations used to determine either the Remaining Strength of a pole based on a pole’s actual conditions or to determine Required Strength based on actual pole loading under appropriate NESC criteria.

Remaining Strength  
Percentage of pole strength remaining as a function of the Effective Circumference. Expressed as a percentage of the ANSI C05.1 minimum strength for a given pole type, height and class.

Required Strength  
Pole strength required for the actual loads impressed on a pole under the required NESC Loading District and Grade of Construction.

2. CONTRACTOR REQUIREMENTS

2.1. General Requirements

The Contractor shall furnish all supervision, labor, tools, equipment, PPE, report forms, transportation and material necessary for the inspection and treatment of poles identified by LG&E AND KU ENERGY, hereafter referred to as the Company. Company will furnish copies of this specification and physical or electronic maps showing locations of poles which are the subjects for inspection and/or treatment under this specification.

2.2. Contractor Documentation
The Contractor is required to demonstrate a minimum acceptable level of experience, as determined by the Company, in the inspection, remedial retreatment and reporting requirements consistent with this specification. Years of service in utility field service work other than pole inspection and/or treatment will not count toward this requirement. The Contractor must have documented policies conforming to EPA, OSHA, DOT along with all Federal and Kentucky State Pesticide & Contract regulations. These policies must include, at a minimum:

- Safety Manual
- Hazard Mitigation Plan
- Pesticide Training Manual and test
- Standards for safe storage of preservatives on vehicles
- Operating policies for Contractor's personnel to handle preservatives and procedures for spill containment and disposing of empty containers used for pole treatment
- OSHA regulations involving personal protective equipment
- MSDS Sheets for all chemicals and preservatives utilized

2.3. Contractor Safety & Ethics

2.3.1. Safety

Safe Work Practices are an absolute condition of this contract and contractors are expected to meet or exceed all Company safety guidelines and requirements. Without limiting the foregoing, Contractor agrees to strictly abide by and observe all standards of the Occupational Safety & Health Administration (OSHA) which are applicable to the work being performed. Any unsafe conditions or work practices found by the Contractor during the performance of this Contract will be reported to the Company.

Contractor shall hold Job Briefings daily or when work area changes.

Some areas may require contractor to call BUD (Before You Dig) for location of underground utilities. Contractor will be responsible for call and any expense as of result of underground locating.

Contractor shall be provided with Company’s Contractor Safety Policy and Health and Safety Manual (electronically) and all other Company approved policies and rules applicable to the scope of work, and shall meet the requirements therein as a minimum standard.

*Prior to any work starting a Hazard Analysis and Hazard Mitigation plan must be submitted and approved by the Company.

Contractor is required to have or develop a written safety program and work rules that equal or exceed the requirements of Company’s program and are compliant with applicable laws and regulations. The program plan will include training necessary to prepare or certify Contractor employees coming to work at Company. Additionally, the plan will contain provisions to maintain documentation of training, certifications, etc. required by Contractor employees to perform the work described. This documentation shall be available to Company upon request.

The plan shall include procedures to follow in the event of an injury, incident, or close call involving one of its employees working on Company facilities. Incidents shall be reported immediately to the Company. Incidents and hours of work shall be submitted in the Contractor Data Base monthly. The plan shall be submitted to Company prior to the start of this agreement. Contractor will be expected to participate in Company’s Safety Meetings when requested and to share pertinent information when requested.
No employee of the Contractor will be allowed to perform work on behalf of the Company until the employee has been certified in general safety awareness (Passport) program for contractors. All training shall be entered into the Contractor Data Base and employees provided with a "Passport" card by the contractor prior to beginning work. "Passport" is an instructional general safety training session designed to orient new contractors to the Company’s safety environment, rules, and culture. Contractor will have someone certified at an available "Train the trainer" session to provide their employees "Passport" training annually or use an approved 3rd party trainer at their expense.

Contractor shall furnish Personal Protective Equipment including but not limited to high voltage rubber gloves and sleeves and Flame Retardant clothing for anyone repairing a pole ground wire.

Contractor’s employees will be subject to random safety audits and passport verification.

2.3.2. Ethics

Contractor will be provided with Company’s Contractor Code of Conduct and shall meet the requirements therein as a minimum standard. Contractor shall at all times be solely responsible for complying with all applicable laws and regulations governing the work to be performed or any other rules and regulations that may be issued by the Company during the term of this Contract. Contractor shall abide by all federal, state, and local labor laws.

2.4. Insurance

The Contractor shall maintain throughout the term of this Agreement, in full force and effect, in amounts reasonably satisfactory to Company and otherwise in compliance with applicable law, the following insurance coverages:

- Workers’ compensation
- Commercial general liability (including public liability, personal injury, property damage and contractual liability)
- Automobile liability, naming Owner as an additional insured.

Prior to the commencement of the Work, Contractor shall furnish Company with the necessary documentation evidencing said coverages. Notwithstanding any language to the contrary, any insurance coverage provided by Contractor shall not cover the Company for any negligent acts or omissions of the Company, its employees or agents.

3. CONTRACTOR QUALIFICATIONS

3.1. General Qualifications

All pole inspection and treatment must be performed by professional in-service groundline pole inspection and treatment specialists. Foreman and/or other lead people must demonstrate they have received formal training in inspecting and treatment of in-service wood poles and demonstrate they have a minimum of 3 years’ experience as a pole inspector. The acceptability of experience and training will be determined by the Company.

The Company reserves the right to ask for evidence of previous experience and training in the form of training material, letters of reference and test results. Foreman or other lead people must also possess a Kentucky and Virginia State Pesticide License. All personnel are subject to approval by the Company before awarding the contract or at any time thereafter.

Failure to maintain adequately trained inspectors will result in payment being withheld by the Company in the area being inspected. Company will require that at least one employee be on a job site at all times.
who is able to speak English clearly wherever contact with customers or the public is possible. Direct
contact with Contractor's field Foremen or other lead people by cell phone must be available during
normal business hours.

3.2. Vehicles and Personal Attire

All vehicles must have a professional appearance and be clearly marked with the Contractor's
identification. Vehicles will also be marked to indicate that crews are Contractors of LG&E AND KU
ENERGY companies (LG&E, KU and ODP). Clothing will identify everyone on the work site as
employees of the Contractor. Care will be taken to ensure everyone on a job site maintains a suitable
appearance during the performance of work.

3.3. Supervision

Supervision of pole inspection and treating shall be performed using full-time supervisors located within
the area with at least five (5) years of field experience in in-service pole inspection and treatment.
Supervision must be present in the field every other week for a minimum of one half day for each crew
working for the Company. Supervisors will be required to possess a valid Kentucky State Pesticide
License and hold the position of Supervisor in the State of Kentucky and/or a Virginia State Pesticide
License for work in Virginia.

Personnel not specifically qualified to inspect and treat in-service poles as outlined above shall not be
transferred to work as pole inspectors from other contractual work.

4. WORKMANSHIP AND QUALITY CONTROL

4.1. Workmanship

All work shall be performed in a workmanlike manner and shall be in accordance with this specification
and all applicable Federal and State regulations. The Contractor shall at all times exercise care to
prevent injury to any persons and to prevent damage to Company facilities or to property during
performance of the work.

The Company considers work not in accordance with this specification or work not in accordance with
State or Federal regulations, or unskilled or careless work to be sufficient reason to order the Contractor
to stop work. Work will not be allowed to resume until deficiencies are corrected to the satisfaction of the
Company. Further, the Company reserves the right to require the Contractor to replace any worker
before work is allowed to continue. If not satisfied, the Company will consider this to be just cause for
termination of the Contract.

4.2. Damages

Any damages, real or personal, off the right of way arising directly from the performance of the work
specified herein, or any damages on the right of way as a result of negligent operations, shall be settled
promptly by the Contractor.

4.3. Quality Inspections

A quality control inspection shall be performed for each time period of not less than one week's work but
not to exceed two weeks' previous work. The quality control will be conducted with the Contractor's
Supervisor and Company's representative when available. The quality control inspection shall consist of
the complete re-inspection of those poles selected by the Company's representative to compare the
pole's condition and results shown on the pole report with those existing in the field. The re-inspection
shall include, but shall not be limited to, the re-excavation and retreatment and re-wrapping of those poles that were inspected below groundline.

Contractor's cost of said re-treatments shall be borne by the Contractor. At least 3 poles will be selected for each quality control audit. Poles will be selected at random by the Company's representative. Company shall be issued a copy of the quality control field report.

4.4. Discrepancies and Corrective Action

Any serious errors will be brought to the attention of the Company. Corrective action, satisfactory to the Owner, must be taken by the Contractor to remedy the situation before the next quality control check. The corrective action may include, but not be limited to reworking each pole back to the previous quality control check point at no cost to the Company.

5. REQUIREMENTS FOR PRESERVATIVE APPLICATIONS

5.1. General Restrictions and Requirements

All preservatives and insecticides must be approved for use by the Company prior to any work being performed. Only preservatives registered by the Environmental Protection Agency (EPA) and the appropriate State Department of Agriculture for the intended use will be considered for approval by the Company.

MSDS sheets for all chemicals, preservatives and insecticides will be provided to the Company before use.

All preservatives shall be handled and applied in a manner that will prevent damage to vegetation and property. No preservatives shall be applied by the Contractor where a pole is readily identifiable as:

- Located on any school, preschool, day care or other child care facility
- Located in a vegetable garden
- Within ten (10) feet of a stream or standing water body
- Within (50) fifty feet of a private well.
- Located within active livestock or animal pastures or containment area unless additional precautions are taken to prevent access.

Any container in which a preservative is stored shall be securely locked or bolted to vehicles on the right of way and kept locked when left unattended. Empty preservative containers shall be removed from the right of way and kept in a locked compartment until disposal. Disposal of preservatives and their containers shall be in accordance with the rules and regulations of all appropriate Federal and State agencies.

5.2. Pesticide Licensing and Reporting Requirements

The Contractor shall be a certified commercial pesticide business for the preservative application set forth under this Contract, and shall have each crew supervised by a full time Supervisor who is licensed and certified by the State where the work is performed. The Contractor shall be responsible for the accurate recording and submitting of all pesticide usage forms required by the various pesticide regulatory agencies and for meeting all applicable Federal and State rules and regulations.

The Contractor is required to have in his possession copies of the preservative labels and MSDS sheets for all the preservatives being used. The labels shall list the preservative composition, description, directions for use, precautionary statements, warnings, environmental hazards, practical treatments, storage and disposal instructions and any other relevant information about the preservatives used.
Upon request, the MSDS and labels will be shown to anyone desiring this information. Properly completed shipping papers will also be carried on each vehicle which is transporting pesticides.

5.3. Spill Prevention

Incidental releases of preservative shall be immediately cleaned up in a manner consistent with label requirements, Federal and State regulations, and relevant environmental procedures.

The Contractor shall provide each crew with a spill kit containing sufficient materials for cleaning up and neutralizing potential spills of liquid preservatives. The spill kit shall consist of, but shall not be limited to the following materials:

- Absorption material (such as sawdust or oil dry)
- Baking soda or laundry detergent
- Ammonia (undiluted)
- Trash bags for disposal of waste
- Any other item deemed necessary by the Contractor

5.4. Proper Equipment

The Contractor shall provide each crew with the following EPA required equipment:

- Goggles
- Sleeves
- Non permeable gloves and aprons
- Hard hats
- Change of clothing

The Contractor shall provide a truck that has covers and locks adequate to satisfy federal and state DOT regulations in which to store and transport the preservatives. No chemicals or preservatives will be left unattended at any time unless securely locked in a manner to prevent unauthorized access.

5.5. Pesticide Training

Each pole inspector or foreman shall be required to pass a pesticide training program which addresses biology of wood destroying insects and fungi, the proper and safe handling, storage, disposal and transport of pesticides, product labels and material safety data sheets, emergency procedures for pesticide spills, etc. The Contractor’s Pesticide Training Program is to be in addition to state requirements for applicator licensing.

5.6. Hazard Communication and Safety Program

The Contractor shall provide to its employees a hazard communication program which addresses the purpose of using pesticides, material safety data sheets and product labels, protective safety equipment and clothing and product information. A safety manual and program is to be provided and utilized by the Contractor and its employees.

6. CLASSIFICATION OF POLES

6.1. General

The base level of inspection specified for wood distribution poles will be dependent on Pole’s Classification as modified by factors including pole ownership, age, location, original treatment, previous remedial treatment, etc. Wood poles will be first classified in an order dependent on ownership and the
type of facilities supported on or attached to the pole. Standard Classifications are defined below in Section 6.2.

All LG&E AND KU ENERGY poles that meet more than one classification will be classified by the higher classification (top to bottom). For example, a pole that supports both transmission and distribution conductors will be classified as a transmission pole unless it is not a Company owned pole (Foreign Pole). A Company owned Service Pole that has a street light will be classified as a Service Pole.

Foreign poles will only be classified as a Foreign Pole and all Foreign Poles will be treated the same unless otherwise directed by the Company. The Contractor is responsible for becoming familiar with common LG&E AND KU ENERGY transmission and distribution standards and ownership standards in order to differentiate the various Company Pole Classifications as defined below.

6.2. Pole Classifications

6.2.1. Non-LG&E AND KU ENERGY Pole Classifications

Foreign Pole A pole used for conductor support, guying, secondary or service drops owned by any party other than the Company.

6.2.2. LG&E AND KU ENERGY Pole Classifications

Transmission Pole A Company owned pole supporting any circuit conductors of 69kV nominal phase to phase or above as determined by common construction standards.

Distribution Pole A Company owned pole supporting any distribution primary conductors defined as greater than 480V and less than or equal to 34.5kV nominal phase to phase as determined by common construction standards.

Guy Pole (Transmission Or Distribution) A Company owned pole utilized in whole or in part for guying a Transmission or Distribution Pole.

Secondary Pole A Company owned pole utilized to support secondary conductors defined as 480V nominal phase to phase or less not classified as a Service Pole or Street Light Pole as determined by common construction standards.

Service Pole A Company owned pole used exclusively for the purpose of supporting service drops of 480V nominal phase to phase or less.

Light Pole A Company owned pole used exclusively for the purpose of supporting overhead street lighting, including the attachment of secondary conductors used exclusive for providing service for overhead lighting.

7. LEVELS OF INSPECTION

Only Company owned wood poles are covered under the requirements of this specification. Non-wood distribution structures, transmission poles and transmission guy poles are not covered under this inspection requirement. No Foreign poles are to be inspected. The desired Level of Inspection specified for each pole will be determined by the Pole’s Classification as defined in Section 6.

The Inspection Level is the desired level of inspection to be performed. The pole’s location, the ability to access, physical impediments around the pole (poles in concrete, etc.), the pole’s current condition or past
history of decay may result in a higher or lower level of Inspection than directed in the table below.

Table 7-1 Wood Pole Inspection Criteria

<table>
<thead>
<tr>
<th>Pole Classification</th>
<th>Pole Category</th>
<th>Inspection Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Foreign Poles</td>
<td>All</td>
<td>None</td>
</tr>
<tr>
<td>Transmission Poles</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission Guy Poles</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Distribution Poles</td>
<td>14 years old or less</td>
<td>Visual Inspection</td>
</tr>
<tr>
<td>Distribution Guy Poles</td>
<td>15 years and older that have been retreated within the last 5 years</td>
<td></td>
</tr>
<tr>
<td>Secondary Pole</td>
<td>15 years and older that have not been retreated within the last 5 years</td>
<td>Full Excavation Inspection</td>
</tr>
<tr>
<td>Service Pole</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Street Light Pole</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

8. INSPECTION REQUIREMENTS

8.1. General

The requirements of this specification were developed to provide for a “condition based” inspection program. The basic target Inspection level for any pole is based on the Pole’s Classification as defined in Section 7. Based on the results of the initial inspection, the Contractor can, for just cause proceed with progressively higher levels of inspection and potentially Treatment when justified.

8.2. Preparation For All Inspection and Treatment Options

Before any work is started, all precautions shall be taken to insure that the work can be completed safely and no pole failure will occur during the work.

When work is to be done in close proximity to a home or in an enclosed area in the rear of a home, the property owner should be notified that the pole is to be inspected. Brush will be removed from around the pole to the extent necessary to allow for proper inspection and/or excavation. If the property owner denies access for any reason, the denial will be indicated in the inspection data the pole will be considered a “Report Pole”.

Contractor will not inspect or perform work on poles inaccessible by acts of God or by any causes beyond the control of the Contractor. Any pole that cannot be inspected safely will not be inspected. Reason for the lack of inspection indicated in the inspection data. There will be no charge associated with inaccessible poles.

8.3. Asset Inspection

Every pole designated for inspection shall receive at a minimum, an Asset Inspection before any other work is done. An Asset Inspection includes recording (if missing) or verifying (if provided) pole asset information including (at a minimum):
• Pole ownership
• Pole identification number (if provided or tagged)
• GPS coordinate and/or location
• Pole height and class
• Manufacturer
• Manufacture date
• Pole species
• Original pole treatment
• Date of last remedial treatment (if applicable)

Other data collection or work may be incorporated into Asset Inspections when directed or approved by the Company. Inaccessible poles will be noted as such and will not be visually inspected. Reason for the lack of inspection will be noted in the remarks column of the pole report. There will be no charge associated with inaccessible poles.

When decay or insect damage is suspected or detected or for other reasons within the Contractor’s discretion, Company owned poles designated for only an Asset Inspection will proceed to a full Visual Inspection where warranted.

8.4. Visual Inspection

Visual Inspections include all of the requirements of an Asset Inspection.

A Visual Inspection is made from groundline to the top of the pole and includes a visual inspection of all equipment and supports including ancillary equipment such as guys and anchors, push braces, etc. The inspector shall document the condition of the pole and shall record any of the following:

• Structural defects due to top rot, woodpeckers, lightning, compression wood, mechanical damage, excessive checking, bowing or leaning, etc.
• Obvious groundline decay and/or insect damage.
• Broken or damaged equipment
• Obvious clearance violations on the pole such as clearances to communications conductors, etc.
• Obvious clearance violations in any span adjacent to the inspected pole to ground, swimming pools, other structures, trees, buildings, etc.
• Unapproved non-utility attachments (basketball goals, private lighting, etc.).

Note: Communications attachments, street and traffic signs and controls and banners from public or quasi-public agencies are considered approved attachments for the purpose of this item.

Prods, bars or picks shall not be used to determine the extent of external decay. Sounding may be used to further assess the condition of the pole.

If the inspector can determine without further inspection that the pole is not suitable to remain in service it shall be visually rejected and the Contractor shall bill the Company for a “Visual Inspection”. Imminent hazards shall be reported to the Company immediately.

When decay or insect damage is suspected or detected or for other reasons within the Contractor’s discretion, Company owned poles designated for only a Visual Inspection will proceed to a Sound and Bore Inspection or Full Excavation Inspection and where appropriate, Treatment.

8.5. Sound and Bore

Sound and Bore Inspections include all of the requirements of an Asset and Visual Inspection.

Poles shall be sounded with a hammer from the lowest accessible point to as high as an inspector can reach in order to locate exterior decay or interior pockets of decay. Hammer marks should be visible to
indicate that the area was sounded.

Inspector shall bore the pole at least once to detect interior pockets or decay using a 3/8" bit. Bore holes should be made in the line of lead unless the inspector determines boring at other locations may provide better identification of decay. Bore hole shall be located near the groundline and should be drilled at a 45 degree downward angle to a depth of the center line of the pole in the line of the pole. Only sharp bits are to be used for boring and special attention shall be paid to the nature and characteristics of the shavings. A shell thickness indicator shall be used to detect the extent of any interior decay. If decay is present, the pole shall be bored a sufficient number of times to determine location and extent of decay. Detail on the type, size and location of pockets and decay will be noted on the report.

If heart rot or enclosed decay pockets are evident in a pole, a minimum of five (5) borings will be taken to determine the size and extent of decay.

Bored holes shall be plugged with tight-fitting 7/16” diameter treated wood dowels.

If the inspector can determine without further inspection that the pole is not suitable to remain in service it shall be rejected and the Contractor shall bill the Company for a "Sound and Bore Inspection". Imminent hazards shall be reported to the Company immediately.

When groundline decay, insect damage, internal decay pockets or internal decay is suspected or detected or for other reasons within the Contractor’s discretion, Company owned poles designated for only a Sound and Bore Inspection will proceed to a Full Excavation Inspection and where appropriate, Treatment.

8.6. Partial Excavation

Occasionally, Partial Excavation may be necessary for the following but not limited to reasons:

- In pavement or concrete
- With underground power risers (unless approved by the Company)

Partial Excavation inspections include all of the requirements of an Asset, Visual and a Sound and Bore Inspection.

Where excavation is not possible the reason will be noted in the report and the Contractor will bill the pole as a “Sound and Bore” Inspection.

If no surface decay is suspected and the borings indicate no internal decay or pockets, no further action is required. The partial excavation will be back-filled and the soil reasonably compacted.

If the inspector can determine without further inspection that the pole is not suitable to remain in service it shall be rejected and the Contractor shall bill the Company for a "Partial Excavation" inspection. Imminent hazards shall be reported to the Company immediately.

8.7. Full Excavation

Full Excavation inspections include all of the requirements of an Asset, Visual Inspection and a Sound and Bore Inspection. All Full Excavation Poles with be externally groundline treated.

8.7.1. Excavation

All poles that have not been rejected on the basis of the above ground Visual and Sound and Bore Inspection shall be excavated to a depth of 18” below groundline. Exceptions include poles:

- In pavement or concrete
• In vegetable gardens
• With underground power risers (unless approved by the Company)

Where excavation is not possible the reason will be noted in the report and the Contractor will bill the pole as a "Sound and Bore" Inspection.

The excavation will be approximately 10" from the pole at ground level and taper to 4" from the pole at the 18" depth. For excavation in lawns, sod grass areas or gardens, care will be taken to keep surrounding area as clean as possible. The sod around pole shall be carefully cut and neatly stacked. Poles installed on slopes shall be excavated to a minimum depth of 18" on the down slope side and 18" on the high side. Tarpaulins or ground cloths shall be used whenever possible to minimize the possibility of any property damage and to aide in the tracking of excavated holes. (Exceptions should be rare, and would include situations where the slope is too steep or the ground surface to uneven to allow for effective use).

8.7.2. Chipping

Significant loose and decayed wood is to be removed from 18" below groundline to 6" above groundline. A quality chipping tool will be used for this procedure to obtain a smooth, clean removal of wood. External decay pockets will be shaved or chipped to remove decay from pole. It is essential that exterior decay be removed from the hole and surrounding ground and disposed of properly. Care should be taken not to remove good wood as this will increase the potential for decay and will reduce the strength of the pole. The pole will be scraped using a check scraper to remove dirt from the treatment zone.

8.7.3. Damaged Ground Wires

Contractor shall use extra care to avoid damaging or cutting pole grounds. Ground wires broken by the Contractor shall be repaired by the Contractor at no charge to the Company. The Contractor shall repair broken ground wires using proper PPE and workers qualified to safely reconnect the ground in a method acceptable to the Company.

8.8. Digital Collection for Rejected Poles

All rejected poles shall have two photos. The unit shall consist of two digital images of each reject pole. One image of the pole number and one image of the top of the pole where all material/equipment would be captured in the image.

8.9. Pole Identification Number

If an inspected pole does not have an identification number, contractor shall attach pole number.

9. EVALUATION

9.1. Obvious Rejects

Poles obviously unsuitable to remain in service will be classified as a Reject Replacement Pole or a Priority Pole. If excavation was performed, soil will be carefully returned to the hole and lightly tamped. No further work will be done. The pole will be properly tagged as a Reject Replacement Pole or a Priority Pole in accordance with Section 12 – Pole Marking. Priority Poles will be reported to the Company’s designated utility contact within 24 hours and details on the pole’s condition and reasons for classifying the pole as a Priority Pole will be provided at that time.

9.2. Effective Circumference

A qualified Inspector will measure the actual minimum circumference at or below groundline wherever the
least sound wood is present. An Effective Circumference will be determined in the field by adjusting the actual circumference to account for external decay pockets and internal decay by the use of Company approved tables, calculators or handheld software.

9.3. Remaining Strength

The Effective Circumference in conjunction with Company approved tables, calculators or handheld software will be used to determine the effective Remaining Strength as a percentage of specified ANSI Strength (ANSI 05.1, current revision) for the pole type, height and class. Remaining Strength will be calculated as a percentage of ANSI 05.1 strength and the percentage recorded.

Poles with Remaining Strength greater than or equal to 67% will be treated in accordance with Section 10 - Pole Treatment.

Poles with Remaining Strength of more than 35% but less than 67% will be subjected to a Load Calculation to determine if the Remaining Strength is adequate for the actual loads impressed on the pole under NESC loading requirements.

9.4. Load Calculation

A Load Calculation will be performed on any poles with Remaining Strength greater 35% but less than 67% (2/3) of the ANSI Strength that is in otherwise suitable condition to remain in service. The Load Calculation will be used to determine if the pole’s Remaining Strength meets or exceeds the Required Strength as determined by the appropriate NESC loading requirements. Required Strength will be determined based on the following requirements:

9.4.1. Loading District

Unless otherwise directed by the Company, the following NESC loading criteria will be used to determine Required Strength.

- Kentucky: NESC Medium Loading
- Virginia: NESC Heavy Loading

Where any portion of the structure or facilities supported by the structure exceeds sixty feet (60’) above ground NESC High Wind and Heavy Ice criteria will also be considered.

9.4.2. Grade of Construction

<table>
<thead>
<tr>
<th>NESC Loading Criteria</th>
<th>Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grade B</td>
<td>Crossings of Limited Access highways, railroad tracks, navigable waterways requiring waterway crossing permits</td>
</tr>
<tr>
<td></td>
<td>Lower voltage circuits placed above or crossing circuits of 8.7kV phase to ground or higher</td>
</tr>
<tr>
<td></td>
<td>Crossings of any lines where the crossed line must meet Grade B criteria whether crossed on a common structure or not.</td>
</tr>
<tr>
<td>Grade C at Crossings</td>
<td>Any other poles not required to meet Grade B construction</td>
</tr>
</tbody>
</table>
Poles where the Remaining Strength exceeds the Required Strength which are otherwise in acceptable condition to remain in service will be treated in accordance with the requirements in Section 10 - Pole Treatment.

9.5. Reject Poles

Poles below minimum Required Strength and poles unsuitable to remain in service in their present condition shall be classified as a Reject Pole, and so marked in the field and reported. Poles classified as a Reject Pole will be further classified as either a Reject Replacement or as a Reinforcable Pole based on the criteria below. The pole will be tagged with the appropriate tag in accordance with Section 12 – Pole Marking.

9.5.1. Reinforcement Candidates

Poles with a minimum shell equal to or greater than 2 inches will be considered a Candidate for Reinforcement and evaluated under Section 9.6.

9.5.2. Reject Replacement

The following poles will be classified as Reject Replacements. No treatment will be applied and any excavation will be carefully filled and lightly tamped back in place. Pole will be recorded as a Reject Replacement or Priority Pole.

- Poles with a shell thickness less than 2” will be rejected.
- Poles with a minimum shell of 1 inch or 50% of original circumference or less will be designated a "Priority Pole". Priority Poles will be reported to the Company's designated utility contact within 24 hours and details on the pole's condition and reasons for classifying the pole as a Priority Pole provided at that time.

9.6. Reinforcable Candidates

When the initial inspection or loading analysis results in the rejection of a pole, and the pole is otherwise serviceable the pole shall be marked for replacement or reinforcement. The following inspections shall be performed to determine if the pole is a viable candidate for reinforcement.

The pole shall be sounded thoroughly concentrating on the zone fifteen inches (15”) to 5 feet above groundline.

To be considered a Candidate for Reinforcement, the pole must meet both of the following requirements.

1. A minimum of two 3/8-inch diameter borings shall be made at 5 feet above groundline, to determine the average shell thickness at this level. The first boring shall be made perpendicular to the line of lead. A second boring shall be made opposite (180 degrees) the first boring, whenever possible. Additional borings should be made, as necessary, to determine the average shell thickness. If the average is less than the required four inches, the pole should be checked at 6 feet to determine if the required shell thickness exists at 6 feet. If the average shell thickness at either 5 feet or 6 feet above the groundline is four inches the pole is a candidate for reinforcement provided all other requirements are met.

2. A minimum of two 3/8-inch diameter borings shall be made at 15 inches above groundline, to determine the average shell thickness at this level. The first boring shall be made perpendicular to the line of lead. A second boring shall be made opposite (180 degrees) the first boring, whenever possible. Additional borings shall be made, as necessary. If the average shell
thickness, at 15 inches, is two inches or greater, the pole is a candidate for reinforcement. Poles with less than two inches of average shell, at 15 inches above groundline, can be reinforced if they have an average shell thickness of two inches or greater at 26 inches and the requirements and all other requirements are met.

If the pole fails to meet either of these requirements, the pole will be classified as a Reject Replacement. The pole will be marked with a reject tag and any excavation will be carefully filled in.

If the pole meets both of the minimum shell thickness requirements, the pole will be treated under the requirements of Section 10 - Pole Treatment except no fumigant will be applied. If it was necessary to go to 26 inches or 6 feet to obtain the required shell thickness, a notation will be made in the pole record.

All inspection holes shall be plugged with 7/16” diameter treated wood dowels.

10. POLE TREATMENT

10.1. Treatment Schedule

Poles will be treated according to the following schedule.

10.1.1. Poles With Internal Decay Pockets of 1/2” Or Greater

The following poles will be Internally Treated:

- All poles with internal decay pockets will be treated with an Internal Treatment, a Fumigant Treatment and an External Treatment where possible unless the pole is to be a Reject Replacement. This includes all poles classified as Reinforcement Candidates.

10.1.2. Poles With Internal Decay

The following poles with be Fumigated:

- All poles with internal decay but no decay pockets will be Fumigated and Externally Treated where possible unless the pole is to be a Reject Replacement. Note: Poles which are to be classified as Reinforcement Candidates will not be fumigated until after the pole is reinforced.

- All poles which are designated or progress to the Full Excavation requirements but can’t be fully excavated due to risers or obstructions (such as poles in concrete) will be treated with a Fumigant Treatment even when no internal decay is detected.

- All poles which are designated or progress to the Full Excavation requirements that cannot be excavated (Except Section 5.1, in concrete, etc.)

10.1.3. Groundline Decay

The following poles will be Externally Treated:

- All fully excavated poles shall be treated in accordance with External Treatment regardless of the presence of decay unless the pole is to be a Reject Replacement.

10.1.4. Previously Treated Poles
Poles designated for any level of inspection that have been inspected and treated within the last 5 years will receive only a visual inspection.

All other poles that have been previously treated will receive a full excavate and treat inspection consistent with the requirements of Section 8 – Inspection Requirements. If Kraft paper is removed to facilitate inspection, then it should be reapplied when the inspection is complete. Where external or internal decay is detected or has been reestablished, treatment will be performed consistent with the requirements of Section 10 - Pole Treatment with the following exception:

Any pole previously treated with Internal or Fumigant treatment will be retreated in the same manner as the previous treatment cycle regardless of whether internal decay has been reestablished. Groundline treatment will be reapplied only if groundline decay is detected and/or has been reestablished.

10.2. Application of External Groundline Treatment

All poles which are excavated and serviceable or Reinforcable are to be groundline treated. Only a Company approved, EPA registered External Treatment will be used.

10.2.1. Application

Preservative paste shall be applied to the pole a minimum of 1/16" thick or to the minimum requirements specified by the manufacturer. Treatment will extend from 18" below groundline to 2" above groundline unless otherwise directed by the Company. Unapproved materials will not be accepted by Company. All restorable candidates will be externally treated.

All exposed pockets and checks will be liberally treated using a brush or trowel. Where obstructions occur such as fences, curbs, and walls, the preservative shall be applied in excessive amounts next to the obstruction to insure complete coverage.

10.2.2. Wrapping of External Treatment

A poly backed Kraft paper is to be applied over the wood preservative. The moisture barrier shall cover the preservative at 18" depth and extend 2" above the top of the treatment zone, for a total of 22" wide. It shall be of sufficient length to go around the pole with a minimum overlap of approximately 4" and shall be stapled to the pole at the top and side seams of the barrier. The mil thickness of the moisture barrier shall not be less than 4 mils thick.

Pasture wrap shall also be used in areas of livestock; it will be stapled to top of the moisture barrier to act as an additional protective barrier.

10.3. Application of Fumigant Treatment

Fumigant shall be applied as specified under Section 10.1. Only a Company approved, non-liquid (vial based or granular) EPA registered Fumigant will be used.

10.3.1. Application

Poles will be bored with 7/8" slanting downward holes to a minimum of 10" depth according to the following schedule. Proper protective equipment will be utilized to apply the fumigant. Following treatment all holes will be plugged using a tight fitting 15/16 x 3" treated wood dowel or composite plastic plug.
John K. Wolfe

Pole Circumference | Number of Holes Drilled
--- | ---
30" to 35" | 3 holes spaced 120 degrees apart and 6" to 8" higher than the previously bored hole.
36" to 49" | 4 holes spaced 90 degrees apart and 6" to 8" higher than the previously bored hole.
50" to 59" | 5 holes spaced 72 degrees apart and 6" to 8" higher than the previously bored hole.
60" & larger | 6 holes spaced 60 degrees apart and 6" to 8" higher than the previously bored hole.

The number of treatment holes will be recorded in the pole record.

10.4. Application of Internal Treatment

Internal Treatment shall be applied as specified under Section 10.1. Only a Company approved, EPA registered Internal Treatment will be used.

10.4.1. Application

Poles containing decay pockets of 1/2" or larger shall be treated by pumping the preservative into the cavity under pressure through a series of 3/8" diameter holes. The solution will be applied at a minimum pressure of 40 psi or per manufacturer's recommendations. Beginning with the lowest hole, pump the preservative into the cavity until the material flows out of the next highest hole. This hole is then plugged and additional preservative is pumped into the cavity until the cavity is filled or a maximum of one gallon is used. Sufficient holes will be bored and preservative used to assure coverage of decayed area. All holes will be plugged with 7/16" treated wood dowels. If wood destroying insects are encountered in the pole, sound the pole to locate top of the insect gallery and drill enough holes to thoroughly treat wood and flood the galleries.

11. SITE RESTORATION

11.1. Damaged Ground Wires

Ground wires and risers will be carefully inspected after work is complete and before backfilling. Ground wires broken by the Contractor shall be repaired by the Contractor at no charge to the Company. The Contractor shall repair broken ground wires using workers qualified to safely reconnect the ground in a method acceptable to the Company.

11.2. Backfilling

After excavation and/or treatment, all poles will be solidly back-filled. The first half of excavation will be back-filled and tamped completely around the pole; the second half back-filled and tamped completely around the pole. The excess earth should be banked up to a maximum of 3" above normal ground level to allow for settlement. In grass areas the sod shall be carefully placed around the pole. Rocks or stones should not be laid against the pole except where they serve to key the pole or where no other fill is available. Extreme care should be taken not to tear the moisture barrier while back-filling.

11.3. Clean-up

No debris, loose dirt, wood shavings, etc., shall be left in the pole area. Private property turf, including
that between curb and sidewalk, bushes, and plants, and shrubbery are to be replaced with care. If any preservative is spilled on the ground, it shall be cleaned up immediately. All containers shall be disposed of according to approved environmental practices.

12. POLE MARKING

12.1. Tagging (See Attachment 1)

All tagging will be approved or specified by the Company before use. All pole tags to be installed at or above 7 feet from the ground line.

All rejected poles are to have one reject tag placed on them at approximately 7 feet from groundline. In addition to the reject tag, red flagging, or spray paint, to be furnished by the Contractor if directed by the Company, will be applied to help in the identification of priority or rejected poles.

Poles rejected but capable of being restored are to be properly marked with an appropriate reject tag.

The Contractor’s inspector will make a notation on the pole inspection and treating report as to whether the pole can or cannot be restored. If the pole has other damage of any kind, it will be noted in the remarks column.

Priority poles are to have two reject tags at approximately 7' from groundline.

13. Data Requirements

Company desires to conduct a comprehensive pole inspection and maintenance program. The data to be collected will include pole attributes, pole condition and treatment and may include additional information if requested or specified by the Company. Data will be submitted electronically in a format suitable for viewing, searching and reporting. On-line or proprietary data formats must be exportable to other formats acceptable to the Company Access, Excel, etc. and suitable to be migrated into other Company asset information systems.

The Contractor will be required to demonstrate a successful history in completing similar inspection and treatment projects in electronic format. The Contractor will include, as part of the prices set forth in the Contract, all required hardware, software, setup services, field services, data processing, project management, data deliverables and customer support necessary to fulfill the outlined project requirements.

The Company will work with the Contractor to provide pole facility data and attributes in a mutually agreeable format to facilitate the completion of the inspection work. The Company will provide, where available geospatial and attribute data prior to beginning inspection work. Omissions and errors in Company provided attribute data will be gathered and/or corrected by the Contractor as part of the inspection work.

13.1. Data Deliverables

Attribute inspection and treatment data, including digital photos of pole rejects, shall be provided to the Company electronically in a timely basis. The data must provide information that can be used to reconcile billings as well as to allow timely decisions on pole repair, replacement or maintenance activities. The method of delivering electronic data (email, CD, online) will be approved by the Company.

13.2. Archiving
Contractor will archive the pole condition and attribute data for 12 months after the year in which the inspection is performed.

14. INVOICING

14.1. Billing

Contractor shall furnish Company with required deliverables in electronic format in no more than two week work increments. Billings will be itemized for all charges and submitted either electronically or through the mail, from pole inspection reports.
Attachment 1- INSPECTION AND TREATMENT TAGS

<table>
<thead>
<tr>
<th>Tag Description</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>INSPECTION AND TREATMENT TAGS</strong></td>
<td></td>
</tr>
<tr>
<td><img src="attachment_image1.png" alt="Oval tag" /></td>
<td>This tag is an example of a contractor’s tag. This oval tag is to be used whenever any inspection involves more than the requirements of an Asset Inspection but less than a Full Excavate (and Treatment) Inspection. This will include “Visual Inspection”, “Sound and Bore” or “Partial Excavate Inspections. The tag should incorporate the contractors name and the year the work is performed.</td>
</tr>
<tr>
<td><img src="attachment_image2.png" alt="Round tag" /></td>
<td>This tag is an example of a contractor’s tag used when a Full Excavate Inspection has been done. This round tag represents an inspection via a full 18” dig and treatment with an approved preservative paste. The tag should incorporate the contractors name and year the work is performed.</td>
</tr>
<tr>
<td><img src="attachment_image3.png" alt="Fumigant tag" /></td>
<td>The fumigant tag is used whenever a fumigant is applied to a pole. This tag will be used in conjunction with one of the above tags depending on the type of inspection performed. The tag will identify the type of fumigant used.</td>
</tr>
<tr>
<td><img src="attachment_image4.png" alt="Internal Treat tag" /></td>
<td>The Internal Treat tag is used whenever Internal Treatment is injected into the pole. This tag will be used in conjunction with one or more of the above tags depending on the type of inspection performed.</td>
</tr>
<tr>
<td><strong>REJECT TAGS</strong></td>
<td></td>
</tr>
<tr>
<td><img src="attachment_image5.png" alt="Yellow reject tag" /></td>
<td>One yellow reject tag is used to denote that the pole is a Reinforcable Reject.</td>
</tr>
</tbody>
</table>
One white (or silver) tag is used to denote a Replacement Pole (non-Reinforcable Reject).

OR

Red With Crossed Out Arrow or Two White Square tags are used to denote a Danger or Priority Pole that is a Priority Replacement Pole (non-Reinforcable). The direction of the arrow is to be aligned to indicate the general location of the major defect.
**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2016-00371**

Response to Attorney General’s Initial Data Requests for Information  
Dated January 11, 2017

**Question No. 401**

Responding Witness: John K. Wolfe

Q-401. Regarding the 2-year distribution capital investment shown in the table on page 46 of the Testimony of Paul W. Thompson, provide the following:

a. For LG&E historic annual investments for each category over the past 5 years (2012-2016).

A-401.

a. Historical results (in Millions):

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
</tr>
</thead>
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<tr>
<td>Distribution Automation</td>
<td>0</td>
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<tr>
<td>Transformer Contingency</td>
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<tr>
<td>New Business</td>
<td>16</td>
<td>20</td>
<td>23</td>
<td>26</td>
<td>27</td>
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<tr>
<td>Repair and Replace</td>
<td>26</td>
<td>31</td>
<td>32</td>
<td>40</td>
<td>41</td>
</tr>
<tr>
<td>All Other</td>
<td>13</td>
<td>14</td>
<td>13</td>
<td>16</td>
<td>12</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>55</strong></td>
<td><strong>65</strong></td>
<td><strong>68</strong></td>
<td><strong>82</strong></td>
<td><strong>80</strong></td>
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</tbody>
</table>
Question No. 402
Responding Witness: Lonnie E. Bellar

Q-402. Regarding section 4.1.2 of Exhibit PWT-2 provide the total work estimate developed by Environmental Consultants, Inc. regarding vegetation management.

A-402. Environmental Consultants, Inc. identified $56.3 million dollars of vegetation work on the LG&E and KU transmission system.
Question No. 403

Responding Witness: Lonnie E. Bellar

Q-403. Regarding section 4.1.3 of Exhibit PWT-2 provide detailed annual information regarding the 5-year line sectionalizing program including line segments identified for improvement and sectionalization solutions and related costs, as well as expected SAIDI improvement related to each installation.

A-403. Based on historical outages, the Company expects a reduction to SAIDI through reduced restoration times in the future, however the Company did not project SAIDI improvement by installation.

See attached.
Project
150846
151744
151811
151816
152123
152134
152135
152136
152138
152139
152140
152142
152143
152144
152146
144364
144632
144634
144636
144637
148370
148371
150845
151745
151746
151814
151815
152108
152109
152118
152119
152120
131374
134200
137739
137740
144061
144062
144975
147480
147481
147482
147486
147487
147488
147489
147490
147491
147492
147493
147494
147495
147496
147497

Bud Description
REL-Madisonville Loop-P&C
REL-Campbellsville 605 Switch
REL-Rockwell Motor-Auto
REL-Paris 819-615 Motor-Auto
REL-Harmony Landing Auto
REL-Radcliff Motor-Auto
REL-GE Lamp 615 Motor-Auto
REL-Esserville Motor-Auto
REL-Irvine Motor-Auto
REL-Hughes Lane 660-615 Auto
REL-Etown 4 811-615 Motor-Auto
REL-Morehead W 406-605 Auto
REL-Corbin 1 844-605 Auto
REL-Lemons Mill Motor-Auto
REL-Mt Sterling 737-615 Auto
REL-Parkers Mill 604 Brkr Adds
REL-Cawood 604 Brkr Addition
REL-FMC 604 Brkr Addition
REL-Stanford 604 Brkr Add
REL-Camargo 604 Brkr Add
REL-Hoover 604 Breaker Add
REL-Earlington 604 Brkr Add
REL-Madisonville Loop-Subs
REL-Warsaw 615 Switch Motor
REL-Hodgenville Switch Motor
REL-Stanford 848-635
REL-Somerset N 92-605 Motor
REL-Centerfield 604 Brkr Add
REL-Smyrna 604 Brkr Add
REL-Shannon Run Brkr Rpl
REL-Lagrange East 604 Brkr Add
REL-Munfordville Brkr Add
REL WEDONIA 138KV SWITCH
REL JFRSNTWN 138 SWTCH
REL ONTON 69KV SWITCH
REL POOLE 69KV SWITCH
REL TUNNELL HILL SWITCH
REL KEOKEE SWITCH
REL CLAYS MILL MOS
REL Esserville Switch
REL Kenton Switch 91-6
REL Campbellsburg Switch
REL Dwina Switch
REL Harlan 557 Tap Switch
REL Osaka East Switch
REL Rogers Gap Switch
REL Airline Road Switch
REL Versailles West Switch
REL Dycusburg Switch
REL Hamblin Tap Switch
REL Paint Lick Switch
REL Belt Line Switch
REL McKee Road Switch
REL Bailey Creek Switch

Code
SWITCH
SWITCH-AUTO
SWITCH-AUTO
SWITCH-AUTO
SWITCH-AUTO
SWITCH-AUTO
SWITCH-AUTO
SWITCH-AUTO
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SWITCH-MOTOR OPERATED
SWITCH-MOTOR OPERATED
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SWITCH-MOTOR OPERATED
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Line Position
Green River to Earlington North 69 kV line
Lebanon to Taylor County 69 kV line
Loudon Avenue to Winchester 69 kV
Millersburg (604) to Paris (634) 69 kV
Harrods Creek to Harmony Landing 69 kV line
Rogersville to Vine Grove 69 kV
American Avenue to Higby Mill to Parkers Mill 69 kV line
Bond to Dorchester 69 kV line
Beattyville to West Irvine 69 kV line
Lexington Plant to Paris 69 kV line
Elizabethtown to Hodgenville EKPC 69 kV interconnection
Rodburn to Farmers 69 kV line
Farley to Sweet Hollow 69 kV line
Adams to Haefling 69 kV line
Spencer Road to Clark County 69 kV line
Lexington Plant to Pisgah 69 kV line
Pocket to Catrons Creek to Rocky Branch 69 kV line
Lansdowne 614 to Loudon Avenue 614 69 kV line
Boyle County to Lancaster 69 kV line
Spencer Road to Clark County 69 kV line
Adams to Haefling 69 kV line
Green River to River Queen to Walker 69 kV line
Green River to Earlington North 69 kV line
Warsaw to Owen County EKPC 69 kV interconnection
Elizabethtown to Hodgenville EKPC 69 kV interconnection
Boyle County to Lancaster 69 kV line
Elihu to Somerset North 69 kV 96-634
Middletown to Trimble County Switching 138 kV line to Centerfield 138/69 kV tran
Fairmount to Mud Lane 69 kV line
Tyrone to Higby Mill 69 kV line
Eminence to Centerfield 69 kV line
Barren County EKPC to Bonnieville EKPC 69 kV line
Rodburn to Kenton 138 kV line
Watterson to Middletown 138 kV line
Corydon to Calhoun 69 kV line
Corydon to Calhoun 69 kV line
Corydon to Calhoun 69 kV line
Pocket to Imboden 69 kV
Higby Mill 724 to Brown North 734 138 kV line
Bond to Dorchester 69 kV line
Kenton to Murphysville EKPC 69 kV interconnection
Carrollton to Eminence 69 kV
Dorchester to St Paul 69 kV line
Harlan Y to Evarts to Pocket 69 kV
Lynch to Imboden 69 kV line
Scott County to Delaplain 69 kV line
Corydon to Green River Steel 69 kV line
East Frankfort to Tyrone 69 kV line
Princeton 3-654 to Crittenden County 189-604 69 kV line
Pocket to Catrons Creek to Rocky Branch 69 kV line
Lake Reba to Okonite 69 kV line
Lexington Plant to Haefling 69 kV line
Elihu to Somerset North 69 kV 96-624
Evarts to Arnold 69 kV

2017
$0
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$200,000
$0
$0
$200,080
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$200,080
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Attachment to Response to AG-1 Question No. 403
Page 1 of 3
Bellar


147498 REL Bardstown Ind Switch SWITCH Bardstown to East Bardstown EKPC 69 kV interconnection $0 $0 $360,857 $0 $0
147499 REL Four Mile Switch SWITCH Pineville 192-624 to Rocky Branch 225-604 69 kV line $0 $0 $495,857 $0 $0
147500 REL Owingsville Switch SWITCH Foreign EKPC Goddard to Hope 69 kV $0 $0 $360,857 $0 $0
147501 REL Echols Switch SWITCH Ohio County to Indian Hill 69 kV $0 $0 $360,857 $0 $0
147502 REL Bens Branch Switch SWITCH Imboden to Dorchester 69 kV line $0 $0 $360,857 $0 $0
147503 REL Nelson Switch SWITCH Green River to Indian Hill 69 kV line $0 $0 $360,857 $0 $0
147504 REL Madisonville North Switch SWITCH Nebo 228-644 to Earlington North 202-614 69 kV line $0 $0 $0 $381,235 $0
147505 REL Kuttawa Switch SWITCH Princeton 3-654 to Crittenden County 189-604 69 kV line $0 $0 $0 $381,516 $0
147506 REL Woodlawn Switch SWITCH Bardstown to Hodgenville EKPC 69 kV interconnection $0 $0 $0 $381,516 $0
147507 REL Vine Grove Switch SWITCH Rogersville to Vine Grove 69 kV $0 $0 $0 $381,516 $0
147508 REL Corbin East Switch SWITCH Farley to Sweet Hollow 69 kV line $0 $0 $0 $381,516 $0
147509 REL Taylorsville Switch SWITCH Finchville to Bardstown 69 kV $0 $0 $0 $381,516 $0
147510 REL Wise Tap Switch SWITCH Bond to Dorchester 69 kV line $0 $0 $0 $381,516 $0
147511 REL Manitou Switch SWITCH Nebo 228-634 to Earlington North 202-604 69 kV line $0 $0 $0 $381,516 $0
147512 REL Nicholasville Switch SWITCH Higgins Mill to Trim Master tap 69 kV line $0 $0 $0 $381,516 $0
147513 REL Camp Breckenridge Switch SWITCH Morganfield to Nebo 69 kV $0 $0 $0 $381,516 $0
147515 REL Lebanon W31 Switch SWITCH Lebanon to Taylor County 69 kV line $0 $0 $0 $0 $420,175
147516 REL Paris City Switch SWITCH-MOTOR OPERATED Millersburg (644) to Paris (624) 69 kV $0 $0 $0 $0 $420,175
147517 REL Benham Switch SWITCH Lynch to Arnold 69 kV line $0 $0 $0 $0 $420,175
147518 REL Somerset South Switch SWITCH Somerset EKPC to Russell County EKPC 69 kV interconnections $0 $0 $0 $0 $420,175
147519 REL Green River W86 Switch SWITCH Taylor County to Green County EKPC 69 kV interconnection $0 $0 $0 $0 $420,175
147520 REL Bear Branch Switch SWITCH Imboden to Dorchester 69 kV line $0 $0 $0 $0 $420,175
147521 REL Spindletop 823 Switch SWITCH Adams to Haefling 69 kV line $0 $0 $0 $0 $538,675
147522 REL Fies City Switch SWITCH Green River to Earlington North 69 kV line $0 $0 $0 $0 $420,175
147523 REL Morehead West Switch SWITCH Rodburn to Farmers 69 kV line $0 $0 $0 $0 $420,175
147534 REL Radcliff Switch SWITCH Rogersville to Vine Grove 69 kV $0 $0 $0 $0 $0
147565 REL Haley MOS SWITCH Laidford Avenue to Winchester 69 kV $450,000 $0 $0 $0 $0
147570 REL Motor Op Switches KU 2019 SWITCH-MOTOR OPERATED Undetermined $0 $1,506,612 $0 $0 $0
147593 REL Motor Op Switches KU 2020 SWITCH-MOTOR OPERATED Undetermined $0 $1,768,425 $0 $0 $0
147594 REL Motor Op Switches KU 2021 SWITCH-MOTOR OPERATED Undetermined $0 $1,796,760 $0 $0 $0
148388 REL Hughes Lane MOS SWITCH Lexington Plant to Paris 69 kV line $0 $0 $0 $0 $0
150844 REL Madisonville Loop MOS SWITCH Nebo 228-644 to Earlington North 202-614 69 kV line $0 $0 $0 $0 $0
151792 REL Radcliff MOS SWITCH-AUTO Rogersville to Vine Grove 69 kV $97,813 $0 $0 $0 $0
151793 REL Esserville MOS SWITCH-AUTO Bond to Dorchester 69 kV line $97,946 $0 $0 $0 $0
151794 REL Elizabethtown Tap MOS SWITCH-AUTO Elizabethtown to Elizabethtown (2) 69 kV $585,621 $0 $0 $0 $0
151796 REL Joyland 69kV MOS SWITCH-MOTOR OPERATED Lexington Plant to Paris 69 kV line $97,851 $0 $0 $0 $0
151797 REL Campbellsville Ind MOS SWITCH-AUTO Lebanon to Taylor County 69 kV line $73,472 $0 $0 $0 $0
151798 REL Harlan 557 MOS SWITCH-MOTOR OPERATED Harlan Y to Evarts to Pocket 69 kV $97,851 $0 $0 $0 $0
151799 REL Somerset 3 MOS SWITCH-MOTOR OPERATED Ellinu to Somerset North 69 kV 96-624 $390,561 $0 $0 $0 $0
151800 REL Elizabethtown 4 MOS SWITCH-AUTO Elizabethtown to Hodgenville EKPC 69 kV interconnection $0 $493,778 $0 $0 $0
151801 REL Dayholt Tap MOS SWITCH-MOTOR OPERATED Harlan Y to Rocky Branch 69 kV line $0 $98,931 $0 $0 $0
151802 REL Dayholt Tap LFI SWITCH-MOTOR OPERATED Harlan Y to Rocky Branch 69 kV line $0 $24,757 $0 $0 $0
151803 REL Corydon-Calhoun LFI SWITCH-MOTOR OPERATED Corydon to Calhoun 69 kV line $0 $9,891 $0 $0 $0
151804 REL Morehead West MOS SWITCH-AUTO Rodburn to Farmers 69 kV line $0 $74,252 $0 $0 $0
151805 REL Calhoun MOS SWITCH-MOTOR OPERATED Earlington North to Green River Steel 69 kV line $0 $247,295 $0 $0 $0
151806 REL Caron MOS SWITCH-AUTO London to Sweet Hollow 69 kV line $0 $98,958 $0 $0 $0
151807 REL Corbin 2 795-625 MOS SWITCH-MOTOR OPERATED Farley to Sweet Hollow 69 kV line $0 $74,468 $0 $0 $0
151808 REL Corbin 1 844-605 MOS SWITCH-AUTO Farley to Sweet Hollow 69 kV line $0 $74,468 $0 $0 $0
151810 REL Ashland MOS SWITCH-MOTOR OPERATED Race Street to UK Medical Center 69 kV line $0 $98,958 $0 $0 $0
151812 REL Lemons Mill MOS SWITCH-AUTO Adams to Haefling 69 kV line $0 $444,770 $0 $0 $0
151813 REL MR Sterling MOS SWITCH-AUTO Spencer Road to Clark County 69 kV line $0 $247,295 $0 $0 $0
153030 REL Line Mod-In Line Breakers BREAKER $0 $250,000 $0 $0 $0
153068 REL Lebanon 5 Motor Add SWITCH-MOTOR OPERATED Lebanon to Taylor County 69 kV line $100,196 $0 $0 $0 $0
153073 REL Cynthia 5 MOS 569-605 SWITCH-MOTOR OPERATED Millersburg to Renaker EKPC 69 kV interconnection $75,000 $0 $0 $0 $0
153076 REL Girdler MOS Add SWITCH-AUTO Bimble to London 69 kV $0 $100,000 $0 $0 $0
<table>
<thead>
<tr>
<th>Project Description</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adams to Cynthiana Switching 69 kV line</td>
<td>$0</td>
</tr>
<tr>
<td>Somerset EKPC to Russell County EKPC 69 kV interconnections</td>
<td>$0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$9,583,185</strong></td>
</tr>
</tbody>
</table>
Q-404. Regarding Table 5 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-404.

<table>
<thead>
<tr>
<th></th>
<th></th>
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<tr>
<td>Switch Maintenance</td>
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<tr>
<td>Line Sectionalizing</td>
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</table>
Question No. 405

Responding Witness: Lonnie E. Bellar

Q-405. Regarding Table 6 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-405.

<table>
<thead>
<tr>
<th>LG&amp;E System Integrity and Modernization (MM USD)</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Defective Line Equipment</td>
<td>3.8</td>
<td>4.1</td>
<td>3.3</td>
<td>7.7</td>
<td>5.8</td>
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<tr>
<td>Replace Line Switches</td>
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<td>0.0</td>
</tr>
<tr>
<td>Replace Overhead Lines</td>
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<td>0.0</td>
</tr>
<tr>
<td>Improve P&amp;C Systems</td>
<td>0.1</td>
<td>0.3</td>
<td>0.8</td>
<td>0.9</td>
<td>0.8</td>
</tr>
<tr>
<td>Replace Circuit Breakers</td>
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<td>0.2</td>
<td>2.3</td>
<td>2.9</td>
</tr>
<tr>
<td>Replace Underground Lines</td>
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<td>0.0</td>
<td>0.0</td>
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<td>Replace Subs Insulators</td>
<td>0.0</td>
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<td>0.0</td>
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<td>0.4</td>
</tr>
<tr>
<td>Corrosion Protection</td>
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<td>0.0</td>
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<td>0.0</td>
</tr>
<tr>
<td>Replace Substation Line Arresters</td>
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</tr>
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<td>Replace Coupling Capacitors</td>
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<td><strong>Total LG&amp;E System Integrity and Modernization</strong></td>
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<td><strong>7.0</strong></td>
<td><strong>4.3</strong></td>
<td><strong>10.9</strong></td>
<td><strong>10.0</strong></td>
</tr>
</tbody>
</table>
LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General’s Initial Data Requests for Information
Dated January 11, 2017

Question No. 406

Responding Witness: Lonnie E. Bellar

Q-406. Regarding Line Sectionalizing Program Cost table at the bottom of page 27 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-406.

<table>
<thead>
<tr>
<th>LG&amp;E Line Sectionalizing Program Cost (MM USD)</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Install Auto Line Sectionalizing</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>
Q-407. Regarding Table 7 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-407. The Company did not track this information in 2012 for these categories, nor did it track insulators in 2013. The table below provides the available data for both LG&E and KU.

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cross Arms</td>
<td>33</td>
<td>175</td>
<td>136</td>
<td>116</td>
</tr>
<tr>
<td>Insulators</td>
<td>0</td>
<td>246</td>
<td>90</td>
<td>120</td>
</tr>
<tr>
<td>Poles</td>
<td>487</td>
<td>315</td>
<td>572</td>
<td>654</td>
</tr>
</tbody>
</table>
Q-408. Regarding Overhead Line Replacement Program Cost table at the top of page 33 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-408.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Overhead Lines</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>
LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General’s Initial Data Requests for Information
Dated January 11, 2017

Question No. 409

Responding Witness: Lonnie E. Bellar

Q-409. Regarding Table 8 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-409.

<table>
<thead>
<tr>
<th>LG&amp;E Total Protection &amp; Controls Program Cost (MM USD)</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Control Houses</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Replace Relay Panels</td>
<td>0.1</td>
<td>0.2</td>
<td>0.8</td>
<td>0.9</td>
<td>0.6</td>
</tr>
<tr>
<td>Replace RTUs</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Replace PLCs</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Install DFRs</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Replace Battery sets</td>
<td>0.0</td>
<td>0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Total Protection &amp; Controls</strong></td>
<td><strong>0.1</strong></td>
<td><strong>0.3</strong></td>
<td><strong>0.8</strong></td>
<td><strong>0.9</strong></td>
<td><strong>0.8</strong></td>
</tr>
</tbody>
</table>
Q-410. Regarding Breaker Replacement Program Cost table at the top of page 41 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-410.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Circuit Breakers</td>
<td>0.6</td>
<td>2.6</td>
<td>0.2</td>
<td>2.3</td>
<td>2.9</td>
</tr>
</tbody>
</table>
Q-411.  Regarding Underground Line Replacement Program Cost table at the top of page 44 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-411.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Underground Lines</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>
Q-412. Regarding Switch Replacement Program Cost table at the top of page 45 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-412.

<table>
<thead>
<tr>
<th>LG&amp;E Switch Replacement Program Cost (MM USD)</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Line Switches</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>
Q-413. Regarding Substation Insulator Replacement Program Cost table at the bottom of page 45 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-413.

<table>
<thead>
<tr>
<th>LG&amp;E Substation Insulator Replacement Program Cost (MM USD)</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Subs Insulators</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.4</td>
</tr>
</tbody>
</table>
Q-414. Regarding Substation Arrester Replacement Program Cost table at the bottom of page 47 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-414.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Substation Line Arresters</td>
<td>0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>
Q-415. Regarding Coupling Capacitor Replacement Program Cost table on page 48 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-415.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Coupling Capacitors</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
</tr>
</tbody>
</table>
Q-416. Regarding the discussion of Investment selection methodology in Section 3 of Exhibit PWT-5, provide:

a. The detailed results of the DA evaluation against existing portfolio of system reliability and resiliency capital programs.

b. Data from this evaluation in electronic format, preferably Excel.

A-416. 

a. The reference to the discussion on page 41 of the Testimony of Paul W. Thompson is specific to the use of AIS to evaluate the benefits of DA with respect to other reliability and resiliency programs. DA was first incorporated into AIS along with other system improvement projects in the 2016 Business Plan (developed 1 Qtr. 2015). The original DA program scope, timing, investment and valuation against other reliability and resiliency programs have evolved since that time but analysis continues to show DA is the most cost effective program to obtain the desired improvements in reliability. See the response to Question No. 399(a)

b. See the response to Question No. 399(a).
Question No. 417

Responding Witness: John K. Wolfe

Q-417. Regarding Table 3 of Exhibit PWT-5 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-417. The Distribution Automation program was initiated in 2016. There were no Distribution Automation program investments prior to 2016.
Q-418. Regarding the telecommunications consultant engagement discussed in section 5.1.3 of Exhibit PWT-5 provide all written reports, findings and conclusions.

A-418. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.
LKS Solution Alternatives

Update from 10/19/16:
Added CVR Counts Updates and
Adjusted the FTE Cost Allocations

Distribution Automation and AMI
Communications Medium Study
LKS Current State Summary

- Current FLISR DA Locations
  - 294 Installed Locations Planned for Phase 1 communications
  - 14 additional reclosers with comm service already – Not included in Pricing
  - 1597 Total Points Being Deployed - All are reclosers

- AMI Collectors
  - Used in Lexington and Louisville for an L&G pilot program
  - Private and cellular backhaul
    - Assume substation locations could be DA backhaul locations
  - Additional 154 Collectors to be added for a statewide system over the next 3 years
    - 106 Collectors requiring Backhaul Communications

- CVR Program Requiring Communications
  - Up to 619 Feeders in Program Identified
  - Capacitor Banks in the feeders – 3 Each Feeder
  - LTC’s in subs – Some subs without adequate communications backhaul today
  - AMI bellwether meters will provide end of line voltage monitoring
Phase 1 Build (294 Locations – Reclosers in Place)
Phase 2 Build (420 Locations)
Phase 3 Build (381 Locations)
Total Buildout Requirements for DA Locations

• 1,597 total FLISR DA locations identified and geo-located

• FLISR DA Roadmap Counts for Cost Estimates
  – IDA – 2017 + Master locations (if Applicable)
  – Remaining Phase 1 Remotes – 2018
  – Phase 2 Remotes – 2019
  – Phase 3 Remotes – 2020
  – Phase 4 Remotes – 2021
AMI Collectors Needing Communications
106 AMI Locations out of 153 Needed Comms

PSE located AMI collectors based on:

- Not in Substations (Feeders or Raw Land)
- In Substations without adequate communications
  - Leased 4-wire
  - MAS
  - Narrowband radio
CVR Locations Needing Communications
Solution Alternatives Assumptions
Backhaul Requirements - Devices

• 1,597 total geo-located FLISR DA reclosers
  – Located in Feeders

• 106 geo-located AMI Collectors
  – Located in Feeders and at Substations with inadequate backhaul communications today

• 1,953 CVR capacitors and substation LTC’s
  – Feeders and subs geo-located
  – 3 capacitors per feeder circuit (1,857 capacitors)
  – 96 substations require communications for the LTC’s
FLISR Bandwidth Assumptions

- Using Suggested Report-by-Exception from Last Meeting:
  - DNP3 Class 0-3 Integrity Polls every 15 Minutes
  - Report-by-Exception Events
  - 5 Events per day (worst case)
  - 5 Control Commands per day

<table>
<thead>
<tr>
<th>Inputs:</th>
<th>Ethernet</th>
<th>Seconds Between Polls</th>
<th>Times Per Day</th>
<th>Bytes Per Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integrity Poll Request Length</td>
<td>81</td>
<td>900</td>
<td>96</td>
<td>7776</td>
</tr>
<tr>
<td>Integrity Poll Response Length</td>
<td>253</td>
<td>900</td>
<td>96</td>
<td>24288</td>
</tr>
<tr>
<td>Integrity Poll TCP Acknowledge</td>
<td>60</td>
<td>900</td>
<td>96</td>
<td>5760</td>
</tr>
<tr>
<td>Report By Exception Events</td>
<td>1000</td>
<td>17280</td>
<td>5</td>
<td>5000</td>
</tr>
<tr>
<td>SCADA Confirm</td>
<td>80</td>
<td>17280</td>
<td>5</td>
<td>400</td>
</tr>
<tr>
<td>Event TCP Acknowledge</td>
<td>60</td>
<td>17280</td>
<td>5</td>
<td>300</td>
</tr>
<tr>
<td>Control Select</td>
<td>80</td>
<td>17280</td>
<td>5</td>
<td>400</td>
</tr>
<tr>
<td>Control Confirm</td>
<td>81</td>
<td>17280</td>
<td>5</td>
<td>405</td>
</tr>
<tr>
<td>Control Write</td>
<td>80</td>
<td>17280</td>
<td>5</td>
<td>400</td>
</tr>
<tr>
<td>Control Confirm</td>
<td>81</td>
<td>17280</td>
<td>5</td>
<td>405</td>
</tr>
<tr>
<td>Control TCP Acknowledge</td>
<td>60</td>
<td>17280</td>
<td>5</td>
<td>300</td>
</tr>
</tbody>
</table>

Total Bytes Per day 45434
MegaBytes Per day 0.05
MegaBytes Per Month (assuming 30 day month) 1.36
AMI Bandwidth Assumptions

- **L&G Assumptions:**
  - 200 Bytes of data per Meter
  - 10,000 Meters per Collector
  - 15 Minute Intervals (worst case)
  - 1% Bellwether Meters

### PSE Recommended Scan Rates for AMI (AMS) Collectors

<table>
<thead>
<tr>
<th>Inputs:</th>
<th>Ethernet</th>
<th>Seconds Between Polls</th>
<th>Times Per Day</th>
<th>Bytes Per Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bytes Per Meter</td>
<td>414 Bytes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters Per Collector</td>
<td>10000 Bytes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15 Minute Meter Reads</td>
<td></td>
<td>14440</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Total Bytes Per Reads</td>
<td>7038000 Bytes</td>
<td></td>
<td>6</td>
<td>42228000 Bytes</td>
</tr>
<tr>
<td>Reads TCP Acknowledge/meter</td>
<td>60 Bytes</td>
<td>14440</td>
<td>6</td>
<td>3600000 Bytes</td>
</tr>
<tr>
<td>Total Meter TCP Acknowledges</td>
<td>600000 Bytes</td>
<td></td>
<td>6</td>
<td>3600000 Bytes</td>
</tr>
<tr>
<td>Bell Weather Responses X 100 Meters</td>
<td>4420 Bytes</td>
<td>300</td>
<td>288</td>
<td>1272960 Bytes</td>
</tr>
<tr>
<td>Bell Weather TCP Confirms X 100</td>
<td>6000 Bytes</td>
<td>300</td>
<td>288</td>
<td>1728000 Bytes</td>
</tr>
<tr>
<td>Individual Meter Read Poll</td>
<td>102 Bytes</td>
<td>17280</td>
<td>5</td>
<td>510</td>
</tr>
<tr>
<td>Individual Meter Read Response</td>
<td>44.2 Bytes</td>
<td>17280</td>
<td>5</td>
<td>221</td>
</tr>
<tr>
<td>Individual Meter Read TCP Response</td>
<td>60 Bytes</td>
<td>17280</td>
<td>5</td>
<td>300</td>
</tr>
<tr>
<td>Meter/Module Firmware Updates 1/Year</td>
<td>50000 Bytes/Meter</td>
<td>3100</td>
<td>27.9</td>
<td>1393548 Bytes</td>
</tr>
</tbody>
</table>

**Total Bytes Per day**: 50223359

**MegaBytes Per day**: 50.22

**MegaBytes Per Month** (Assuming 30 days per month): 1.51

**GB/Mo**: 1.51
CVR Bandwidth Assumptions

- **PSE Assumptions:**
  - DNP3 Class 0-3 Integrity Polls every 5 Minutes
  - 5 Voltage Adjustment Control Commands per day
  - Operational 24/7/365

<table>
<thead>
<tr>
<th>Inputs:</th>
<th>Ethernet</th>
<th>Seconds Between Polls</th>
<th>Times Per Day</th>
<th>Bytes Per Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integrity Poll Request Length</td>
<td>81 Bytes</td>
<td>300</td>
<td>288</td>
<td>23328</td>
</tr>
<tr>
<td>Integrity Poll Response Length</td>
<td>253 Bytes</td>
<td>300</td>
<td>288</td>
<td>72864</td>
</tr>
<tr>
<td>Integrity Poll TCP Acknowledge</td>
<td>60 Bytes</td>
<td>300</td>
<td>288</td>
<td>17280</td>
</tr>
<tr>
<td>Control Select</td>
<td>80 Bytes</td>
<td>17280</td>
<td>5</td>
<td>400</td>
</tr>
<tr>
<td>Control Confirm</td>
<td>81 Bytes</td>
<td>17280</td>
<td>5</td>
<td>405</td>
</tr>
<tr>
<td>Control Write</td>
<td>80 Bytes</td>
<td>17280</td>
<td>5</td>
<td>400</td>
</tr>
<tr>
<td>Control Confirm</td>
<td>81 Bytes</td>
<td>17280</td>
<td>5</td>
<td>405</td>
</tr>
<tr>
<td>Control TCP Acknowledge</td>
<td>60 Bytes</td>
<td>17280</td>
<td>5</td>
<td>300</td>
</tr>
<tr>
<td>Total Bytes Per day</td>
<td></td>
<td></td>
<td></td>
<td>115382</td>
</tr>
<tr>
<td>MegaBytes Per day</td>
<td></td>
<td></td>
<td></td>
<td>0.12</td>
</tr>
<tr>
<td>MegaBytes Per Month (assuming 30 day month)</td>
<td></td>
<td></td>
<td></td>
<td>3.46</td>
</tr>
</tbody>
</table>
Solution Alternatives Attributes Review
Reviewed Attributes Definitions & Terminology

• Cost – Budgetary Costs relative to the other solutions

• Availability – How well is the telecommunications channel available for use.
  – Measure -Yes or No

• Latency – Round trip delay for enquiry / response
  – Measure – Less latency indicates higher quality
  – Latency Jitter – Variance in time round trip delay for enquiry / response
    • Measure – Less indicates higher quality

• Quality of Service (QoS) / priority – Capable of being prioritized
  – Measure –Supported or Not Supported

• Bandwidth – Maximum data rate of the channel available for use
  – Measure –Large, Medium, Narrow
  – In the case of leased services, while available bandwidth is large, there is a cost for using it. Analysis is based on costed service plans

• Security – Cybersecurity capability relative to other solutions

• Protocol Support – Ability to support desired device protocol
  – Measure -Yes or No
Solutions Alternatives Reviewed

• Leased LTE Cellular Service Through a Major Cellular Provider
• 700 MHz Private WiMAX Radio System
• Hybrid of Leased LTE Cellular and Private WiMAX
• Private LTE Network through AT&T/Nokia Partnership
• Capitalized Leased Cellular using Conxx Solution
Cost Model Requirements

• Design Costs

• Network Management System

• PSE Assumed Periodic Maintenance:
  – Field Personnel visit each location every 2 years
    • Antenna sweeps
    • Battery maintenance and replacement
    • Physical maintenance and clean up
    • Visual Inspection
    • Record data and take pictures
  – 1.0 FTE – Engineering and IT support
    • PSE assumed 2.0 FTE for engineering support of the private LTE solution due to the complexity of maintaining a LTE network.
Leased Cellular Service
Leased Cell Data Service

• Leased M2M plan from major cellular provider

• LKS to purchase and install cellular modems in reclosers, AMI collectors and CVR capacitors and LTC’s control cabinets

• Solution costs included external antennas and cables to help in signal acquisition

• Many vendors currently producing quality devices
  – Features range from basic to advanced
  – GE MDS, Cal Amp, Cisco, Sierra Wireless, etc.
Basic Cell Modem
• PSE used this Modem for Pricing
Leased Cellular Attributes Review

10 Year Costs
AT&T Recently Provided Costs

Typical Plan Approach:

<table>
<thead>
<tr>
<th></th>
<th>Devices</th>
<th>Monthly Usage/Device</th>
<th>Monthly Fee/Device</th>
<th>Monthly Pooled Data</th>
<th>Total Monthly Fees</th>
</tr>
</thead>
<tbody>
<tr>
<td>FLISR</td>
<td>1600</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

Confidential Information Redacted
## Verizon Provided Pooled Costs

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Component 1</td>
<td>Cost A</td>
<td>$100</td>
</tr>
<tr>
<td>Component 2</td>
<td>Cost B</td>
<td>$200</td>
</tr>
<tr>
<td>Component 3</td>
<td>Cost C</td>
<td>$300</td>
</tr>
</tbody>
</table>

**Confidential Information Redacted**
## CapEx Budgetary Costs For Cellular

### Estimated Site-Based Installed Capital Costs per Site

<table>
<thead>
<tr>
<th>Cal Amp End Modem at End-Point</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cellular Modem Radio</td>
<td>$ 800</td>
</tr>
<tr>
<td>Line, Antenna, Surge Suppression</td>
<td>$ 500</td>
</tr>
<tr>
<td>Third-party Installation</td>
<td>$ 750</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 2,050</strong></td>
</tr>
</tbody>
</table>

Installed in Control Cabinet
## Budgetary Costs For Cellular – AMI and CVR Included

### Data Inputs

<table>
<thead>
<tr>
<th>Data Points</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Remote Installed Costs</td>
<td>$2,050</td>
</tr>
<tr>
<td>Maintenance Percentage of Hardware Installed</td>
<td>2.0%</td>
</tr>
<tr>
<td>SIM Card Cost</td>
<td>$-</td>
</tr>
<tr>
<td>Maintenance Hours Per Year per FTE (90%)</td>
<td>1,872</td>
</tr>
<tr>
<td>Days Per Year FTE Working</td>
<td>234</td>
</tr>
<tr>
<td>Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)</td>
<td>$85.00</td>
</tr>
<tr>
<td>FTE Cost Per Year for Field Maintenance</td>
<td>$159,120.00</td>
</tr>
<tr>
<td>Field Locations Visited per day per FTE Employee</td>
<td>2</td>
</tr>
<tr>
<td>Periodic Maintenance Locations per year per FTE Employee</td>
<td>468</td>
</tr>
<tr>
<td>Visit All Locations Within this Many Years</td>
<td>2</td>
</tr>
<tr>
<td>Engineering (IT Department) Fully Loaded Costs per Hour</td>
<td>$100.00</td>
</tr>
<tr>
<td>Engineering FTE Required Per Year for Ongoing Support</td>
<td>$1.00</td>
</tr>
</tbody>
</table>

### CapEx Initial Investment

<table>
<thead>
<tr>
<th>Data Points</th>
<th>Values</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>1,597</td>
<td></td>
</tr>
<tr>
<td>AMI (AMS) Collectors by Year</td>
<td>126</td>
<td></td>
</tr>
<tr>
<td>CVR Locations By Year</td>
<td>1,953</td>
<td></td>
</tr>
<tr>
<td>FLISR Remote Locations Modem Installed Costs</td>
<td>$61,500</td>
<td></td>
</tr>
<tr>
<td>AMI (AMS) Model Collectors Installed Costs</td>
<td>$73,800</td>
<td></td>
</tr>
<tr>
<td>CVR Remote Modem Installed Costs</td>
<td>$801,550</td>
<td></td>
</tr>
<tr>
<td>Network Management System</td>
<td>$50,000</td>
<td></td>
</tr>
<tr>
<td>System Design</td>
<td>$40,000</td>
<td></td>
</tr>
<tr>
<td>Total CapEx Costs</td>
<td>$1,026,850</td>
<td></td>
</tr>
</tbody>
</table>

### OpEx Costs (Excluding Initial Capital Investments)

<table>
<thead>
<tr>
<th>Data Points</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintenance Materials</td>
<td>$0.00</td>
</tr>
<tr>
<td>Remote Site Visited Each Year</td>
<td>$19,737</td>
</tr>
<tr>
<td>IT Engineering Labor Costs Per Year</td>
<td>$127,200</td>
</tr>
<tr>
<td>Field Maintenance Labor Costs Per Year For Remote Locations</td>
<td>$77,690</td>
</tr>
<tr>
<td>Total OpEx Costs</td>
<td>$1,784,800</td>
</tr>
<tr>
<td>Total System Costs</td>
<td>$15,528,000</td>
</tr>
</tbody>
</table>

### Annual Costs Over 10 Year Period

<table>
<thead>
<tr>
<th>Years</th>
<th>Total CapEx Costs</th>
<th>Total OpEx Costs</th>
<th>Total System Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>$7,585,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>$7,944,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 Year</td>
<td>$15,528,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rounded 10 Year Total Cost</td>
<td>$15,528,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost Per End Point over 10 Year Period</td>
<td>$4,247</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Confidential Information Redacted
Leased LTE Cellular Attributes Review

Availability
Availability – Public LTE Networks - Pros

- All LTE network operators have central monitoring and dispatch for their networks.
- A dedicated staff monitors degradation and outages 24/7/365. Dispatch criteria differs, but substantial outages are typically addressed quickly.
- LTE operators have trained maintenance and repair staff available to address outages.
- As the site density increases, a single site outage has less impact on overall network availability, especially during non-peak traffic.
- Network availability has steadily improved, especially with the largest nationwide carriers.
Availability – Public LTE Networks - Cons

• Unknown Coverage for all locations. Utility does not control coverage capability.

• LTE networks have grown large, and staffing has likely not increased in proportion. Therefore, response time appears to be increasing. However, the increased site density has allowed this without noticeable outage times (nearby site can cover while staff are dispatched)

• The risk which is most concerning with a public LTE network is a large, widespread outage typically due to a natural events such as weather. Deliberate damage (sabotage) is also a concern, but events have been rare.

• In the case of a natural disaster, sites may be unavailable for extended periods of time.

• The most likely risks are extended power outages due to damaged power distribution lines, physical damage to the building from flooding, or damage to the antenna system from high winds or ice storms.
Latency
Latency – Public LTE networks

• A public LTE network is shared with many users. The traffic tends to ebb & flow during certain times of the day, thus the latency fluctuates based on users.

• The utility does not control the latency of a public cellular network.

• PSE has conducted lab experiments and studies in the past to measure latency at various times through several 24-hour periods (see example on next slide).
Cellular Latency by Time of Day

- Cellular latency can vary from 100ms to > 600ms
- Acceptable for DNP, but not for IEC-61850 GOOSE or SMV
Leased LTE Cellular Attributes Review

Quality of Service (QoS)/Prioritization
Leased Cellular Quality of Service (QoS)/Latency

- Public networks cannot guarantee any given level of service. Many subscribers are competing for a finite amount of bandwidth and will have the same priority by law.

- Public networks suffer degradation during periods of high traffic. Events such as emergencies (car wrecks, fires, etc.) have been known to cause network blockage ranging from several minutes to several hours.

- Natural disasters such as weather, earthquake, etc. can cause outages and degradation for hours, days, or even longer in severe cases.
Leased LTE Cellular Attributes Review

Bandwidth Availability
Leased Cellular Bandwidth

• Bandwidth was defined previously as “Maximum data rate of the channel available for use”

• In the case of public LTE networks, bandwidth is considered “High” (~38Mbps 5MHz channel), but it is shared with many users.

• Our definition of leased cellular bandwidth is tied to the data plans chosen in the cost sections:
  – FLISR Reclosers and CVR Locations = 5 MB/Month Plan (<1 kbps per device)
    • Limited by using unsolicited report by exception
  – AMI Collectors = 2 GB/Month Plan (400 kbps per device)

• Extra bandwidth is available, but it comes at a monthly service cost penalty
  – Pooled data will help limit penalty
  – Note: Careful review of unnecessary SCADA traffic will need to be enforced to stay within data plans
Leased LTE Cellular Attributes Review

Cybersecurity
Security – Public Networks

• Since devices on a public network are visible to a wide area, there is more exposure to third-party “hacker” threats than private networks
  – End-to-end secure encryption is highly recommended for both private and public networks

• While it is possible to secure assets connected to a public network, more diligence is often required to ensure nothing is left exposed.

• See the Protocol Review of Security recommendations for all communications solutions alternatives
Leased LTE Cellular Attributes Review

Protocol Support
Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.
Full Spectrum 700 MHz Private Radio Network
Full Spectrum “FullMax” Point-to-Multipoint

- Full Spectrum is a smaller company located in Silicon Valley focused on WiMAX communications for electrical utilities in the lower, privately-owned frequency bands
  - Most WiMAX products are at 2.4 or 5.8 GHz spectrum
  - 3 bits/hertz payload capacity

- Full Spectrum has been in business for about 10 years
  - Venture capital company
  - Soon to listed on the NASDAQ with a $15 M IPO
  - Has had some recent big wins at 700 MHz
    - Great River Energy in MN is one
Full Spectrum Point-to-Multipoint

Basic Configuration:

- 700 MHz Upper A Block
- Use WiMAX sub-carriers (AMC) to create 4 logical sub-channels across 2 MHz
- Symmetrical TDD configuration
  - 4 Sectored towers can use same spectrum at all towers
  - 1.4 Mbps/Sector/Tower
  - 5.6 Mbps per Tower
  - TDD provides predictable latency
    - Some latency and speed compromises
Full Spectrum Point-to-Multipoint

Capacity Considerations:

• FullMAX uses adaptive modulation to maximize capacity on a per link / per direction basis

• Weakest link does not "drag down" all other links in the same sector

• Modulation / coding scheme determined by signal quality (CINR) for downlink and uplink

• Dynamic adaptation to accommodate fading

• TDD configuration allows for flexible use of bandwidth (symbols)
  – Symmetrical - equal downlink : uplink
  – Asymmetrical - higher capacity in downlink
  – Reverse asymmetrical - higher capacity in uplink (typical for utility applications, e.g. AMI backhaul)
Access Spectrum 700 MHz Information

The Upper 700 MHz A Block

Block Size and License Areas

- The Upper 700 MHz A Block is a 1 MHz paired (2 MHz total) block of spectrum licensed by the FCC in 52 geographic areas called Major Economic Areas (MEAs).

Spectrum Location

- The Upper 700 MHz A Block is located between the Upper 700 MHz C and D Blocks.

- Access Spectrum owns the 700 MHz A1 Block
- Can be purchased for private use as a 2 MHz pair for $0.75 per MHz/population
700 MHz WiMAX Attributes Review

10 Year Costs
Private Full Spectrum – Cost Assumptions

• Fiber to every site not connected to LKS backbone today
  – 74 miles of fiber at $25k/mile

• Three new 150’ towers will be required
  – $80k/tower
  – Outside, environmentally-controlled cabinet used at towers

• LKS can purchase the spectrum only in the counties used and not the whole state of KY
### Private Full Spectrum Network – Costs

#### Full Spectrum Remote End-Point

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Spectrum Radio</td>
<td>$1,000</td>
</tr>
<tr>
<td>Line, Antenna, Surge Suppression</td>
<td>$500</td>
</tr>
<tr>
<td>Third-party Installation</td>
<td>$750</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$2,250</strong></td>
</tr>
</tbody>
</table>

#### 700 MHz Frequency Purchase

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost Per MHz/Population</th>
<th>MHz of Spectrum</th>
<th>Population</th>
<th>Price of Spectrum $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Per MHz/Population</td>
<td>$0.75</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MHz of Spectrum</td>
<td></td>
<td>2.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Population</td>
<td></td>
<td>5,358,037</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Price of Spectrum</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>$8,037,056</strong></td>
</tr>
</tbody>
</table>

#### Private Full Spectrum Build Costs

<table>
<thead>
<tr>
<th>Component</th>
<th>Count</th>
<th>Price</th>
<th>Extended Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Antenna</td>
<td>4</td>
<td>$300</td>
<td>$1,200</td>
</tr>
<tr>
<td>Coax</td>
<td>800</td>
<td>$8.00</td>
<td>$6,400</td>
</tr>
<tr>
<td>Connectors</td>
<td>8</td>
<td>$50</td>
<td>$400</td>
</tr>
<tr>
<td>Cabinet with Power System</td>
<td>1</td>
<td>$4,000</td>
<td>$4,000</td>
</tr>
<tr>
<td>Master Radios</td>
<td>4</td>
<td>$12,000</td>
<td>$48,000</td>
</tr>
<tr>
<td>Installation</td>
<td>1</td>
<td>$10,000</td>
<td>$10,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>$70,000</strong></td>
</tr>
</tbody>
</table>
### Input Data

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>150' Tower Cost Per Tower</td>
<td>$80,000</td>
</tr>
<tr>
<td>Full Spectrum 4 Sector Tower Site Equipment Cost Per Site</td>
<td>$70,000</td>
</tr>
<tr>
<td>Remote Location Installed Costs</td>
<td>$2,250</td>
</tr>
<tr>
<td>Maintenance Percentage of Hardware Installed Cost</td>
<td>1.0%</td>
</tr>
<tr>
<td>SIM Card Cost</td>
<td>-$</td>
</tr>
<tr>
<td>Fiber Cost Per Mile</td>
<td>$25,000.00</td>
</tr>
<tr>
<td>Maintenance Hours Per Year per FTE (90%)</td>
<td>1,872</td>
</tr>
<tr>
<td>Days Per Year FTE Working</td>
<td>234</td>
</tr>
<tr>
<td>Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)</td>
<td>$85.00</td>
</tr>
<tr>
<td>FTE Cost Per Year for Field Maintenance</td>
<td>$159,120.00</td>
</tr>
<tr>
<td>Field Locations Visited per day per FTE Employee</td>
<td>2</td>
</tr>
<tr>
<td>Periodic Maintenance Locations per year per FTE Employee</td>
<td>468</td>
</tr>
<tr>
<td>Visit All Locations Within this Many Years</td>
<td>2</td>
</tr>
<tr>
<td>Engineering (IT Department) Fully Loaded Costs per Hour</td>
<td>$100.00</td>
</tr>
<tr>
<td>Engineering FTE Required Per Year for Ongoing Support</td>
<td>1.00</td>
</tr>
</tbody>
</table>

### CapEx Initial Investment

<table>
<thead>
<tr>
<th>Description</th>
<th>Year 0</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
<th>Year 5</th>
<th>Year 6</th>
<th>Year 7</th>
<th>Year 8</th>
<th>Year 9</th>
<th>Year 10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>$6,750</td>
<td>$59,400</td>
<td>$94,500</td>
<td>$857,250</td>
<td>$1,129,500</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$3,593,250</td>
</tr>
<tr>
<td>AMI (AMS) Collectors - by Year</td>
<td>$81,000</td>
<td>$78,750</td>
<td>$78,750</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$238,500</td>
</tr>
<tr>
<td>CVR Locations By Year</td>
<td>$879,750</td>
<td>$879,750</td>
<td>$879,750</td>
<td>$877,500</td>
<td>$877,500</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$4,394,250</td>
</tr>
<tr>
<td>Access Spectrum 700 MHz Purchase</td>
<td>8,037,056</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Network Management System</td>
<td>50,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tower Site Full Spectrum Installations</td>
<td>0</td>
<td>80,000</td>
<td>80,000</td>
<td>80,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>240,000</td>
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<td>Tower Build Counts</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,050,000</td>
</tr>
<tr>
<td>Fiber Miles Built</td>
<td>25</td>
<td>25</td>
<td>24</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>49</td>
</tr>
</tbody>
</table>

### OpEx Costs (Excluding Initial Capital Investments)

<table>
<thead>
<tr>
<th>Description</th>
<th>Year 0</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
<th>Year 5</th>
<th>Year 6</th>
<th>Year 7</th>
<th>Year 8</th>
<th>Year 9</th>
<th>Year 10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintenance Materials</td>
<td>$500</td>
<td>$21,283</td>
<td>$47,308</td>
<td>$73,343</td>
<td>$90,690</td>
<td>$110,760</td>
<td>$110,760</td>
<td>$110,760</td>
<td>$110,760</td>
<td>$110,760</td>
<td>$786,923</td>
<td></td>
</tr>
<tr>
<td>Remote Site Visited Each Year</td>
<td>0</td>
<td>236</td>
<td>589</td>
<td>1,017</td>
<td>1,402</td>
<td>1,848</td>
<td>1,848</td>
<td>1,848</td>
<td>1,848</td>
<td>1,848</td>
<td>12,483</td>
<td></td>
</tr>
<tr>
<td>FTE Needed for Field Work (Comm or OVS)</td>
<td>0.50</td>
<td>1.26</td>
<td>2.17</td>
<td>3.00</td>
<td>3.95</td>
<td>3.95</td>
<td>3.95</td>
<td>3.95</td>
<td>3.95</td>
<td>3.95</td>
<td>50,000</td>
<td></td>
</tr>
<tr>
<td>Field Maintenance Labor Costs Per Year for Remote Locations</td>
<td>$80,240</td>
<td>$200,090</td>
<td>$345,610</td>
<td>$476,680</td>
<td>$628,320</td>
<td>$628,320</td>
<td>$628,320</td>
<td>$628,320</td>
<td>$628,320</td>
<td>$628,320</td>
<td>$4,244,220</td>
<td></td>
</tr>
</tbody>
</table>

### Total CapEx Costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Year 0</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
<th>Year 5</th>
<th>Year 6</th>
<th>Year 7</th>
<th>Year 8</th>
<th>Year 9</th>
<th>Year 10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total CapEx Costs over 10 Year Period</td>
<td>$21,288,000</td>
<td>$4,970,950</td>
<td>$3,581,223</td>
<td>$3,118,098</td>
<td>$2,346,960</td>
<td>$2,761,070</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$28,191,198</td>
</tr>
<tr>
<td>Total OpEx Costs over 10 Year Period</td>
<td>$6,903,000</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td></td>
</tr>
<tr>
<td>Rounded 10 Year Total Cost</td>
<td>$28,191,000</td>
<td>$6,903,000</td>
<td>$3,581,223</td>
<td>$3,118,098</td>
<td>$2,346,960</td>
<td>$2,761,070</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td>$926,280</td>
<td></td>
</tr>
<tr>
<td>Cost Per End Point over 10 Year Period</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td>$7,711</td>
<td></td>
</tr>
</tbody>
</table>
700 MHz WiMAX Attributes Review

Availability
Availability – Private (utility owned & managed) Networks

• By owning, operating, and maintaining their own private network dedicated to their needs, the utility can set their own service availability objectives.

• However, this comes at a cost. In order to approach the availability and time to restore of the large common carriers, the communications system must be carefully monitored and maintained.

• A department with trained staff in sufficient numbers to complete routine maintenance programs and address outages in a timely manner is required.

• The costs associated with this include salary, training, instruments, and vehicles. Typically, 24/7/365 coverage is required to match the common carrier service level.
Availability – Private (utility owned & managed) Networks

• Large and mid-sized utilities often have a telecommunications or SCADA group in place already. This group could be expanded, cross-trained, and tasked with the operation and maintenance of the private network.

• The cost of providing this level of service is often prohibitive for small to mid-sized utilities.
Latency
Latency of 700 MHz Private WiMAX System

• Very stable and predictable latency for this network once all end points installed on network.
  – Links use adaptive modulation to change the individual links during times of interference which can cause the overall latency to vary

• Uses Time Division Duplexing (TDD) to create time slots for each device on the network

• Eliminates collisions in point-to-multipoint radio system
  – At the expense of throughput
Quality of Service (QoS)/Prioritization
Quality of Service (QoS) Support

Most equipment used in private communication networks can be configured with levels of priority and QoS. Additionally, the utility devices will not be competing with traffic other than their own. This is a distinct advantage of private communication networks.

- The Full Spectrum WiMAX product has several levels of QoS to choose from as part of the configuration.
Bandwidth Availability
# FullMax Point-to-Multipoint Speeds

Frame Capacity / Throughput for basic configuration:
The following table shows the projected raw data throughput for a single sector using 1/4 of the 2 MHz in a single sector.

<table>
<thead>
<tr>
<th>FEC Code</th>
<th>Repetition</th>
<th>Modulation Coding Scheme</th>
<th>Downlink Frame (bytes)</th>
<th>Uplink Frame (bytes)</th>
<th>Downlink Throughput (kbps)</th>
<th>Uplink Throughput (kbps)</th>
<th>Aggregate Throughput (kbps)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>2</td>
<td>QPSK 1/2</td>
<td>120</td>
<td>123</td>
<td>77</td>
<td>79</td>
<td>156</td>
</tr>
<tr>
<td>0</td>
<td>1</td>
<td>QPSK 1/2</td>
<td>240</td>
<td>246</td>
<td>154</td>
<td>157</td>
<td>311</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>QPSK 3/4</td>
<td>360</td>
<td>369</td>
<td>230</td>
<td>236</td>
<td>467</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>16 QAM 1/2</td>
<td>480</td>
<td>492</td>
<td>307</td>
<td>315</td>
<td>622</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>16 QAM 3/4</td>
<td>720</td>
<td>738</td>
<td>462</td>
<td>472</td>
<td>933</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>64 QAM 1/2</td>
<td>720</td>
<td>738</td>
<td>461</td>
<td>472</td>
<td>933</td>
</tr>
<tr>
<td>5</td>
<td>1</td>
<td>64 QAM 2/3</td>
<td>960</td>
<td>984</td>
<td>614</td>
<td>630</td>
<td>1244</td>
</tr>
<tr>
<td>6</td>
<td>1</td>
<td>64 QAM 3/4</td>
<td>1080</td>
<td>1107</td>
<td>691</td>
<td>708</td>
<td>1399</td>
</tr>
</tbody>
</table>
Private 700 MHz WiMAX Bandwidth

• Bandwidth was defined previously as “Maximum data rate of the channel available for use”

• The previous table reflects speeds capable in one master radio sector.
  – PSE’s analysis assumed 16 QAM ¾ modulation would be available on average for the end points
  – Equates to 933 kbps of throughout
  – Can be allocated to more up or down link speeds
  – In Metro areas, assumes 1 AMI collector per master radio sector
  – In Metro areas, assumes no more than 100 FLISR or CVR sites per master radio sector
  – Metro areas would require 500-600 kbps of uplink bandwidth

• Sufficient bandwidth across the service territory
Private 700 MHz WiMAX Attributes Review

Cybersecurity
Security – Private 700 MHz WiMAX

- A private network is inherently more secure than a public network, since the owner controls who gets access.

- Stolen equipment and physical security is still a threat. Private networks are more secure, but still require attention to detail to prevent a security breach.

- Even private networks can be compromised by determined individuals.

- See the Protocol Review of Security recommendations for all communications solutions alternatives.
Protocol Support
Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.
Full Spectrum 700 MHz Hybrid Private Radio Network in High Density Areas & Cellular for Lower Density Area
“FullMax” Point-to-Multipoint in Urban Areas with Cellular in Rural Areas

• The density of the FLISR DA point locations is much greater in the Louisville & Lexington metropolitan areas
  – 77% located in Louisville and Lexington metropolitan areas

• PSE included equally dispersed 2600 CVR locations the same as the FLISR DA locations
  – 77% within Louisville and Lexington metropolitan areas

• AMI collector locations were mapped via Geo-located list
  – Some substations were “unknown” for comms – Included needing comms

• A 700 MHz FullMax Full Spectrum system could be deployed with a modest amount of sites that would cover a significant number of DA FLISR and CVR Locations

• The CAPEX cost associated with this would reduce the OPEX recurring cost of cellular data charges

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Conceptual RF propagation 700 MHz FullMax

• RF Propagation Study Assumptions:
  – Use only six existing towers
  – Assumed antenna centerline near top of structure
  – Available tower loading and space is assumed; it would need to be verified prior to a detailed design
  – Remote antennas located 20’ above ground level
  – Remote antenna is omnidirectional, mounted in an optimal location and antenna gain is sufficient to offset feedline losses and minor mounting obstruction losses
    • In other words, antenna gain, feed line losses, and any local obstruction losses are assumed to equal zero. This is a conservative approach to modelling.
  – Used 25 km geo-fencing ring around the tower locations for backhaul counts for FLISR and AMI Collectors
700 MHz Site Density for Reclosers
700 MHz Density for CVR Locations
Hybrid WiMAX/Cellular Attributes Review

10-Year Costs
## Hybrid 700 MHz and Cellular Costs

### Full Spectrum Remote End-Point

<table>
<thead>
<tr>
<th>Component</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Spectrum Radio</td>
<td>$1,000</td>
</tr>
<tr>
<td>Line, Antenna, Surge Suppression</td>
<td>$500</td>
</tr>
<tr>
<td>Third-party Installation</td>
<td>$750</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$2,250</td>
</tr>
</tbody>
</table>

### Cal Amp End Modem at End-Point

<table>
<thead>
<tr>
<th>Component</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cellular Modem Radio</td>
<td>$800</td>
</tr>
<tr>
<td>Line, Antenna, Surge Suppression</td>
<td>$500</td>
</tr>
<tr>
<td>Third-party Installation</td>
<td>$750</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$2,050</td>
</tr>
</tbody>
</table>

### 700 MHz Frequency Purchase

<table>
<thead>
<tr>
<th>Component</th>
<th>Count</th>
<th>Price</th>
<th>Extended Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Antenna</td>
<td>4</td>
<td>$300</td>
<td>$1,200</td>
</tr>
<tr>
<td>Coax</td>
<td>800</td>
<td>$8.00</td>
<td>$6,400</td>
</tr>
<tr>
<td>Connectors</td>
<td>8</td>
<td>$50</td>
<td>$400</td>
</tr>
<tr>
<td>Cabinet with Power System</td>
<td>1</td>
<td>$4,000</td>
<td>$4,000</td>
</tr>
<tr>
<td>Master Radio</td>
<td>4</td>
<td>$12,000</td>
<td>$48,000</td>
</tr>
<tr>
<td>Installation</td>
<td>1</td>
<td>$10,000</td>
<td>$10,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>$70,000</strong></td>
</tr>
</tbody>
</table>
Hybrid 700 MHz and Cellular Costs

Input Data

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost Per Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Spectrum 4 Sector Tower Site Equipment Cost</td>
<td>$70,000</td>
</tr>
<tr>
<td>Full Spectrum Remote Location Installed Cost</td>
<td>$2,250</td>
</tr>
<tr>
<td>Cellular Remote Location Installed Cost</td>
<td>$2,050</td>
</tr>
<tr>
<td>Maintenance Percentage of Hardware Installed Cost</td>
<td>1.5%</td>
</tr>
<tr>
<td>SIM Card Cost</td>
<td>-</td>
</tr>
<tr>
<td>Maintenance Hours Per Year per FTE (90%)</td>
<td>1,872</td>
</tr>
<tr>
<td>Days Per Year FTE Working</td>
<td>234</td>
</tr>
<tr>
<td>Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)</td>
<td>$85.00</td>
</tr>
<tr>
<td>Hourly Rate for FTE Field Maintenance</td>
<td>$159,120.00</td>
</tr>
<tr>
<td>Field Locations Visited per day per FTE Employee</td>
<td>2</td>
</tr>
<tr>
<td>Periodic Maintenance Locations per year per FTE Employee</td>
<td>468</td>
</tr>
<tr>
<td>Engineering (IT Department) Fully Loaded Costs per Hour</td>
<td>$100.00</td>
</tr>
<tr>
<td>Engineering FTE Required Per Year for Ongoing Support</td>
<td>1.00</td>
</tr>
</tbody>
</table>

CapEx Costs for Full Spectrum

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost Per Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>FS - FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>$3,113,957</td>
</tr>
<tr>
<td>FS - AMI (AMS) Collectors by Year</td>
<td>$3,263,957</td>
</tr>
<tr>
<td>Cell - FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>$3,113,957</td>
</tr>
<tr>
<td>Cell - AMI (AMS) Collectors by Year</td>
<td>$3,263,957</td>
</tr>
<tr>
<td>Tower Site Full Spectrum Installations</td>
<td>0</td>
</tr>
<tr>
<td>FS - FLISR Remote Locations Modem Installed Costs</td>
<td>$2,769,750</td>
</tr>
<tr>
<td>FS - AMI (AMS) Modem Collectors Installed Costs</td>
<td>$36,000</td>
</tr>
<tr>
<td>FS - CVR Remote Modem Installed Costs</td>
<td>$3,065,750</td>
</tr>
<tr>
<td>Access Spectrum 700 MHz Purchase</td>
<td>$3,113,957</td>
</tr>
</tbody>
</table>

CapEx Costs for Cellular Modems

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost Per Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cell - FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>$3,113,957</td>
</tr>
<tr>
<td>Cell - AMI (AMS) Collectors by Year</td>
<td>$3,263,957</td>
</tr>
<tr>
<td>Cell - CVR Locations By Year</td>
<td>0</td>
</tr>
<tr>
<td>Cell - FLISR Remote Locations Modem Installed Costs</td>
<td>$2,769,750</td>
</tr>
<tr>
<td>Cell - AMI (AMS) Model Collectors Installed Costs</td>
<td>$36,000</td>
</tr>
<tr>
<td>Cell - CVR Remote Modem Installed Costs</td>
<td>$3,065,750</td>
</tr>
<tr>
<td>Access Spectrum 700 MHz Purchase</td>
<td>$3,113,957</td>
</tr>
</tbody>
</table>

Overall System Costs

- Network Management System $50,000
- Design $100,000
- Total CapEx Costs $3,263,957

OpEx Costs (Excluding Initial Capital Investments)

- Maintenance Materials $3,750
- Remote Site Visited Each Year $25,952
- FTE Needed for Field Work (Comm or Ops) $47,681
- Field Maintenance Labor Costs Per Year for Remote Locations $75,475
- IT Engineering Labor Costs Per Year $100,854
- Total OpEx Costs $217,902

Total System Costs $3,481,859

Rounded 10 Year Total Cost $19,495,000

Confidential Information Redacted
Availability
Hybrid WiMAX/Cellular Availability

• 6 Private Sites focus on the bulk of the FLISR and CVR required communication assets
  – Limits the public availability issues to only remote areas
  – Better availability in Metro areas
  – Less network maintenance needs due to the limited number of WiMAX Towers

• Cellular LTE availability is the same in the rural areas
Hybrid WiMAX/Cellular Attributes Review

Latency
Latency of 700 MHz Private WiMAX System

• Very stable and predictable latency for this network once all end points installed on network.
  – Links use adaptive modulation to change the individual links during times of interference which can cause the overall latency to vary

• Uses Time Division Duplexing (TDD) to create time slots for each device on the network

• Eliminates collisions in point-to-multipoint radio system
  – At the expense of throughput
Latency – Public LTE Networks

• A public LTE network is shared with many users. The traffic tends to ebb & flow during certain times of the day, thus the latency fluctuates based on users.

• The utility does not control the latency of a public cellular network
Hybrid WiMAX/Cellular Attributes Review

Quality of Service (QoS)/Prioritization
Most equipment used in private communication networks can be configured with levels of priority and QoS. Additionally, the utility devices will not be competing with traffic other than their own. This is a distinct advantage of private communication networks.

- The Full Spectrum WiMAX product has several levels of QoS to choose from as part of the configuration.
- The cellular network will not have QoS support for the rural areas.
Hybrid WiMAX/Cellular Attributes Review

Bandwidth Availability
Private WiMAX Bandwidth

- Bandwidth was defined previously as “Maximum data rate of the channel available for use”

- The previous table reflects speeds capable in one master radio sector.
  - PSE’s analysis assumed 16 QAM $\frac{3}{4}$ modulation would be available on average for the end points
  - Equates to 933 kbps of throughput
  - Can be allocated to more up or down link speeds
  - In Metro areas assumes 1 AMI collector per master radio sector
  - In Metro areas assumes no more than 100 FLISR or CVR sites per master radio sector
  - Metro areas would require 500-600 kbps of uplink bandwidth
Leased Cellular Bandwidth

• Bandwidth was defined previously as “Maximum data rate of the channel available for use”

• In the case of public LTE networks, bandwidth is considered “High” (~38Mbps 5MHz channel), but it is shared with many users.

• Our definition of leased cellular bandwidth is tied to the data plans chosen in the cost sections:
  – FLISR Reclosers and CVR Locations = 5 MB/Month Plan (<1 kbps per device)
    • Limited by using unsolicited report by exception
  – AMI Collectors = 2 GB/Month Plan (400 kbps per device)

• Extra bandwidth is available, but it comes at a monthly service cost penalty
  – Pooled data will help limit penalty
  – Note: Careful review of unnecessary SCADA traffic will need to be enforced to stay within data plans
Security – Public vs Private Networks

• Since devices on a public network are visible to a wide area, there is more exposure to third-party “hacker” threats.
• A private network is inherently more secure, since the owner controls who gets access.
• Stolen equipment and physical security is still a threat.
• End-to-end secure encryption is highly recommended for both private and public networks.
• While it is possible to secure assets connected to a public network, more diligence is often required to ensure nothing is left exposed.
• Private networks are more secure, but still require attention to detail to prevent a security breach.
• Even private networks can compromised by determined individuals.
• This solution would be a little less secure than a 100% private network.
• See the Protocol Review of Security recommendations for all communications solutions alternatives.
Hybrid WiMAX/Cellular Attributes Review

Protocol Support
Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.
Nokia/AT&T Private Cellular Network

• Spectrum provided by AT&T
  – 2.3 GHz Spectrum
  – 5 MHz Paired Blocks with 1 MHz Guard Bands
  – 3 MHz Up and Down
  – 10 year lease at approximately $0.50/MHz/Population

• LTE network provided by Nokia
  – 3 to 6 Sector Sites
  – 15 km range using directional antennas
    • PSE used 10 km for overlap between sites
  – 11 Mbps/sector
  – Utility owns Network
Typical LTE Site Density
Typical Pole-Mounted Small LTE Site
Antennas and radios are mounted aloft and usually connected by fiber and DC power.

Pad-mounted support equipment in weatherproof cabinets (power & battery plant, networking support equipment)
Private LTE Attributes Review

10-Year Costs
Private LTE Network – Cost Assumptions

• Fiber to every site not connected to LKS backbone today
  – 130 miles of fiber at $25k/mile

• Approximately (59) 150’ towers will be required
  – $80k/tower
  – Outside, environmentally-controlled LTE cabinet used at towers

• Core switch will be $0.5 million

• LKS can lease only the counties used and not the whole state of KY
# Private LTE Network – Costs

## Nokia Modem at End-Point

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Count</th>
<th>Price</th>
<th>Extended Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cellular Modem Radio</td>
<td>1</td>
<td>$1,200</td>
<td>$1,200</td>
</tr>
<tr>
<td>Line, Antenna, Surge Suppression</td>
<td>1</td>
<td>$500</td>
<td>$500</td>
</tr>
<tr>
<td>Third-party Installation</td>
<td>1</td>
<td>$750</td>
<td>$750</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>$2,450</strong></td>
<td></td>
</tr>
</tbody>
</table>

## Frequency 10 Year Lease

<table>
<thead>
<tr>
<th>Cost Description</th>
<th>MHz of Spectrum</th>
<th>Population</th>
<th>Price of Spectrum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Per MHz/Population</td>
<td>$0.50</td>
<td>3,736,406</td>
<td><strong>$11,209,218</strong></td>
</tr>
</tbody>
</table>

## Private LTE Tower Site Build Costs

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Count</th>
<th>Price</th>
<th>Extended Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Antenna</td>
<td>3</td>
<td>$300</td>
<td>$900</td>
</tr>
<tr>
<td>Fiber Cable</td>
<td>200</td>
<td>$0.60</td>
<td>$120</td>
</tr>
<tr>
<td>Fiber Connector</td>
<td>6</td>
<td>$10</td>
<td>$60</td>
</tr>
<tr>
<td>Cabinet with Battery and DC Power System</td>
<td>1</td>
<td>$15,000</td>
<td>$15,000</td>
</tr>
<tr>
<td>Base station</td>
<td>1</td>
<td>$30,000</td>
<td>$30,000</td>
</tr>
<tr>
<td>Installation</td>
<td>1</td>
<td>$50,000</td>
<td>$50,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>$96,080</strong></td>
<td></td>
</tr>
</tbody>
</table>

**Installed in Control Cabinet**
# Private LTE Network – 10-Year Costs

## Data Inputs

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>150' Tower Cost Per Tower</td>
<td>$80,000</td>
</tr>
<tr>
<td>LTE Tower Site Equipment Cost Per Site</td>
<td>$96,080</td>
</tr>
<tr>
<td>Remote Location Installed Costs</td>
<td>$2,450</td>
</tr>
<tr>
<td>Maintenance Percentage of Hardware Installed Cost</td>
<td>1.5%</td>
</tr>
<tr>
<td>SIM Card Cost</td>
<td>$0</td>
</tr>
<tr>
<td>Fiber Cost Per Mile</td>
<td>$25,000</td>
</tr>
<tr>
<td>Maintenance Hours Per Year per FTE (90%)</td>
<td>1,872</td>
</tr>
<tr>
<td>Days Per Year FTE Working</td>
<td>234</td>
</tr>
<tr>
<td>Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)</td>
<td>$85.00</td>
</tr>
<tr>
<td>FTE Cost Per Year for Field Maintenance</td>
<td>$159,120.00</td>
</tr>
<tr>
<td>Field Locations Visited per day per FTE Employee</td>
<td>2</td>
</tr>
<tr>
<td>Periodic Maintenance Locations per year per FTE Employee</td>
<td>468</td>
</tr>
<tr>
<td>Visit All Locations Within this Many Years</td>
<td>2</td>
</tr>
<tr>
<td>Engineering (IT Department) Fully Loaded Costs per Hour</td>
<td>$100.00</td>
</tr>
<tr>
<td>Engineering FTE Required Per Year for Ongoing Support</td>
<td>2.00</td>
</tr>
</tbody>
</table>

## CapEx Initial Investment

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tower Site LTE Installations</td>
<td>$79</td>
</tr>
<tr>
<td>FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>$1,597</td>
</tr>
<tr>
<td>CVR Locations Installed</td>
<td>$1,953</td>
</tr>
<tr>
<td>AMI Collectors Installed</td>
<td>$106</td>
</tr>
<tr>
<td>Tower Build Counts</td>
<td>59</td>
</tr>
<tr>
<td>Fiber Miles Built</td>
<td>130</td>
</tr>
<tr>
<td>Remote Locations Installed Costs</td>
<td></td>
</tr>
<tr>
<td>AT&amp;T Frequency Lease</td>
<td>$11,209,218</td>
</tr>
<tr>
<td>LTE Core Switch and NMS</td>
<td>$500,000</td>
</tr>
<tr>
<td>Tower Builds</td>
<td></td>
</tr>
<tr>
<td>LTE Tower Equipment Builds</td>
<td></td>
</tr>
<tr>
<td>Fiber Backbone Extensions</td>
<td>$3,252,500</td>
</tr>
<tr>
<td>Design</td>
<td>$500,000</td>
</tr>
<tr>
<td>Total CapEx Costs</td>
<td>$14,309,218</td>
</tr>
<tr>
<td>Total CapEx Costs over 10 Year Period</td>
<td>$36,729,000</td>
</tr>
</tbody>
</table>

## OpEx Costs (Excluding Set-up Capital Investments)

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cellular Usage Costs/Month</td>
<td></td>
</tr>
<tr>
<td>Maintenance</td>
<td>$2,777,848</td>
</tr>
<tr>
<td>Remote Site Visited Each Year</td>
<td></td>
</tr>
<tr>
<td>Field Maintenance Labor Costs Per Year for Remote Locations</td>
<td>$4,298,280</td>
</tr>
<tr>
<td>IT Engineering Labor Costs Per Year</td>
<td></td>
</tr>
<tr>
<td>Total OpEx Costs</td>
<td>$10,820,000</td>
</tr>
<tr>
<td>Total System Costs</td>
<td>$47,549,366</td>
</tr>
</tbody>
</table>

## Total Costs

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total CapEx Costs over 10 Year Period</td>
<td>$36,729,000</td>
</tr>
<tr>
<td>Total OpEx Costs over 10 Year Period</td>
<td>$10,820,000</td>
</tr>
<tr>
<td>Rounded 10 Year Total Cost</td>
<td>$47,549,000</td>
</tr>
<tr>
<td>Cost Per End Point over 10 Year Period</td>
<td>$13,006</td>
</tr>
</tbody>
</table>

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Availability
Availability – Private LTE Networks

• By owning, operating and maintaining their own private network dedicated their needs, the utility can set their own service availability objectives.
  – However, it will be harder to build a private LTE network more robust than the public network.

• However, this comes at a cost. In order to approach the availability and time to restore of the large common carriers, the communications system must be carefully monitored and maintained

• A department with trained staff in sufficient numbers to complete routine maintenance programs and address outages in a timely manner is required.

• The costs associated with this include salary, training, instruments and vehicles. Typically, 24/7/365 coverage is required to match the common carrier service level.
Availability – Private LTE Networks

• Large and mid-sized utilities often have a telecommunications or SCADA group in place already. This group could be expanded, cross-trained, and tasked with the operation and maintenance of the private network.

• The cost of providing this level of service is often prohibitive for small to mid-sized utilities.

• A Private LTE network will require a large staff to maintain the system.

• Depending upon design, network resilience can be provided if sites overlap; service could be available from another site during a single site failure scenario.

• Allows the utility to be the “masters of their own destiny” with respect to prioritizing maintenance and restoration activities.

• The spectrum available for a private LTE network is leased. Lease terms unknown, but expected to be 10 years.

Confidential Information
Redacted
Private LTE Network Attributes Review

Latency
Latency of Private LTE Network

• A private LTE network would be extremely robust in bandwidth capability. The utility would be hard pressed to push the bandwidth limits.

• Causes of latency issues include:
  – Propagation delay on the RF link (low if build correctly)
  – Propagation delay on the backhaul
  – Competing for bandwidth for other users

• This means the latency should be:
  – Low due to the lack of competing for the bandwidth
  – Probably better than any other solution alternative
  – Very stable and predictable
Private LTE Network Attributes Review

Quality of Service (QoS)/Prioritization
Quality of Service (QoS) Support

- Most equipment used in private communication networks can be configured with levels of priority and QoS.
- Additionally, the utility devices will not be competing with traffic other than their own.
- This is a distinct advantage of private communication networks.
- QoS capability may not need to be used for this network.
Private LTE Network Attributes Review

Bandwidth Availability
Private LTE Network Bandwidth

- Bandwidth was defined previously as “Maximum data rate of the channel available for use”
- 33 Mbps per sector (assumed 3 sectors per tower)
- A private LTE network would have substantial capacity beyond what is required for DA, and could be used in support of other initiatives:
  - CVR
  - AMI
  - Mobile Workforce Management (MWM)
  - Small Sub SCADA, metering, and video surveillance
  - Many other applications
Private LTE Network Attributes Review

Cybersecurity
Security – Private LTE Network

- A private network is inherently more secure than a public network, since the owner controls who gets access.
- Stolen equipment and physical security is still a threat. Private networks are more secure, but still require attention to detail to prevent a security breach.
- Even private networks can compromised by determined individuals.
- See the Protocol Review of Security recommendations for all communications solutions alternatives.
Protocol Support
Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.
Conxx/Nokia 10-Year Capitalized Cellular Service
Combined Nokia and Conxx

- Conxx – Third-party
- Uses Nokia 7705 router
- Uses universal SIM
  - AT&T and Verizon
- Provided quote for many options. PSE used lowest LTE quote for 300 MB per month for 10 years.
- 10-year hedge on cell costs.

Global Grid Router

The Global Grid Router provides industry-leading IP/MPLS communications capabilities over a common carrier LTE network in a DIN rail-mountable compact form with temperature, electromagnetic, shock and vibration hardening.

The Global Grid Router is ideally suited for deployments in harsh and cramped environments, particularly smart grid distribution and field area automation or rolling rail vehicles’ on-board applications. It is optimized for secure and reliable delivery of mission-critical applications for network operators in utilities, transportation, government and public safety.

Key Bundle Features

- 10 Year Globally Connected
- Ruggedized for vibration, shock, dust, splash & humidity
- Certified 3G/4G/LTE enterprise grade internal router and modem
- Software defined radio supports multiple carriers (Gobi)
- Built-in transient and reverse polarity voltage protection
- Out of Band modem and router management
- 9–36 DC voltage input range
- Integrated temperature sensors
- Active GPS support
Conxx Attributes Review

10-Year Costs
## Budgetary Costs For Conxx CapEx Cellular

**Estimated Site-Based Installed Capital Costs per Site**

<table>
<thead>
<tr>
<th>Global Grid Router (300 MB/Mo) (FLISR/CVR)</th>
<th>Global Grid Router (2 GB/Mo) - AMI</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cabinet and 10 year 300 MB/Mo LTE Service</strong></td>
<td><strong>Cabinet and 10 year 2 GB/Mo LTE Service</strong></td>
</tr>
<tr>
<td>$13,037</td>
<td>$14,693</td>
</tr>
<tr>
<td><strong>Line, Antenna, Surge Suppression</strong></td>
<td><strong>Line, Antenna, Surge Suppression</strong></td>
</tr>
<tr>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td><strong>Third-party Installation</strong></td>
<td><strong>Third-party Installation</strong></td>
</tr>
<tr>
<td>$750</td>
<td>$750</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>Total</strong></td>
</tr>
<tr>
<td>$13,787</td>
<td>$15,443</td>
</tr>
</tbody>
</table>

Global Grid Router Bill of Materials

- GGR Ruggedized Modem - Enterprise Class Mobile 3G / 4G LTE Multi-Band Router NO Wi-Fi
- GGR Ruggedized MPLS Router - Nokia SAR HC
- SAR HC 7705 SAM License
- 3G / 4G LTE 9 dBi Omni-Directional Fixed Mount Outdoor Fiberglass Antenna with mounting bracket
- Cable - Antenna cable 20-Ft
- Cable - GGR Serial Cable (Modem to Router)
- GGR Mounting Bracket
- Dual Power Supplies, 480W, 120-240VAC 1PH, 24-28VDC, 20-17.5A
- GGR NEMA 4 Enclosure
- GGR 10 Year Data SIM (LTE or 3G)
- DIN Rails and Lockable PIN Mounts
- GGR Out of Band Management Module
- GGR Modem Firmware
- GGR IP Addressing
## Budgetary Costs For Conxxx CapEx Cellular

### Input Data

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 MB/Mo Remote Installed Costs</td>
<td>$13,787</td>
</tr>
<tr>
<td>10 GB/Mo Remote Installations</td>
<td>$15,443</td>
</tr>
<tr>
<td>Maintenance Percentage of Hardware Installed Cost</td>
<td>0.5%</td>
</tr>
<tr>
<td>SIM Card Cost</td>
<td>$-</td>
</tr>
<tr>
<td>Maintenance Hours Per Year per FTE (00%)</td>
<td>1,872</td>
</tr>
<tr>
<td>Days Per Year FTE Working</td>
<td>234</td>
</tr>
<tr>
<td>Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)</td>
<td>$85.00</td>
</tr>
<tr>
<td>FTE Cost Per Year for Field Maintenance</td>
<td>$159,129</td>
</tr>
<tr>
<td>Field Locations Visited per day per FTE Employee</td>
<td>2</td>
</tr>
<tr>
<td>Periodic Maintenance Locations per year per FTE Employee</td>
<td>468</td>
</tr>
<tr>
<td>Visit All Locations Within this Many Years</td>
<td>2</td>
</tr>
<tr>
<td>Engineering IT Department - Fully Loaded Costs per Hour</td>
<td>$100.00</td>
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### CapEx Initial Investment

<table>
<thead>
<tr>
<th>Phase</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 MB/Mo - FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>30</td>
<td>264</td>
<td>420</td>
<td>381</td>
<td>502</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,597</td>
</tr>
<tr>
<td>10 GB/Mo - AMI Collectors Installed</td>
<td>36</td>
<td>35</td>
<td>35</td>
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<td>Remote Locations Installed Costs</td>
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### Network Management System

- $50,000

### System Design

- $20,000

### Total CapEx Costs

- $70,000

### OpEx Costs (Excluding Initial Capital Investments)

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
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<tbody>
<tr>
<td>Cellular Usage Costs/Month -</td>
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<tr>
<td>Maintenance Materials</td>
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<tr>
<td>Remote Site Visited Each Year</td>
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<tr>
<td>Field Maintenance Labor Costs Per Year for Remote Locations</td>
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<td>IT Engineering Labor Costs Per Year</td>
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### Total OpEx Costs

<table>
<thead>
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<th>Year</th>
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<tbody>
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<tr>
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<td>$1,061,874</td>
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<tr>
<td></td>
<td>$1,061,874</td>
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<tr>
<td></td>
<td>$1,061,874</td>
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</table>

### Total System Costs

<table>
<thead>
<tr>
<th>Year</th>
<th>Total System Costs</th>
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<td>$12,183,858</td>
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<td>$11,294,302</td>
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<td>$13,061,874</td>
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<tr>
<td></td>
<td>$13,061,874</td>
</tr>
<tr>
<td></td>
<td>$13,061,874</td>
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<tr>
<td></td>
<td>$13,061,874</td>
</tr>
<tr>
<td></td>
<td>$13,061,874</td>
</tr>
</tbody>
</table>

### CapEx Costs over 10 Year Period

- $50,651,000

### OpEx Costs over 10 Year Period

- $7,769,000

### Cost Per End Point over 10 Year Period

- $15,979

### Rounded 10 Year Total Cost

- $58,420,000

### Rounded 10 Year Total Cost

- $58,420,000

### Cost Per End Point over 10 Year Period

- $15,979
Capitalized Leased LTE Cellular Attributes Review

Availability
Availability – Public LTE networks - Pros

- All LTE network operators have central monitoring and dispatch for their networks.
- A dedicated staff monitors degradation and outages 24/7/365. Dispatch criteria differs, but substantial outages are typically addressed quickly.
- LTE operators have trained maintenance and repair staff available to address outages.
- As the site density increases, a single site outage has less impact on overall network availability, especially during non peak traffic.
- Network availability has steadily improved, especially with the largest nationwide carriers.
Availability – Public LTE networks-Cons

• Unknown Coverage for all locations. Utility does not control coverage capability.

• LTE networks have grown large, and staffing has likely not increased in proportion. Therefore, response time appears to be increasing. However, the increased site density has allowed this without noticeable outage times (nearby site can cover while staff are dispatched)

• The risk which is most concerning with a public LTE network is a large, widespread outage typically due to a natural events such as weather. Deliberate damage (sabotage) is also a concern, but events have been rare.

• In the case of a natural disaster, sites may be unavailable for extended periods of time.

• The most likely risks are extended power outage due to damaged power distribution lines, physical damage to the building from flooding, or damage to the antenna system from high winds or ice storms.
Capitalized Leased LTE Cellular Attributes Review

Latency
Latency – Public LTE networks

- A public LTE network is shared with many users. The traffic tends to ebb & flow during certain times of the day, thus the latency fluctuates based on users.

- The utility does not control the latency of a public cellular network.

- PSE has conducted lab experiments and studies in the past to measure latency at various times through several 24 hour periods (see example on next slide).
Cellular Latency by Time of Day

- Cellular latency can vary from 100ms to > 600ms
- Acceptable for DNP, but not for IEC-61850 GOOSE or SMV
Quality of Service (QoS)/Prioritization
Leased Cellular Quality of Service (QoS)/Latency

- Public networks can not guarantee any given level of service. Many subscribers are competing for a finite amount of bandwidth and will have the same priority by law.

- Public networks suffer degradation during period of high traffic. Events such as emergencies (car wrecks, fires, etc.) have been known to cause network blockage ranging form several minutes to several hours

- Natural disasters such as weather, earthquake, etc. can cause outages and degradation for hours, days or even longer in severe cases.
Capitalized Leased LTE Cellular Attributes Review

Bandwidth Availability
Capitalized Leased Cellular Bandwidth

- Bandwidth was defined previously as “Maximum data rate of the channel available for use”

- In the case of public LTE networks, bandwidth is considered “High” (~38Mbps 5MHz channel), but it is shared with many users.

- Our definition of leased cellular bandwidth is tied to the data plans chosen in the cost sections:
  - FLISR Reclosers and CVR Locations = 300 MB/Month Plan (60 kbps per device)
    - Could use polling instead of RBE
  - AMI Collectors = 2 GB/Month Plan (400 kbps per device)

- Extra bandwidth is available, but it comes at a monthly service cost penalty.
  - Pooled data will help limit penalty
  - Note: Careful review of unnecessary SCADA traffic will need to be enforced to stay within data plans
Capitalized Leased LTE Cellular Attributes Review

Cybersecurity
Security – Public Networks

• Since devices on a public network are visible to a wide area, there is more exposure to third party “hacker” threats than private networks.

• End-to-end secure encryption is highly recommended for both private and public networks.

• While it is possible to secure assets connected to a public network, more diligence is often required to ensure nothing is left exposed.

• See the Protocol Review of Security recommendations for all communications solutions alternatives.
Protocol Support
Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.
Solution Alternatives Cost Summary
## Solution Alternatives 10-Year Cost Summary

### Confidential Information
Redacted

### Cost Per Program

<table>
<thead>
<tr>
<th>Technology</th>
<th>Total End Devices Needing Comms</th>
<th>Percentage of End Devices for Cost Allocations</th>
</tr>
</thead>
<tbody>
<tr>
<td>FLISR DA</td>
<td>1597</td>
<td>43.7%</td>
</tr>
<tr>
<td>AMI Collectors</td>
<td>106</td>
<td>2.9%</td>
</tr>
<tr>
<td>CVR Program</td>
<td>1953</td>
<td>53.4%</td>
</tr>
</tbody>
</table>

### Technology Costs

<table>
<thead>
<tr>
<th>Technology</th>
<th>Capital Costs ($1,000's)</th>
<th>Operational Costs ($1,000's)</th>
<th>Total Costs ($1,000's)</th>
<th>Cost per Device</th>
<th>Total Cost Allocation for FLISR ($1,000's)</th>
<th>Total Cost Allocation for AMI Collectors ($1,000's)</th>
<th>Total Cost Allocation for CVR ($1,000's)</th>
</tr>
</thead>
<tbody>
<tr>
<td>700 MHz Full Spectrum</td>
<td>$21,288</td>
<td>$6,903</td>
<td>$28,191</td>
<td>$7,711</td>
<td>$12,314</td>
<td>$817</td>
<td>$15,059</td>
</tr>
<tr>
<td>ConXX - Capitalized Cellular</td>
<td>$50,651</td>
<td>$7,769</td>
<td>$58,420</td>
<td>$15,979</td>
<td>$25,519</td>
<td>$1,694</td>
<td>$31,207</td>
</tr>
</tbody>
</table>

Using a Percentage Allocation based on Number of Remotes Installed in each Program
## Cellular Solution for FLISR DA Only

### Data Inputs

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Remote Installed Costs</td>
<td>$2,050</td>
</tr>
<tr>
<td>Maintenance Percentage of Hardware Installed Cost</td>
<td>2.0%</td>
</tr>
<tr>
<td>SIM Card Cost</td>
<td>-</td>
</tr>
<tr>
<td>Maintenance Hours Per Year per FTE (90%)</td>
<td>1,872</td>
</tr>
<tr>
<td>Days Per Year FTE Working</td>
<td>234</td>
</tr>
<tr>
<td>Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)</td>
<td>$85.00</td>
</tr>
<tr>
<td>FTE Cost Per Year for Field Maintenance</td>
<td>$159,120</td>
</tr>
<tr>
<td>Field Locations Visited per day per FTE Employee</td>
<td>2</td>
</tr>
<tr>
<td>Periodic Maintenance Locations per year per FTE Employee</td>
<td>468</td>
</tr>
<tr>
<td>Visit All Locations Within this Many Years</td>
<td>2</td>
</tr>
<tr>
<td>Engineering (IT Department) Fully Loaded Costs per Hour</td>
<td>$100.00</td>
</tr>
<tr>
<td>Engineering (IT Department) FTE Required Per Year for Ongoing Support</td>
<td>1.00</td>
</tr>
</tbody>
</table>

### CapEx Initial Investment

<table>
<thead>
<tr>
<th>Description</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>FLISR Remotes Installed - By Phase (30 IDA)</td>
<td>30</td>
<td>264</td>
<td>420</td>
<td>381</td>
<td>502</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,597</td>
</tr>
<tr>
<td>FLISR Remote Locations Modem Installed Costs</td>
<td>$61,500</td>
<td>$541,200</td>
<td>$861,000</td>
<td>$781,050</td>
<td>$1,029,100</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$3,273,850</td>
<td></td>
</tr>
<tr>
<td>Network Management System</td>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$50,000</td>
</tr>
<tr>
<td>System Design</td>
<td>$40,000</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$40,000</td>
</tr>
<tr>
<td>Total CapEx Costs</td>
<td>$0</td>
<td>$151,500</td>
<td>$541,200</td>
<td>$861,000</td>
<td>$781,050</td>
<td>$1,029,100</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$3,363,850</td>
</tr>
</tbody>
</table>

### OpEx Costs (Excluding Initial Capital Investments)

| Remote Site Visited Each Year for Maintenance    | 0 | 15 | 147 | 357 | 548 | 799 | 799 | 799 | 799 | 799 | 5,059 |
| FTE Needed for Field Maintenance                  | 0.03 | 0.31 | 0.76 | 1.17 | 1.71 | 1.71 | 1.71 | 1.71 | 1.71 | 1.71 | 5.059 |
| Non-IT Field Maintenance Labor Costs Per Year for Remote Locations | $5,100 | $49,980 | $121,380 | $186,150 | $271,490 | $271,490 | $271,490 | $271,490 | $271,490 | $271,490 | $1,720,060 |
| Total OpEx Costs                                  | $187,390 | $201,601 | $267,517 | $385,491 | $458,121 | $564,294 | $564,294 | $564,294 | $564,294 | $564,294 | $4,302,117 |
| Total System Costs                                | $0 | $339,420 | $742,801 | $1,128,517 | $1,146,541 | $1,487,221 | $564,294 | $564,294 | $564,294 | $564,294 | $7,665,967 |

### Total Costs

- **Total CapEx Costs over 10 Year Period**: $3,364,000
- **Total OpEx Costs over 10 Year Period**: $4,302,000
- **Rounded 10 Year Total Cost**: $7,666,000
- **Cost Per End Point over 10 Year Period**: $4,800

---

**FLISR DA Only Costs**

This Program Absorbs the Engineering and Network Management System Costs plus IT FTE Engineer Costs and 1.71 FTE Field Maintenance.
### Cellular Solution for AMI (AMS) Only

#### Data Inputs

- **Remote Installed Costs**: $2,050
- **Maintenance Percentage of Hardware Installed Cost**: 2.0%
- **SIM Card Cost**: $-
- **Maintenance Hours Per Year per FTE (90%)**: 1,872
- **Days Per Year FTE Working**: 234
- **Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)**: $85.00
- **FTE Cost Per Year for Field Maintenance**: $159,120.00
- **Field Locations Visited per day per FTE Employee**: 2
- **Periodic Maintenance Locations per year per FTE Employee**: 468
- **Visit All Locations Within this Many Years**: 2
- **Engineering (IT Department) Fully Loaded Costs per Hour**: $100.00

#### CapEx Initial Investment

<table>
<thead>
<tr>
<th>YEAR</th>
<th>AMI (AMS) Collectors</th>
<th>AMI (AMS) Model Collectors Installed Costs</th>
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<tbody>
<tr>
<td>0</td>
<td>$73,800</td>
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<tr>
<td>10</td>
<td>$0</td>
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#### Operation Expenses (Excluding Initial Capital Investments)

<table>
<thead>
<tr>
<th>YEAR</th>
<th>Maintenance Materials</th>
<th>Remote Site Visited Each Year for Maintenance</th>
<th>FTE Needed for Field Maintenance</th>
<th>Non-IT Field Maintenance Labor Costs Per Year for Remote Locations</th>
<th>IT Engineering Labor Costs Per Year</th>
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<tbody>
<tr>
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<td>$4,346</td>
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<tr>
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<td>$4,346</td>
<td>0.11</td>
<td>$18,020</td>
<td>$-</td>
</tr>
<tr>
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<td>0.11</td>
<td>$18,020</td>
<td>$-</td>
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<td>0.11</td>
<td>$18,020</td>
<td>$-</td>
</tr>
</tbody>
</table>

#### Total Costs

- **Total CapEx Costs over 10 Year Period**: $217,000
- **Total OpEx Costs over 10 Year Period**: $374,000
- **Rounded 10 Year Total Cost**: $592,000
- **Cost Per End Point over 10 Year Period**: $5,585

### AMI (AMS) Only Costs

**Minimal Maintenance FTE Allocation (0.11 FTE)**

Attachment to Response to AG-1 Question No. 418
Page 138 of 147
Wolfe
## Cellular Solution for CVR Only

### Data Inputs

<table>
<thead>
<tr>
<th>Data Input</th>
<th>Value</th>
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<tr>
<td>Remote Installed Costs</td>
<td>$2,050</td>
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<tr>
<td>Maintenance Percentage of Hardware Installed Cost</td>
<td>2.0%</td>
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<tr>
<td>SIM Card Cost</td>
<td>$ -</td>
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<tr>
<td>Maintenance Hours Per Year per FTE (80%)</td>
<td>1,872</td>
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<tr>
<td>Days Per Year FTE Working</td>
<td>234</td>
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<tr>
<td>Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)</td>
<td>$85.00</td>
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<tr>
<td>FTE Cost Per Year for Field Maintenance</td>
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<tr>
<td>Field Locations Visited per day per FTE Employee</td>
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<tr>
<td>Periodic Maintenance Locations per year per FTE Employee</td>
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<td>Visit All Locations Within this Many Years</td>
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<td>Engineering (IT Department) Fully Loaded Costs per Hour</td>
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### CapEx Initial Investment

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<th>YEAR</th>
<th>CVR Locations By Year</th>
<th>$</th>
<th>CVR Remote Modem Installed Costs</th>
<th>$</th>
<th>Network Management System</th>
<th>$</th>
<th>System Design</th>
<th>$</th>
<th>Total CapEx Costs</th>
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<td></td>
<td>$0</td>
<td></td>
<td>$0</td>
<td></td>
<td>$0</td>
<td></td>
</tr>
</tbody>
</table>

### OpEx Costs (Excluding Initial Capital Investments)

| Maintenance Materials | $16,031 | $32,062 | $48,093 | $64,083 | $80,073 | $80,073 | $80,073 | $80,073 | $80,073 | $560,634 |
| Remote Site Visited Each Year for Maintenance | 0 | 196 | 391 | 597 | 782 | 977 | 977 | 977 | 977 | 6,837 |
| FTE Needed for Field Maintenance | $66,470 | $132,940 | $199,410 | $265,710 | $332,010 | $332,010 | $332,010 | $332,010 | $332,010 | $2,324,580 |

### Total OpEx Costs

| Total System Costs | $0 | $810,934 | $903,015 | $995,095 | $1,085,102 | $1,176,947 | $459,932 | $459,932 | $459,932 | $459,932 |

### CVR Only Costs

**Maintenance FTE Allocation (2.1 FTE)**

**Total CapEx Costs over 10 Year Period**: $4,004,000

**Total OpEx Costs over 10 Year Period**: $3,267,000

**Rounded 10 Year Total Cost**: $7,271,000

**Cost Per End Point over 10 Year Period**: $3,723
**Difference Percentage Allocation and Full Allocation**

<table>
<thead>
<tr>
<th>Program</th>
<th>10 year Total Cost using Percentage Allocation ($1,000's)</th>
<th>10 year Total Cost using Detailed Allocation ($1,000's)</th>
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</thead>
<tbody>
<tr>
<td>FLISR DA</td>
<td>$6,783</td>
<td>$7,666</td>
</tr>
<tr>
<td>AMI (AMS)</td>
<td>$450</td>
<td>$592</td>
</tr>
<tr>
<td>CVR</td>
<td>$8,295</td>
<td>$7,271</td>
</tr>
</tbody>
</table>

- FLISR pays for Engineer FTE, Design Costs and NMS using the Detailed Allocation Method

- The Detailed Allocation Method better Allocates the Cellular Usage Costs since the AMI Collectors require a higher Data Plan
Cost – Public Cellular (LTE) Network

- A public cellular (LTE) network solution would have the lowest CapEx, requiring only the endpoint radio devices, but would have a recurring network access fee OpEx cost.

- This solution has the lowest 10 year overall cost as well.

- Would require the least maintenance, but the service level is dictated by the carrier, with little influence from the utility.

- Difficult to predict future pricing of LTE data, but it has trended downward, and attractive rates are currently available.

- The lifespan of the endpoints purchased today is a concern, but it is expected to be 8 to 10 years before the carriers will discontinue service as technology evolves.

- If LKS feels the carrier would provide acceptable levels of service, PSE recommends this solution be considered, as it is the lowest cost.
Cost – Private WiMAX (Purchased Spectrum)

• The private WiMAX network based 700 MHz network ranked third in cost. This approach would have a CapEx build, with no monthly recurring fees other than maintenance labor.

• This solution provides adequate bandwidth with spectrum that is available for purchase rather than lease. However, the nature of 700 MHz radio propagation will require several sites to cover the low density of endpoints in more rural areas. This drives up the cost substantially to provide coverage over the entire service area.

• If the desire is to have a completely private network, PSE feels this is a viable approach.
Cost – Hybrid Private WiMAX and Public Cellular (LTE) Network

• Since the majority of the endpoints are located within a couple of urban areas, the private WiMAX solution could reach these with a relatively small number of base station sites. If the remaining rural or outlier sites were connected via a public cellular (LTE) network, the cost of a Hybrid, private-public solution becomes attractive.

• The cost of this solution is higher than an all public network solution, but somewhat less expensive than an all-private WiMAX solution. The utility would be able to control the QoS & restoration activities of the private WiMAX portion, while saving the costs of building multiple rural sites to serve only a few endpoints.

• PSE feels this approach presents a good tradeoff between cost and private vs. public networks.
Cost – Private LTE (Leased Spectrum)

• The Private LTE network solution was next highest cost.

• Covering the entire service area with this technology would be costly, with bandwidth capacity well in excess of current needs.

• The RF spectrum for this option is only available as a lease. It is not known if, or under what terms, the lease could be renewed after the initial 10 years period.

• PSE sees this not only as a significant cost, but also as a substantial risk. The entire life cycle of this system could be limited to the 10 year initial spectrum lease, which may not be financially viable.

• PSE does not recommend this solution due to the over capacity of the solutions, the complexity, the spectrum unknowns, and total costs.
Cost – Conxx All CapEx

• The Conxx all CapEx cellular solution is the most expensive.
• While this solution has a fixed CapEx with no recurring OpEx, it would have performance nearly identical to a month to month cellular (LTE) network solution.
• The cost is considered extremely high for the benefit of CapEx.
• PSE does not recommend this solution since the costs do not outweigh the benefits of capitalized cellular.
### Attribute Table Summary

#### Evaluated Communications Technologies

<table>
<thead>
<tr>
<th>Evaluation Attributes</th>
<th>Cellular (4G/LTE)</th>
<th>Conxx Cellular CapEx</th>
<th>Private LTE</th>
<th>Private WiMAX</th>
<th>Hybrid (WiMAX/Cell)</th>
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</thead>
<tbody>
<tr>
<td>Availability</td>
<td>3</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Substantial commitment to maintenance and restoration is required on Private Networks</td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Latency (predictable/consistent)</td>
<td>4</td>
<td>4</td>
<td>1</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Latency of all platforms is expected to be acceptable. Latency of private networks will be more predictable and consistent (less jitter)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Security</td>
<td>3</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>All options can be made secure (end to end encryption) Private networks have less exposure to third party threats</td>
<td></td>
<td></td>
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<tr>
<td>Bandwidth</td>
<td>5</td>
<td>2</td>
<td>1</td>
<td>3</td>
<td>4</td>
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<tr>
<td>Public network has bandwidth, but it has a penalty for overage</td>
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<tr>
<td>Protocol support</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
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<tr>
<td>All options support current protocols (DNP3 recommended)</td>
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<tr>
<td>QoS/prioritization</td>
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<td>5</td>
<td>1</td>
<td>1</td>
<td>2</td>
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<tr>
<td>Public network QOS is typically not supported / guaranteed</td>
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<td>Cost</td>
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<td>5</td>
<td>4</td>
<td>3</td>
<td>2</td>
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</tbody>
</table>

A lower number is considered better than the other solutions

All solutions reviewed meet the minimal technical requirements for LKS deployment
Thank you!

Power System Engineering, Inc.

Charles Plummer
Project Manager

Sarah Genschaw
Project Coordinator/Main Point of Contact

www.powersystem.org
Q-419. Regarding Table 5 of Exhibit PWT-5 identify transformers affected and detailed investment estimates for each identified transformer in the years of the N1DT contingency program.

A-419. Per Table 5 of Exhibit PWT-5 a total of $9,271k (2015-$2,632k; 2016-$6,639k expected) has been spent to date on the program. A description of the projects completed to date can be found in Section 5.2.3 of Exhibit PWT-5. Included in this amount are additional portable transformers, spare transformers and substation equipment to improve response time for outages in areas where the addition of permanent contingency capacity cannot be reasonably accommodated. Future investment shown in Table 5 of Exhibit PWT-5 will be continuously prioritized to maximize the benefit to the number of customers and transformers impacted. A detailed scope of work and estimate for each transformer listed has not been developed at this time. Estimates on the highest priority project(s) are completed annually and the project list is adjusted to integrate with other projects and programs. See Attachment in response to Question 396 (c) for the current project list of the N1DT contingency program.
Q-420. Regarding Exhibit PWT-6 provide the estimated O&M expense vs Expected O&M savings for the each of the years 2017 through 2022.

A-420.

<table>
<thead>
<tr>
<th></th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
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<tbody>
<tr>
<td>O&amp;M Expense</td>
<td>440</td>
<td>1,362</td>
<td>1,470</td>
<td>1,336</td>
<td>1,371</td>
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<tr>
<td>O&amp;M Savings</td>
<td>0</td>
<td>0</td>
<td>50</td>
<td>100</td>
<td>150</td>
<td>180</td>
</tr>
</tbody>
</table>

Note 1: Values shown are totals for LG&E and KU combined.
Note 2: The financial model referenced includes O&M expenses associated with the DMS over the depreciable life of the DMS asset which ends after 2021. The Companies believe this is the reasonable period for the analysis. Annual ongoing O&M expenses modeled beyond 2021 reflect communication costs associated with the SCADA connected reclosers. A financial scenario including escalated ongoing O&M DMS expenses as well as assumed DMS upgrade costs and timing through 2051 was completed. This scenario showed the “do nothing” alternative to be the lowest NPVRR of the alternatives evaluated. The Companies believe this is scenario is based on an unreasonable period for the analysis because of the uncertainties associated with the 30-year IT system assumptions. Recognizing the uncertainty of 30-year IT system related assumptions and noting reliability improvement is the primary objective of the DA program, completion of the DA program remains the recommended alternative based on the justification described in Exhibit PWT-5 of Mr. Thompson’s testimony.
LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General’s Initial Data Requests for Information
Dated January 11, 2017

Question No. 421

Responding Witness: John K. Wolfe

Q-421. Regarding Exhibit PWT-7, page 1, provide background calculation for NPVRR’s in electronic format, preferably Excel, with active cells.

A-421. See the response to PSC 1-54.

Att_KU_PSC_1-54_Exh_PWT-7_-_LGE_DA_Updated_2016_CEM.xlsx
Att_KU_PSC_1-54_Exh_PWT-7_-_KU_DA_Updated_2016_CEM.xlsx
Att_KU_PSC_1-54_Exh_PWT-7_-_DMS_-_Updated_2016_CEM.xlsx
Q-422. Regarding Exhibit PWT-7, page 2, provide:

a. Background calculation for all entries in electronic format, preferably Excel, with active cells.

b. A detailed explanation of all cost savings and assumptions used in deriving cost savings.

A-422.

a. The LGE DA CEM Model was filed December 8th, 2016.
   Att_KU_PSC_1-54_Exh_PWT-7_-LGE_DA_Updated_2016_CEM.xlsx

b. The cost savings are the O&M savings over the depreciable life of the installed assets. The O&M savings were developed by estimating the value of operational efficiency improvements such as the DMS system fault location predictions reducing the time required to locate faults, SCADA connected reclosers eliminating the need for some manual switching operations and SCADA connected reclosers permitting the remote application of caution cards.
Q-423. Regarding Exhibit PWT-7, page 4, provide:

   a. Background calculation for all entries in electronic format, preferably Excel, with active cells.

   b. A detailed explanation of all cost savings and assumptions used in deriving cost savings.

A-423.

   a. The DMS CEM Model was filed December 8th, 2016. Reference:


       Att_KU_PSC_1-54_Exh_PWT-7__DMS__Updated_2016_CEM.xlsx

   b. Cost savings were not included in the DMS CEM calculations.
Q-424. Regarding Exhibit PWT-8, provide:

a. A detailed explanation of all projects.

b. Annual 5-year historic costs for each category from 2012 to 2016.

A-424.


For a detailed explanation of Distribution Automation refer to Paul W. Thompson testimony, Exhibit PWT-5, pages 24-25.

The Volt/Var Optimization “VVO” solution utilizes software and two-way communication with capacitor bank controls, load tap changers, and voltage regulator controls to provide real-time data, used to optimize voltage and power factor based on utility-selected parameters. Among the benefits of using VVO to achieve energy efficiency targets, it requires no change in customer behavior, requires no customer purchases or incentives, benefits all customer classes, and it reduces environmental impact.

For a detailed explanation of Control Houses refer to Paul W. Thompson testimony Exhibit PWT-2, page 34-36.

The Fiber/Telecom projects upgrade communications systems that are used to support substation devices that monitor and control the electric grid and automatically operate switching equipment in response to system conditions.

For a detailed explanation of Relay panels refer to Paul W. Thompson testimony Exhibit PWT-2 pages 36-37.

For a detailed explanation of RTU’s refer to Paul W. Thompson testimony Exhibit PWT-2 pages 37-38.
For a detailed explanation of Switch – Auto refer to Paul W. Thompson testimony Exhibit PWT-2 pages 27-29.

For a detailed explanation of Switch: Motor Operated refer to Paul W. Thompson testimony Exhibit PWT-2 pages 27-29

b. See attached.
Smart Grid Investments
Historical
$000s

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<tr>
<td>Distribution and Customer Services:</td>
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<tr>
<td>Advanced Metering Systems</td>
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<td>Distribution Automation / DMS</td>
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<tr>
<td>AMS Opt-in Program (DSM)</td>
<td>$1,196</td>
<td>$602</td>
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<td>VOLT/VAR Optimization Pilot (Non-DSM)</td>
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<td>Transmission:</td>
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<td>Control Houses</td>
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<td>Fiber/Telecom</td>
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<td>Relay Panels</td>
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<td>$221</td>
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<td>$567</td>
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<td>RTU's</td>
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<td>Switch - Auto</td>
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<tr>
<td>Switch - Motor Operated</td>
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<tr>
<td><strong>Total LG&amp;E</strong></td>
<td>$1,539</td>
<td>$2,493</td>
<td>$1,548</td>
<td>$2,058</td>
<td>$1,374</td>
</tr>
</tbody>
</table>

1/20/2017
Q-425. Regarding AMS benefits discussion beginning on page 24 of the Testimony of John P. Malloy, provide the following information regarding benefits related to enabling better localization and resolution of power outages:

a. All plans, software and communications planning documents related to providing AMS information to distribution and transmission operations.

b. A detailed explanation of how AMS information will be used to localize and resolve power outages including a description of information flow.

A-425.

a. The Company continues to define plans related to providing AMS information to distribution and transmission operations. See Appendix A-2 of Exhibit JPM-1 for an illustrative application architecture.

b. AMS meters are capable of sending power outage alerts to the Company in near-real time, enabling the Company to characterize more quickly outage locations and type. The outage alert would initiate at the electric meter, be communicated over the proposed infrastructure, be received by the AMS head-end software system, then be pushed to the proposed Meter Data Management System (MDMS) where it will then be reported to the Company’s Outage Management System (OMS) to trigger response by Company personnel. The OMS system operates today based on customers calling or texting their outage in to the Company. As the Company receives multiple outage notifications it begins to hone in on the suspected outage source; this is where AMS information is expected to reduce crew time spent identifying outage locations.
Q-426. Regarding the Section 5.5 diagram at the top of page 13 of Exhibit JPM-1 provide the following information:

   a. Detailed description of how information from customer services is transmitted to deployment operations including communication software from AMS to deployment operations to work orders or other field activities.

   b. Detailed description of how information from the meter operations center is transmitted to deployment operations including communication software from AMS to deployment operations to work orders or other field activities.

   c. Describe equipment, personnel, and facilities anticipated at the meter operations center.

A-426.

   a. The diagram at the top of page 13 of Exhibit JPM-1 is meant to be illustrative. The Company continues to plan how information from customer services will be transmitted to deployment operations, but the Company anticipates frequent information exchange via file transfers and other electronic means.

   b. The diagram at the top of page 13 of Exhibit JPM-1 is meant to be illustrative. The Company continues to plan how information from the meter operations center will be transmitted to deployment operations, but the Company anticipates frequent information exchange via file transfers and other electronic means.

   c. The diagram at the top of page 13 of Exhibit JPM-1 is meant to be illustrative. See section 5.5.9 of Exhibit JPM-1 for a description of the metering operations center.
Question No. 427

Responding Witness: John P. Malloy

Q-427.  Regarding discussion in Section 5.5.9 on page 20 of Exhibit JPM-1 describe how the proposed AMS system will communicate with ADA.

   a. Will the AMS system being deployed communicate with the current planned distribution automation?

   b. Explain how proposed AMS equipment is compatible with future ADA.

A-427.

   a. The AMS system being deployed will communicate with planned distribution automation systems.

   b. The proposed AMS communications infrastructure is capable of supporting multiple endpoint devices including, but not limited to, the currently proposed electric meters, gas indices, as well as load-control devices and a number of DA devices that could potentially be explored with future ADA.
Q-428. Regarding discussion in Section 5.7.2 of Exhibit JPM-1 describe how proposed AMS system will communicate with Volt/VAR optimization.

a. Describe the current a Volt/VAR optimization program or system and required AMS compatibility.

b. Describe future Volt/VAR optimization program or system and required AMS compatibility.

A-428.

a. The Companies will conduct a Volt/VAR Optimization pilot project in 2017 to gather data and evaluate the impacts to energy (kWh) and demand (kW) of a VVO system. The pilot project will be conducted at an LG&E substation on one transformer with two circuits. The pilot project will be conducted through the end of 2017.

b. The Companies may expand V VO to additional substations, and AMS data would be utilized as a data input. AMS data can provide approximately a 1% greater reduction in voltage, thus resulting in greater reductions in energy (kWh) and demand (kW) on the distribution circuit.
Q-429. Regarding discussion in Section 5.7.3 of Exhibit JPM-1 describe how proposed AMS system will communicate with FLISR.

   a. Describe the current FLISR capability and required AMS compatibility.

   b. Describe future FLISR capability and required AMS compatibility.

A-429. The Company does not currently have FLISR capability the AMS system has the capability to provide information for fault detection ability in the future.

   a. Companies do not currently have FLISR capability.

   b. FLISR is a module of the DMS software the Companies propose implementing as part of the DA Program. FLISR will identify the location of a fault and determine the optimal switching to safely isolate the fault and restore the most customers. Powerflow analysis is a prerequisite to performing FLISR. Data from AMS will be used by the DMS to assist in Powerflow analysis. If AMS data is not available, the Powerflow analysis is performed using load profiles.
Q-430. Regarding discussion in Section 5.7.3 of Exhibit JPM-1 describe how proposed AMS system will communicate with DERMS.

a. Describe the current DERMS and required AMS compatibility.

b. Describe future DERMS and required AMS compatibility.

A-430. The Company does not have a Distributed Energy Resource Management System.

a. Company does not currently utilize DERMS.

b. Company currently does not have plans to implement DERMS.
Q-431. Regarding the discussion on page 3 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the customer service line ownership initiative.

Q-432. Regarding the discussion about the new gas pipeline in Bullitt County beginning on page 3 of the Testimony of Lonnie E. Bellar, provide the following information:

   a. Maps showing the existing gas distribution system and the existing one-way feed.

   b. Maps showing the proposed new gas pipeline.

   c. Calculations showing the expected distribution pressures without the new pipeline and expected load growth.

   d. Describe gas supplies to the affected customers both before and after the new pipeline.

A-432.

   a. See the response to PSC 2-64(a).

   b. See the response to PSC 2-64(a).

   c. The gas supply for sections of Bullitt County including Mt. Washington, Shepherdsville, the Hwy 480 corridor, Clermont and Boston is supplied almost exclusively by an 8-inch diameter high pressure distribution pipeline (reducing to 6-inches near Clermont) originating from a gas regulation facility supplied by LG&E’s Calvary gas transmission pipeline system in Mt. Washington effectively making the system a one-way, radial feed. The proposed pipeline will improve reliability for the customers supplied by this system by having a second geographically diverse gas supply to the system. Currently up to 9,500 customers could lose service if supply from the 8-inch high pressure distribution pipeline is lost due to third party damage or other reason. This project would provide a second supply to this area of the system mitigating the number of customers losing service. The high pressure distribution pipeline's available capacity has been almost fully utilized leading to the increased reliability concerns, as well as, limiting available capacity for growth in the area.
The high pressure distribution pipeline supplying gas to the system has a 275 psig maximum operating pressure (MAOP). Based upon the analysis of LG&E’s gas system utilizing steady state gas system modeling software, Synergi Gas, completed in 2016 under design criteria without the new pipeline and without the expected load growth the high pressure distribution pipeline has a minimum pressure of approximately 93 psig occurring on the south end of the system in Boston. Normal growth that LG&E is required to serve by tariff over the next 2 years is expected to cause the high pressure distribution pipeline's minimum pressure to be below the system's design criteria.

d. Prior to constructing the proposed new pipeline the gas supply source for the affected customers is supplied almost exclusively by one source, the Mt. Washington high pressure regulator station. The Mt. Washington high pressure regulator station is supplied from a connection with the Calvary transmission pipeline in Mt. Washington.

After the proposed pipeline is constructed the gas system for the customers in this area will have a second supply from the Calvary gas transmission pipeline from an interconnection near the location where the Calvary gas transmission pipeline crosses Highway 480 and ending with an interconnection with the existing 8-inch high pressure distribution pipeline with an expected location between Hwy 480 and Hwy 245.

The proposed pipeline is expected to be completed in the Winter/Spring timeframe in 2019.
Q-433. Regarding the discussion on page 6 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the advanced engine/compressor analyzer technology initiative.

A-433. LG&E utilizes the Windrock Model 6320/PA engine/compressor analyzer system to evaluate the performance and condition of gas compression equipment associated with underground gas storage system. The analyzer identifies poor fuel consumption factors, excessive exhaust factors, ignition system deficiencies, defective fuel injection valves, leaking intake/exhaust valves, defective piston rings, damaged bearings, damaged rod connecting pins, defective water and lube oil pumps, excessive vibration, and engine foundation damages on the engines driving gas compressors. The analyzer also identifies defective unloaders, excessive rod loadings, excessive cylinder liner wear, equipment pulsations, inadequate compressor rod reversals, loose compressor piston nuts, and excessive valve losses on gas compressors. The advanced analyzer system enables identification of engine/compressor performance issues and mechanical problems before costly damages occur and helps avoid unplanned outages impacting reliable gas supply from underground storage.
Question No. 434

Responding Witness: Lonnie E. Bellar

Q-434. Regarding the discussion on page 8 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the Transmission Integrity Management Plan.

A-434. See the response to Question No. 252.
Q-435. Regarding the discussion on page 8 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the Distribution Integrity Management Plan.

A-435. See the response to Question No. 250.
Response to Question No. 436

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General’s Initial Data Requests for Information
Dated January 11, 2017

Question No. 436

Responding Witness: Lonnie E. Bellar

Q-436. Regarding the discussion on page 18 of the Testimony of Lonnie E. Bellar, provide a detailed explanation, including anticipated annual work activities and associated costs, of why the first three years of the gas service line replacement program will cost $10 – 11 million annually and the last 12 years will cost approximately $4.5 – 7 million annually. Explanation should include the workplan and the rationale for front loading the program.

A-436. The accelerated rate of replacement in the first 3 years allows for a better transition of the current GLT Program contract work force and helps management of the resources for future work. It will also allow an opportunity to evaluate the project after this time frame to measure impact & success and if adjustments need to be made to the remaining program plan. The table below provides detail on work activity and costs. Note that the testimony stating spend in 2018-2020 would be $10-$11 million annually should be $9-$10 million annually.

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<th>Costs Per Year</th>
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<td>$100,860</td>
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</table>
Q-437. Regarding the discussion on page 18 of the Testimony of Lonnie E. Bellar, provide a map of LG&E’s gas transmission system and illustrate where the natural gas transmission pipeline segments being replaced are located as well as marked up to show the HCAs, Class 3 areas, Class 4 areas, and the MCAs.

A-437. See attached. The information in the attachment is confidential and is being provided under seal pursuant to a petition for confidential protection.
The entire attachment is Confidential and provided separately under seal.
Q-438. Regarding the discussion on page 35 of the Testimony of Robert M. Conroy, explain why LG&E is not seeking a CPCN for volt/var resources.

A-438. The Commission stated in its final order in Case No. 2012-00428, which was its most recent case concerning smart-grid standards, “With regard to CPCNs, the Commission finds it appropriate for jurisdictional electric utilities to obtain CPCNs for major AMR or AMI meter investments and distribution grid investments for DA, SCADA or volt/var resources.”\(^7\) LG&E does not believe its planned volt/VAR deployment is of sufficient scope to be “major” or otherwise require a CPCN; rather, it is an ordinary extension of its existing distribution system in the ordinary course of business that will not create wasteful duplication of plant, equipment, property, or facilities, or conflict with the existing certificates or service of other utilities, and will not involve sufficient capital outlay to materially affect the existing financial condition of LG&E.

\(^7\) In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies, Case No. 2012-00428, Order at 11 (Apr. 13, 2016).
Q-439. Regarding the discussion on page 39 of the Testimony of Robert M. Conroy requesting a deviation from the quarterly meter reading requirement describe how LG&E proposes to make sure that meter reads from an AMS meter are properly assigned to the address of the customer. The description should include procedures in place to assure proper meter assignment as well as the process a customer would take if readings appear inappropriately assigned to an address.

A-439. While the mechanism by which meter reads are reported, over-the-air versus a manual read, is changing with the proposed AMS solution, the method by which the Company maintains customer records and assigned meters largely remains unchanged. Company’s SAP Customer Care System (CCS) will remain the billing system so the process of assigning a meter read to an account will also remain.

Robust processes will be established and maintained to ensure meters are initially assigned to the proper address at the time of AMS meter installation. If a meter were to be removed and installed elsewhere, the AMS meters are capable of sending alerts when conditions indicating potential tampering has occurred. As a final level of security, meter numbers as well as current register readings are printed clearly on the face of the meter and the assigned meter is communicated to the customer each month on their bill. If a customer suspects readings are being inappropriately assigned to an address, they can follow existing procedures to request a meter re-read. Additionally, AMS will enable Company agents to ping and read meters in near real-time allowing them to tell customers what the current reading is and enabling immediate confirmation by the customer.
Q-440. Regarding the response to PSC 1-12, provide the following:


b. Latest 10-year plan for replacing key components in each power station.

c. Latest Transmission Expansion Plan.

d. Last 5 annual electric distribution plans.

e. Last 5 annual gas system plans.

A-440.

a. See the response to Question No. 296.

b. See attached.

c. See the response to Question No. 390.

d. For each of the last five years Electric Distribution Operations (EDO) has used the Asset Investment Strategy (AIS) decision-support model to compare the portfolio of diverse distribution capacity, resiliency and reliability projects to develop a five year Business Plan. The construction plan varies year to year based on load growth/reduction, changes in reliability needs and evolving programs to address system resiliency. See attached summaries for 2013-2017.

e. See attached.
<table>
<thead>
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<td>95,634,210</td>
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Electric Distribution Operations Capital Business Plan
High Level Summary
Updated 8/26/16

EDO Budget Process
The Electric Distribution Operations (EDO) business plan consists of five strategic categories: Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous. Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual routine work and equipment purchases where such work cannot be defined in advance. Work is typically driven by short cycle, high volume and often customer driven work requests and storm restoration. Blanket funding is trended from historical actual expenses, volumetric trends, and local economic indicators and is adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, public works relocations, operation center driven reliability and enhancement work, and capital repairs or replacement of failed or damaged equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model and ranked using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program (PITP), Aging Infrastructure (AI) programs, Reliability Initiatives, Capacity Enhancements and property are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value. A technical review team of subject matter experts from various functional areas of EDO reviews and validates the project metrics for each project before projects are prioritized by AIS. The final plan is developed following reviews by EDO Directors and the VP, EDO and adjusted as necessary to address funding for key initiatives and strategies.

1. Connect New Customer Category

The Connect New Customer category largely consists of blanket projects spanning across the plan to cover the ongoing cost of extending electric facilities to serve new customers (or load). Equipment costs such as distribution poles, pad mount transformers and conductors also contribute to the cost for serving new customers (or load). Known major projects to serve new loads such as substation improvements or major circuit work for a single customer are identified separately, but do not occur in the plan every year. Funding for this category includes $67.7M in 2017, approximately a 3.5% ($2.3M) increase from the 2017 amount in the 2016 Business Plan ($65.3M). The variance is due in part to the addition of two large, unplanned LG&E network vault projects associated with the OMNI hotel ($902k), a new vault for the Homewood Suites ($250k) and an incremental need above the 2016 BP in 2017 to complete a substation transformer addition at Toyota South Substation ($300k).

There is an approximate 5% escalation for transformers across the plan. LG&E blanket escalation factors were assumed at 5% (accounting for growth and material/labor increases) and KU escalation assumed at 3% (accounting for growth and material/labor increases). The escalation factors are used in conjunction with historical spend trends, volumetric data, and local economic indicators as a means to forecasting future blanket needs. Major impacts and higher growth rates in the Louisville area have been realized which has been validated through economic data. LKE has seen a significant increase in New Business work requests from 2015 to 2016, especially in the LG&E area. KU as a whole has seen a slight increase in economic development which has been factored into the budget proposal. In total, New Business work requests have increased by 8% from 2015 to 2016 across LKE which is indicative of an increase in New Business activity.

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<td>72,632</td>
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2. **Enhance the Network Category**

The Enhance the Network category includes, blankets, major and minor system improvements required to serve growing load and to enhance the reliability, safety and/or durability of the system. Blanket funding for mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) is also included in this category. All enhancement work is further subdivided below into the categories of Enhancements to Meet Demand, Enhancements for Reliability, Mandated Relocations, and Customer Requested Projects.

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<tr>
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<tr>
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<td>29,655</td>
<td>36,768</td>
<td>38,621</td>
<td>42,958</td>
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**Enhancements to Meet Demand**

This category specifically addresses current loading issues or expected overloads, capacity additions for new load or contingency, expansion of SCADA, and other non-reliability system enhancements. This group of projects varies every year from the previously year’s BP targets due to varying needs and priorities for capacity enhancements. A late addition to the plan in 2017 was necessary to serve an unplanned large new load (Corbin US Steel, $981k-2017) and increased funding for a Substation enhancement initiative (LG&E SMAC). Additional details of the Enhancements to Meet Demand subcategory are shown below.

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<tr>
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<td>36,768</td>
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<td>Total Enhancements to Meet Demand</td>
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<td>29,655</td>
<td>36,768</td>
<td>38,621</td>
<td>42,958</td>
</tr>
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</table>

- **System Enhancement Blankets**
  This item includes blanket funding at each distribution operations center to cover necessary, but currently undefined non-new business distribution system enhancements required each year. Funding is based on historical spend levels and starts at $2.3M in 2017 and is escalated approximately 3% across the plan.

- **Major Substation and Circuit Work Projects**
  Large, generally multiyear substation/circuit work projects are planned so that they can be completed in the year when the asset is forecasted to reach 95% - 100% of its "normal" seasonal operating limit including known or potential new loads. Also included are other enhancement projects that have demonstrated value. The forecasted load of large substation capacity enhancements projects is based on a 10-year non-coincidental substation load forecast which is updated annually and includes known new loads. Projects can also be placed in the plan when substations and circuits are at risk of exceeding their "emergency" operating limits under extreme weather events (such as the Polar Vortex of 2014 and Artic Blast of 2015) or where projects have substantial reliability benefits. The number of major new projects varies across the plan due to expected load growth (from the forecast) and/or expected system improvement benefits. Projects in the outer years of the plan may be adjusted forward or backward in future business plans based on actual load growth, funding
Attachment to Response to AG-1 Question No. 440
dAtt 1

John K. Wolfe

limits and the need to fund other more critical needs that develop in future years. This category also includes a late funding expansion for one major substation enhancement initiative to accelerate work on the Substation Monitoring and Control (SMAC) initiative. This project enhances the ability to control relays remotely at LG&E SCADA enabled stations reducing the OPEX costs associated with sending a Substation Operator to the station for manual operation. 2016 BP funding for SMAC of approximately $220k/year has been increased to $770k-2017, $1197k-2018 and $1410-2019 in an effort to accelerate completion of the program for LG&E in 3 years and recognize the associated operational savings. Another late addition to the plan was the second year of an approximately $1M project added to 2017 to complete a substation project at Corbin US Steel due to unexpected new load growth.

A list of major projects through the first three years is shown below:

<table>
<thead>
<tr>
<th>Project Name</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>Project Name</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSP American Ave Okt 0008 Distribution Step Downs</td>
<td>185</td>
<td></td>
<td></td>
<td>DSP Oxford 2 Distribution</td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSP American Ave Okt 0008 Switchgear</td>
<td>105</td>
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<td></td>
<td>DSP Oxford 2 Substation</td>
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<tr>
<td>DSP Black Branch Road Circuit 2477-Elizabethtown Circuit 2462</td>
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<td></td>
<td>DSP Paris 819-2 substation breaker addition</td>
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<tr>
<td>DSP Buena Vista Upgrade</td>
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<td>750</td>
<td></td>
<td>DSP Paris Circuit 805 circuit addition</td>
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<td></td>
<td></td>
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<tr>
<td>DSP Corbin Steel distribution</td>
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<td></td>
<td></td>
<td>DSP Peaynes Mill Road Substation Distribution &amp; Exit Feeders</td>
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<td></td>
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<tr>
<td>DSP Corbin US Steel Substation</td>
<td>966</td>
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<td></td>
<td>DSP Peaynes Mill Road Substation Project-Versailles</td>
<td>2101</td>
<td>2900</td>
<td></td>
</tr>
<tr>
<td>DSP Delaplan 1 Okt 0401 Distribution</td>
<td>120</td>
<td></td>
<td></td>
<td>DSP Pennington Gap Distribution</td>
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<td></td>
</tr>
<tr>
<td>DSP Fairview 12kV Circuit Addition Project</td>
<td>123</td>
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<td></td>
<td>DSP Pennington Gap Substation</td>
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<td></td>
<td></td>
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<tr>
<td>DSP Gene Substation (2018-2019)</td>
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<td></td>
<td>DSP Pepper Pike 138-12kV substation</td>
<td>2300</td>
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<tr>
<td>DSP Gene Substation Circuit Work (2018-2019)</td>
<td>380</td>
<td></td>
<td></td>
<td>DSP Radcliff South Circuit 2470 Re-conductor Project</td>
<td>147</td>
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<tr>
<td>DSP Georgetown 12kV 2 Distribution</td>
<td>500</td>
<td></td>
<td></td>
<td>DSP Richmond North Substation Project</td>
<td>2200</td>
<td>1674</td>
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<tr>
<td>DSP Georgetown 12kV 2 Substation</td>
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<td></td>
<td></td>
<td>DSP Richmond North Substation Project Distribution</td>
<td>942</td>
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<tr>
<td>DSP Hume Road Sub phase 2 distribution</td>
<td>1576</td>
<td></td>
<td></td>
<td>DSP Russell Corner Circuit Work (2017-2018)</td>
<td>701</td>
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<tr>
<td>DSP Hume Road Substation Phase 2</td>
<td>2001</td>
<td>2301</td>
<td></td>
<td>DSP Russell Corner Substation Project (2017-2018)</td>
<td>3831</td>
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<tr>
<td>DSP BM 1 Okt 0057 Distribution</td>
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<td>DSP Shelbyville North Breaker</td>
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<td>DSP BM 1 Okt 0057 Substation Disconnects</td>
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<td>DSP Shelbyville North Distribution</td>
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<tr>
<td>DSP Innovation Dr 2 Distribution Exit</td>
<td>341</td>
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<td>DSP Simpsonville 1 Substation</td>
<td>191</td>
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<tr>
<td>DSP Kenton to Wedonia Tie Circuit</td>
<td>273</td>
<td></td>
<td></td>
<td>DSP Simpsonville 1 Substation</td>
<td>751</td>
<td>750</td>
<td></td>
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<tr>
<td>DSP Lawrenceburg Substation Property Project</td>
<td>401</td>
<td></td>
<td></td>
<td>DSP Glass Substation</td>
<td>81</td>
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<tr>
<td>DSP Lawrenceburg-Anderson County Substation Project</td>
<td>2000</td>
<td></td>
<td></td>
<td>DSP Viley 2 Distribution</td>
<td>600</td>
<td>600</td>
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<tr>
<td>DSP Middlesboro 1 4kV 124-5 Distribution Conversion</td>
<td>100</td>
<td></td>
<td></td>
<td>DSP Viley 2 Substation</td>
<td>2210</td>
<td>1999</td>
<td></td>
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<tr>
<td>DSP Middlesboro 1 4kV 124-5 Substation Conversion</td>
<td>700</td>
<td>300</td>
<td></td>
<td>DSP Wedonia circuit 965 reconductor</td>
<td>450</td>
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<tr>
<td>DSP Mooman 2.4kV to 7.2kV Conversion Project</td>
<td>118</td>
<td></td>
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<td>DSP West Hickman transformer addition distribution</td>
<td>108</td>
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<td></td>
</tr>
<tr>
<td>DSP M. Sterling Substation Distribution</td>
<td>200</td>
<td></td>
<td></td>
<td>DSP West Hickman transformer addition year 2</td>
<td>1375</td>
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<tr>
<td>DSP M. Sterling Substation Project</td>
<td>1226</td>
<td></td>
<td></td>
<td>DSP Wilson Downing 2 Substation Upgrade</td>
<td>1430</td>
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<tr>
<td>DSP N. Vernon Substation Project</td>
<td>1099</td>
<td>1101</td>
<td></td>
<td>SCMLGE MODIFY CANE RUN PLANT 14KV SUBSTATION</td>
<td>399</td>
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<tr>
<td>DSP N. Vernon Substation Project Distribution</td>
<td>400</td>
<td></td>
<td></td>
<td>SCMLGE PLGE SMAC PROJECT</td>
<td>771</td>
<td>1196</td>
<td>1410</td>
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<tr>
<td>DSP Oxford 1 Okt 0471 Distribution</td>
<td>596</td>
<td></td>
<td></td>
<td>total Major Substation/Circuit</td>
<td>19572</td>
<td>19468</td>
<td>24019</td>
</tr>
</tbody>
</table>

• N-1 Distribution Transformers (N1DT):

The N1DT program was introduced in the 2014 BP to address substations that cannot be restored in the event of a transformer outage or failure during any portion of the year. During these outages some customers could experience outages greater than 24 hours until the equipment is replaced or a portable transformer is installed. Funding included $2.5M in the 2014 BP for work beginning in 2015 escalated across the plan and was expected to address an average of two projects over two years. Funding levels, scope and program length evolved over the 2015 and 2016 BP and this initiative is now a 15 year, $175M program.

This initiative targets large, high impact substations in a priority rank order and includes substation/circuit upgrades, capacity additions and enhancements at critical substations for the purpose of adding contingency for substation transformer failures and outages. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from area stations. This initiative is separate from capacity additions to serve existing customers although it also often addresses near term loading issues in addition to contingency. It also provides additional capacity necessary to support the long term goals of the Distribution Automation initiative. Projects are prioritized in a prioritization model using a benefit
to cost methodology similar to AIS. Projects are evaluated on factors such as the number of transformers a project will remove from the N1DT list, load at risk, percent of year the load is at risk, customers served (by type), age of the power transformer, availability of property and other factors. The first two major projects, both at KU, will be completed in 2016 (Lakeshore and Innovation Drive).

Two recent revisions to the originally envisioned strategy for the program have been made. First, all new major capacity enhancements are now evaluated to also include a contingency provision for substation transformer failures. Where the incremental cost to gain contingency has high benefit/cost value and scores highly in the N1DT prioritization model, the incremental cost component for contingency can be funded with a reallocation of N1DT funding. This process has funded the contingency portion of three projects, Central City, West Hickman and Corbin US Steel.

The second revision to the program was the implementation of a project in 2016 to address reducing outage duration at more rural KU stations not currently targeted under this program. The N1DT Spares and Portables project, completes in 2017 and provides for two new, midsize portable transformers to be purchased and staged in Earlington and Pineville to better address transformer failures (Two KU’s portables are currently shared and stationed in Lexington). The project also includes the purchase of additional spare transformers, and transformer components to speed restoration response in more rural KU areas. The project required additional funding in 2017 (above the $636k included in the original submission of the proposed 2017 BP) in the amount of $545k creating a variance to plan.

Planned spending on N1DT included in the proposed 2017 BP targets the projects listed below. However, projects actually addressed will likely change based on the potential to fund the incremental redundancy portion of capacity projects to achieve N1DT objectives at high benefit to cost ratio.

<table>
<thead>
<tr>
<th>Start Year</th>
<th>First Year Project Name</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>N1DT Portables &amp; Spares</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1181</td>
</tr>
<tr>
<td>2017</td>
<td>N1DT STR Highland Substation Property</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>700</td>
</tr>
<tr>
<td>2017</td>
<td>N1DT STR Plainview Circuit Work</td>
<td></td>
<td></td>
<td>1110</td>
<td></td>
<td>2190</td>
</tr>
<tr>
<td>2017</td>
<td>N1DT STR Plainview Substation Project</td>
<td></td>
<td></td>
<td>1600</td>
<td></td>
<td>3165</td>
</tr>
<tr>
<td>2017</td>
<td>N1DT STR Stonewall 2 Distribution</td>
<td></td>
<td></td>
<td>314</td>
<td></td>
<td>486</td>
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<tr>
<td>2017</td>
<td>N1DT STR Stonewall 2 Substation</td>
<td></td>
<td></td>
<td>1565</td>
<td></td>
<td>1665</td>
</tr>
<tr>
<td>2017</td>
<td>N1DT STR West Hickman transformer addition year 2 - N1DT portion</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>775</td>
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<tr>
<td>2019</td>
<td>N1DT STR Dixie Circuit Work</td>
<td></td>
<td></td>
<td></td>
<td>1200</td>
<td>300</td>
</tr>
<tr>
<td>2019</td>
<td>N1DT STR Dixie Substation Project</td>
<td></td>
<td></td>
<td></td>
<td>3000</td>
<td>1000</td>
</tr>
<tr>
<td>2019</td>
<td>N1DT STR Ashby Circuit Work</td>
<td></td>
<td></td>
<td></td>
<td>1200</td>
<td>800</td>
</tr>
<tr>
<td>2019</td>
<td>N1DT STR Ashby Substation Project</td>
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<td></td>
<td></td>
<td>3000</td>
<td>1000</td>
</tr>
<tr>
<td>2019</td>
<td>N1DT STR Crestwood Area Property</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>800</td>
</tr>
<tr>
<td>2019</td>
<td>N1DT STR Mud Lane/Smyrna Area Property</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>800</td>
</tr>
<tr>
<td>2020</td>
<td>N1DT STR Mud Lane/Smyrna Area Circuit Work</td>
<td></td>
<td></td>
<td>600</td>
<td></td>
<td>1400</td>
</tr>
<tr>
<td>2020</td>
<td>N1DT STR Mud Lane/Smyrna Area Substation Project</td>
<td></td>
<td></td>
<td>2600</td>
<td></td>
<td>2952</td>
</tr>
<tr>
<td>2020</td>
<td>N1DT STR Crestwood Circuit Work</td>
<td></td>
<td></td>
<td>500</td>
<td></td>
<td>1000</td>
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<td>2020</td>
<td>N1DT STR Crestwood Substation Project</td>
<td></td>
<td></td>
<td>2000</td>
<td></td>
<td>2000</td>
</tr>
<tr>
<td>2020</td>
<td>N1DT STR Mud Hikes Lane Area Property</td>
<td></td>
<td></td>
<td>1200</td>
<td></td>
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<tr>
<td>2021</td>
<td>N1DT STR Breckenridge Circuit Work</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>300</td>
</tr>
<tr>
<td>2021</td>
<td>N1DT STR Breckenridge Substation Project</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1500</td>
</tr>
<tr>
<td>2021</td>
<td>N1DT STR Ethel Circuit Work</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>300</td>
</tr>
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<td>2021</td>
<td>N1DT STR Ethel Substation Project</td>
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<td>1200</td>
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<tr>
<td>2021</td>
<td>N1DT STR Kenwood Circuit Work</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>488</td>
</tr>
<tr>
<td>2021</td>
<td>N1DT STR Kenwood Substation Project</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1500</td>
</tr>
<tr>
<td>2021</td>
<td>N1DT STR P&amp;G Ckt 0066 Breaker</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>360</td>
</tr>
</tbody>
</table>

Total N1DT By Year  7245  7506  10000  10000  13000
• **KU SCADA Expansion**

Plans for a significant expansion of SCADA in KU substations first proposed in the 2014 BP at $5M/year has been deferred to allow for effective integration with the Distribution Automation initiative. In both the 2015 and 2016 BP’s, $500k was retained in the first year to allow for the installation of cell enabled meters in non-SCADA KU substations to allow remote monitoring of substation transformer loads. This capability will allow better management of the distribution system under contingency and extreme weather events. Funding in both 2015 and 2016 was released when the promised cell enabled technology compatible with the current LG&E/KU AMI mesh type network and meter head end system did not come to market and funding is again requested in the 2017 BP because of its high value relative to cost. Currently, only 15% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped.

• **Distribution Capacitors**

This program was added to the 2014 BP to provide for the new installation of distribution capacitors targeted to help improve the transmission system power factor. This work was funded in the past by Transmission but the budget was transferred to EDO in 2015 where it will be carried forward. Target areas for power factor improvement are prioritized by Transmission Planning and projects are scheduled to be online near midyear in time for summer peak when the need for power factor support is greatest. This program is also tied with annual inspections and repair and maintenance work on existing capacitors.

**Enhancements for Reliability Improvements**

This category addresses day to day reliability needs and select, high value Major Reliability initiatives and individual projects to address ongoing system reliability issues. It also includes funding for Distribution Automation (DA) and the implementation of a Distribution Management System (DMS) needed to make a step change improvement in reliability to address growing customer expectations for reliable service. Significant funding changes have been made to the Reliability portfolio in the proposed 2017 BP, including a rebalancing of programs that address ongoing reliability issues and an acceleration of the DA/DMS implementation plan from a 10 year implementation in the 2016 BP to 7 year implementation in the proposed 2017 BP. These changes, along with late additions to the plan have resulted in variances in Enhancements for Reliability when compared to the 2016 BP.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Proposed 2017 BP</td>
<td>23,864</td>
<td>38,484</td>
<td>35,687</td>
<td>34,666</td>
<td>35,019</td>
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<tr>
<td>2016 BP Targets (includes 2016BP Rear Easement Hardening *)</td>
<td>18,841</td>
<td>26,518</td>
<td>26,652</td>
<td>27,639</td>
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<td>Total Variance</td>
<td>5,024</td>
<td>11,966</td>
<td>9,035</td>
<td>7,027</td>
<td>6,689</td>
</tr>
</tbody>
</table>

*2016BP amounts 2017-2021 $17,769, $25,441, $25,548, $26,507, $27,169 before including $526k each for LG&E and KU from Rear Easement Hardening

**Reactive Reliability Programs**

In addition to blanket funding needed to address customer driven day to day reliability needs, the 2017 BP plans continues two major programs of strategic value, CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) at both LG&E and KU. A new category, System Hardening has also been added to address high value reliability improvements on circuits not ranking high under CEMI or CIFI. This category includes funding previously falling under a category called Major Reliability Projects in the 2016 BP. A previous initiative in the 2016 BP targeting poor performing small conductor tap lines, named Rear Easement Hardening (+/- $1M/year) has been moved from the Aging Infrastructure category and the funding incorporated under System Hardening because the program’s objectives were primarily reliability, and not age focused. Funding between CEMI, CIFI and now System Hardening has been rebalanced to maximize the benefits of the reliability portfolio due to declining benefits and increasing costs under the traditional CIFI program. This collection of Reliability initiatives in total was consistent with the 2016 BP targets before late additions to the plan although the mix within the individual programs has been changed.
Reliability Improvement Blankets

The Reliability improvement blanket includes funding across the plan that is used to address upcoming reliability issues at the operations centers and unplanned small scale projects to target reliability improvement and/or safety and resiliency of the system. Blankets cover general distribution reliability improvements at the center level driven by customer complaints and abrupt downturns in reliability performance. The proposed 2017 BP plan is approximately $200k above the 2016 BP across the plan. Funding is escalated 3% across the plan.

- **CEMI>5**
  CEMI (Customers Experiencing Multiple Interruptions) is a reoccurring initiative to address circuits whose customers exceeded more than 7 outages in 2015 (CEMI is a one year look). The 2017 BP slightly increases spending under CEMI from the 2016 BP which included $600k for KU and $350k for LG&E. Similar to the CIFI program, total amounts vary by plan cycle based on the number of circuits impacted and by actual circuit performance across both utilities. Funding is escalated 2.5% across the plan.

  Two new sub-initiatives have been incorporated under CEMI in the 2017 BP. Funding has been included under the 2017 CEMI program to address Recurring Outage Devices (RODs) and to address unfused tap lines. RODs contribute significantly to CEMI customers and are protective devices that have operated frequently interrupting service to customers. Addressing these devices will have a favorable benefit on effectively reducing CEMI customers on the LG&E/KU system. In addition, following a GIS query it was determined that 783 LG&E and 7,147 KU single or multi-phase taps do not have dedicated protective devices installed to sectionalize them in the event of a fault. Funding under CEMI will target the installation of 50 tap line fuses in LGE and 100 in KU. An effort will be made in 2017 to define the scope of a project to address all unfused taps in LGE/KU. Installation of tap line fuse provides excellent return on investment by reducing the risk of a larger outage with minimal cost. It also improves the safety of tap lines.

- **CIFI (worst performing) Circuits**
  This initiative covers reactive reliability improvement work on circuits that are prioritized based on each circuit’s 5 year average SAIFI performance. CIFI circuit improvements include updating line protective coordination and targeted aging asset replacements where reliability is negatively impacted. Variances to the 2016 BP are a decrease for KU of $1,480k and a decrease for LG&E of $349k. This initiative has proven performance and value as seen by circuit SAIDI/SAIFI where reliability is negatively impacted. Total amounts vary in each plan cycle by the number of circuits targeted and by actual circuit performance across both utilities.

  In addition, the proposed 2017 BP includes specific projects to be funded from the CIFI program budget. These projects include Dixie 1224 circuit addition, UPS Worldport Underground Cable Replacement and Sectionalization project for LGE and the Liberty tie circuit in Casey County, KY for KU. CIFI projects provide a clear value to the customer and company and were recommended by the 2017 AIS project evaluation team after ranking highly against other projects. Late additions to the plan included an incremental $800k to support an expanded scope for the UPS Worldport Underground Cable Replacement and Sectionalization project (above the $700k already incorporated under the proposed 2017 plan) and $1M/year across the plan to support increased Tap Line Coordination work (listed as a separate item).
• **System Hardening**
  The system hardening initiative focuses on rear easement hardening, conductor upgrades, and circuit relocations. Generally, rear easement hardening covers the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of this program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, elimination of secondary, replacement of aged and defective equipment, and/or relocations of lines to less problematic areas. System hardening projects are prioritized based on AIS rankings. Project funding comes from the previous Major Reliability Projects (funding varied by year), Rear Easement Hardening (2016 BP +/- $1M) and funding targeted as CIFI improvements in previous plans.

• **Distribution Automation**
  Funding for this initiative has been accelerated from a 10 year implementation plan to a 7 year implementation plan resulting in the following variances to the 2016 BP.

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Distribution Automation</strong></td>
<td></td>
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<td>20,650</td>
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<td>13,750</td>
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<tr>
<td><strong>Total Variance</strong></td>
<td>(3,446)</td>
<td>(11,180)</td>
<td>(8,250)</td>
<td>(7,250)</td>
<td>(6,900)</td>
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DA (Distribution Automation) is the extension of intelligent control of the electrical power grid functions to the electric distribution level. Intelligent control of distribution equipment will provide near real-time information from the distribution system and allow for the remote control and automation of distribution line equipment. The proposed DA program will install electronic Distribution SCADA (Supervisory Control and Data Acquisition) connected reclosers to improve reliability by remote monitoring and control, segmentation of feeders, and “self-healing” of the distribution system. For customers, this means fewer outages and faster restoration times.

Previously a 10 year implementation plan in the 2016 BP, the proposed DA program is now a 7-year initiative beginning in 2016. The scope includes the implementation of a DSCADA (Distribution SCADA) system integrated with a DMS (Distribution Management System) and the installation of approximately 1,450 DSCADA connected electronic reclosers. This change in the implementation plan is requested to achieve the next step change in Reliability (SAIDI SAIFI improvement) for Electric Distribution. This new initiative begins with the installation of SCADA controlled electronic reclosers which provide an immediate reliability benefit on select circuits beginning in 2017. The installation and turn-up of Distribution SCADA (DSCADA) and a Distribution Management System (DMS) allowing LG&E/KU to begin implementing FLISR (automatic Fault Location, Isolation, and Service Restoration) of field devices. Funding for this program varies across the years depending on the number of reclosers installed and circuits completed and available resources (both internal and external). Headcount to support this initiative is included in the WFP beginning in 2017. A communication study will be completed in 2016 prior to any new recloser installations (recloser install begins in 2017).

**Public Works, Mandated Relocations and Customer Requested Projects**
These categories cover alterations or relocation of distribution facilities to accommodate public works projects and provides funding for customer requested facility relocations prior to reimbursement by customers. This item is funded based on historical spend levels and includes a 3% escalation across the plan.

3. **Maintain the Network Category**

The Maintain the Network category includes capital blanket and project specific funding to maintain the condition of the system, replace failed or defective distribution and substation equipment, and specific projects to address aging infrastructure. Work specific to maintain, repair and replace distribution equipment is broken into the four main categories listed in the table.
below and covers distribution lines, substations, street lighting, distribution relocation work driven by transmission projects, and substation buildings and grounds. One new sub-category was added to the 2017 BP to address non-reimbursable pole replacement work that is expected to be driven by large fiber deployments under initiatives like Google, KYWired, and Fibertech. Transmission reliability and compliance work is also driving enhanced funding needs for unidentified projects and new/additional funding for defined distribution projects that did not appear in the 2016 BP.

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<tbody>
<tr>
<td>Repair/Replace Defective Equipment (Incl. Substation Maint.)</td>
<td>34,224</td>
<td>34,392</td>
<td>38,793</td>
<td>37,096</td>
<td>37,529</td>
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<tr>
<td>Fiber Non-Reimbursable R/R Defective Equip</td>
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<td>2,093</td>
<td>2,000</td>
<td>2,000</td>
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<td>15,003</td>
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<td>64,328</td>
<td>69,356</td>
<td>66,362</td>
<td>67,558</td>
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**Maintain the Network - Repair/Replace Defective Equipment (Incl. Substation Maint)**

Repair/Replace Defective equipment consists of blankets and specific projects in seven categories covering defective or failed equipment in substations and on lines. Substation categories cover work to replaced failed equipment, address wildlife, lightning and code compliance issues, repair building and grounds and oil containment improvements/repairs. The Distribution Lines category of repair/replace includes blanket funds for reactive replacement of failed or defective overhead and underground equipment, cable, vaults and manholes, padmounted switchgear, distribution facility relocation work driven by increase in Transmission upgrades and compliance initiatives, and any major, identifiable repair/replace projects.

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<tr>
<td>Repair/Replace Defective Equipment - Substation Maintenance</td>
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<td>3,122</td>
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<td>Repair/Replace Defective Equipment - Transmission Line Clearance</td>
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<tr>
<td>Repair/Replace Defective Equipment - Blankets</td>
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<td>30,311</td>
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<td>LEO Padmount Switchgear R/R</td>
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<td>199</td>
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<td>Repair/Replace Defective Equipment - Major Projects</td>
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<td>398</td>
<td>320</td>
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<tr>
<td>Distribution Crossing Relocations for NRP</td>
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<td>TOTAL Repair/Replace Defective Equipment</td>
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<td>34,393</td>
<td>38,793</td>
<td>37,096</td>
<td>37,529</td>
</tr>
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</table>

- **Repair and Replace Defective Equipment Blankets – Substation Maintenance**
  
  This grouping of projects covers the cost of reactive repair and replacement of defective substation equipment at each substation operations center. Specifically, these projects include the replacement of failed equipment that cannot be effectively repaired, wildlife protection at unproctected stations, upgrades for compliance (NESC, cooling fans, oil containment capital repairs), building and grounds repairs, and minor improvements to reduce future maintenance/repair (transformer oil filtration, addition of lightning protection). 2019 spending is escalated above the 2016 BP plan by three separate, specific substation repair projects (Pocket, Tom’s Creek and St. Charles). Other years are essentially to the 2016 BP.

- **Purchase KU Portable Transformer**
  
  Funding for this project was in the 2016 BP for 2017 ($2.2M) and 2018 ($200k). The 2017/2018 project was to purchase a large portable transformer for the Lexington Operations area to support outage restoration and planned maintenance work on larger transformers. The purchase of an additional portable transformer (KU currently only has one large portable) for KU was seen as needed to minimize outage duration caused by larger substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. Midyear 2016, funding for this project was reallocated to support the N1DT Spares and Portable Transformer project for contingency for the more rural KU areas. A need was still seen during the business planning cycle for a large new portable for the Lexington area and this project was resubmitted in AIS with purchase planned in 2019 and 2020.
• **Transmission Line Clearance**
  This blanket level funding is used to cover the cost of undefined distribution line relocations and upgrades during the year driven by Transmission pole replacements, relocations and compliance directed (NERC) clearance projects. Funding in the 2016 BP was approximately $300k split between KU and LG&E. A late addition to the plan added $450k to this category increasing funding to approximately $750k/year. The increase is necessary to address distribution work driven by increased transmission pole replacements and clearance work. This category is escalated approx. 1%/year across the plan.

• **Repair and Replace Defective Distribution Equipment Blankets - Lines**
  This blanket item covers the cost of repairing and replacing defective overhead and underground distribution line material and equipment at each operations center. Maintenance repairs and replacement of capacitors, poles, cable, vaults, and street lighting are included in this category. Funding is based on historical spend levels and is escalated at 3%/year across the plan.

• **Louisville Electric Operations Padmount Switchgear**
  This program replaces aged and defective, high risk padmounted switchgear in underground commercial and large residential areas that has been identified during system inspections. The program is necessary to address increasing failure rates on highly deteriorated equipment and to replace equipment that cannot be effectively maintained. This program covers approximately 10 padmount switchgear replacements per year.

• **Repair and Replace Defective Equipment Major Projects**
  This category covers major projects targeting defective distribution equipment not covered under other categories, including large planned transmission driven distribution upgrades and relocations. 2019 funding consists of two distribution projects in different KU Operations centers to remove portions of the same out of service line (Roundhill) that has become an operational concern ($238k). Two large planned transmission upgrades are also included. The 2017 Lexington Plant-Pisgah project was a late addition to the plan ($550k) and a planned relocation for transmission line in the Shelbyville Operations center in 2019 and 2020 ($160/$320k-2019/2020).

• **Distribution Crossing Relocations for NERC Rating Program (NRP)**
  This project was a late addition to the plan that involves distribution relocations or undergounding for LG&E and KU to address transmission clearance conflicts at distribution crossings. The distribution work, where more cost effective than transmission improvements, could involve line relocation or placing the lines underground in the span where the conflict exists. This one time initiative is funded at $200k for 2017 to clear up previously identified conflicts.

**Maintain the Network - Fiber Non-Reimbursable R/R Defective Equipment**
This category is new to the 2017 BP and covers non-reimbursable distribution work associated with anticipated large fiber network buildsouts by Google, KYWired, and Fibertech. Large fiber deployments include reimbursable and non-reimbursable distribution work. Reimbursable work is not budgeted as costs are recovered - work includes pole replacements for clearance or strength and other make ready work to allow new attachments. Non-reimbursable work includes corrections identified while assessing the system as part of the approval process for new attachments where the corrections are the responsibility of the utility. This includes the replacement of defective poles and pre-attachment overloaded poles as well as preexisting clearance violations. $2M is included across the plan for a potential Google deployment. $198k is included in the first two years of the plan for the KYwired deployment at KU ($170k/20k - 2017/2018) and $600k for LG&E/KU ($527/$73 - 2017/2018). $275k is included in the plan in 2017 for the Fibertech deployment at LG&E.

**Maintain the Network - Aging Infrastructure Distribution and Substation**
EDO’s Aging Infrastructure programs fall into three broad areas, LG&E’s Downtown Network System, Substations Equipment and Distribution Cable Systems. Aging infrastructure initiatives are driven by available data by age, quantity in service, failure data, field experience, equipment specially knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The age of the distribution system and increasing failure rates has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets that are beyond their expected life expectancy in areas where they have resulted in declining
reliability or unacceptable risk. Central downtown Louisville infrastructure in the Network area was originally built in the early 1900’s and many of the manholes, duct, vaults and cable are approaching or exceeding 100 years old. In General, robust system expansion in the 1960’s and 1970’s has created substantially high groups of equipment and material, in particular underground cables with similar age and created the potential for very high failure rates in future years if not addressed incrementally. Critical substation equipment continues to age beyond expected life and is becoming less reliable while increasing the operational expenses necessary to maintain the equipment.

Funding is included in the plan to continue major strategic infrastructure enhancement programs addressing PILC Replacement, Legacy Substation Equipment, aging cable systems and other poor performing or high risk distribution facilities. For the 2017 BP, two new, and three expanded programs are funded. Four of the five changes address deterioration of the downtown network system infrastructure. Increased need and late additions to the plan drive variances in each year in several categories.

- **LEO Downtown Network Vault Structural Repairs**: +/- $900k in additional funding for existing program to address backlog of critical network vault structural repairs.
- **LEO Manhole Structural Repairs**: New +/- $213k item to address growing backlog of manhole structural issues found under the PILC program.
- **PILC Cable Replacement**: $500k incremental added to existing program to address increased need to replace duct as part of the PILC program.
- **PILC Cable Replacement - Curb to Curb Paving**: New $700k item to plan to address potentially high repaving costs driven by increased duct work under the PILC program due to changes to the Metro Louisville Asset Management program which now requires curb-curb paving.
- **URD Cable Rejuvenation Program (KU & LG&E)**: $1.2M Incremental to accelerate the pace of URD cable rejuvenation to further reduce the rate of failure and potentially initiate a reduction in operating costs to address ongoing failures.

A description of major programs are listed below and are grouped by Network Systems, Substation Renewal and Cable Systems.

**Network System Aging Infrastructure Programs**

There are five separate network Aging Infrastructure initiatives in the plan for LG&E, including expanded funding for vault structural repairs and PILC and a new initiative targeting structural deficient manholes. One late addition to the plan was incremental funding to address new Metro Louisville Asset Management requirements that are likely to drive a significant increase in the cost to install duct in the Network by requiring curb-curb repaving for street cuts. Many of the cable systems, manholes and vaults in the network date to the early 1900’s and are being found in increasingly poor condition.

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<td><strong>Aging Infrastructure – Network</strong></td>
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<tr>
<td>PILC Cable Replacement</td>
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<td>PILC Cable Replacement - Curb to Curb Paving (new)</td>
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<td>700</td>
<td>700</td>
<td>700</td>
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<td>LEO Downtown Network Vault Structural Repairs (expanded)</td>
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<td>218</td>
<td>224</td>
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<td>235</td>
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<tr>
<td>Downtown Network Vent Type Protector Replacement</td>
<td>500</td>
<td>513</td>
<td>525</td>
<td>538</td>
<td>552</td>
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<td><strong>TOTAL Aging Infrastructure Network</strong></td>
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<td>9,717</td>
<td>9,963</td>
<td>9,716</td>
<td>9,977</td>
</tr>
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</table>

- **Paper Insulated Lead Covered (PILC) Cable Replacement**
  This program continues work started in 2013 and involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability and safety concerns. This $62M, 11 year program is scheduled to complete in 2023. Under this program approximately 7 miles of PILC cable is planned for replacement each year until program completion. Targeted cable is between 50 and 90+ years old and the program includes the cost for new duct
systems where existing duct systems are not adequate or usable which is increasingly being found to be the case. Program scope and funding has evolved, as follows:

- **2013**: Initiated program at $2M for 20 years to fund cable replacement (escalated by 2.5% per year).
- **2014**: BP included funding of $4M ($2M incremental escalated at 2.5% per year) to accelerate the program before adding an additional $2M ($6M total) to further accelerate the program and address higher than expected duct and manhole repairs and replacements. Shortening the program from 20 to 10 additional years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced.
- **2015 – Current**: Continue funding at $6+M escalated level for 9 additional years with projected completion in 2023 (escalated by 3% per year). Significant levels of manhole and duct line structure deterioration encountered during the program has the potential to accelerate the program beyond the current 10 year replacement program. The program continues to validate and quantify remaining targeted assets.
- An additional $500k was added to the plan above 2016 BP targets to address increasing duct replacement costs.

**PILC Cable Replacement - Curb to Curb Paving**

This new item addresses changes implemented in 2016 under Metro Louisville’s Asset Management requirements governing utility work in public rights of way in the downtown area. New requirements for work in public roadways will no longer allow for partial repaving for larger street cuts typically associated with duct line replacement work under the PILC replacement program. The majority of network cables reside in the street and new requirements require curb-curb paving as part of the street restoration process for open cuts. It is unknown at this time how rigorously the new requirements will be enforced. Increasingly, PILC cable replacement is requiring the installation of new duct because of the lack of spare, open duct or because the existing duct system has collapsed or deformed and will not allow existing cables to be removed or new cables to be installed. Under these conditions, streets must be cut and excavated and new duct installed. $700k in incremental funding was added to the 2017 BP to address expected incremental costs to the PILC program to stay on its current completion schedule in 2023.

**Louisville Electric Downtown Network Vault Structural Repairs**

This proactive program targets necessary repair and replacement of deteriorated vault structures including vault tops and ventilated openings (in sidewalks), steel ceiling header beams, and deteriorated brick and concrete walls in downtown Louisville Network vaults that have deteriorated as a result of age and deicing salts. The program originally targeted only vault top replacements; however, increasingly significant deficiencies are also being found in vault structural walls and supports requiring an increased cost for repair. Deteriorated vault structures, if not repaired, increase the risks to public safety, damage to high cost network transformers and equipment located in the vaults, and network service reliability. Funding has been increased in the 2017BP ($1.2M) over the 2016BP level ($283k) due to rapidly growing backlog of defective vaults. Deteriorated structural conditions are noted on periodic inspections and are reviewed by a structural engineering consulting firm to determine the type and priority of repair and replacement needed. Requested funding will typically allow the repair of 2-3 vault top replacements and 2-3 vault support structural repairs depending on the size of the vaults and the nature of the defects. There are currently 190 vaults in the downtown Louisville network.

**Louisville Electric Downtown Network Manhole Structural**

This new, proactive program targets necessary repair and replacement of a growing backlog of deteriorated manhole structures including cracked ceilings, sagging and caved-in brick and concrete walls, sinking floors, and corroded structural hardware as a result of years of settling soils from sewer and water main breaks, vibration from surface traffic, and deicing salts. Deteriorated manhole structures, if not repaired, increase the risk to public safety and network service reliability. This is a new project in the 2017 BP ($213k) in response to a growing list of deteriorated manholes found during PILC program work and through periodic inspections. Deteriorated manholes are reviewed by a structural engineering consulting firm to determine the type and priority of repair and replacement needed. Requested funding will typically allow the repair of 14 manholes at approximately $15k/manhole depending on varying conditions. There are currently more than 900 manholes in the downtown Louisville network area with many dating to the early 1900’s.

**DT Network Vent Type Protector Replacement**

This program has been in the plan for several years and is funded to begin at $500k in 2017 with a growth of 2.5% across the plan. This program initiates the replacement of aged network protectors that are not submersible rated for below ground application in vaults subject to corrosion damage from sidewalk deicing agents and occasional flooding from
heavy rains and water main breaks. The program will address the most critical of these assets and further enhance the integrity of the downtown network in conjunction with other current or past network aging infrastructure programs (PILC, manhole lids, SCADA/AMI, vault/manhole repairs, etc.). Funding is consistent with the 2016 BP.

**Substation Aging Infrastructure Programs**

This collection of programs covers the annual replacement of aged, critical, maintenance intensive, unreliable substation equipment and/or equipment nearing obsolescence. These programs include equipment such as substation batteries, protective relays, 15kV and 34kV power circuit breakers, Remote Terminal Units, cap and pin insulators, Load Tap Changers (LTC), and regulator controls. In 2012, Substation Construction and Maintenance identified a “Top 5 List” for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in service, field experience, and equipment specialty knowledge. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure programs have been in past business plans but funding levels have varied in the individual initiatives due to capital funding constraints and as program initiatives are completed and new ones are identified. Funding needs vary somewhat each year as program initiatives are completed and new ones are identified. The group as a whole is relatively level to the 2016 BP except for Power Circuit Breakers where the 34kV breaker program completes in 2019 creating a positive variance.

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<td>Substation - Remote Terminal Units</td>
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<td>Substation - Cap and Pin Insulator Upgrade</td>
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<td>Substation - ABB VHK MECH</td>
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<td>2,319</td>
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**Underground Cable System Aging Infrastructure Programs**

The 2017 BP contains two primary initiatives to address aging, non-network underground cable systems. One initiative targets very old and/or poor performing substation exit cables on the LG&E system where most circuits exit the substation underground. The second initiative is a program to rejuvenate in place, early generation Underground Residential Cables (URD) at both LG&E and KU. A late addition to the plan added additional funding for URD Rejuvenation in the amount of $1.2M/year ($1M-LG&E, $200k-KU) in each year of the 2017 BP based on a demonstrated improvement in failure rates since program inception and because the additional funding could lead to a reduction in operational expenses associated with repairing ongoing cable failures.

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<tr>
<td>Underground Cable Replacement Substation Exits - LGE</td>
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<td>2,641</td>
<td>2,707</td>
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- **Substation Underground Cable Exits (LG&E)**

This program began with funding of $1M in 2015 with a growth of 2.5% across the plan, and funds the replacement of PILC and the poorest performing solid dielectric substation exit cables. Substation exit cables have significant reliability.
implications because an entire circuit is lost until the location of the failure is identified. Targeted substation exits are between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts. This funding will provide funding for the replacement of 8-10 substation exits depending on the number and length of cable sections replaced. Funding is consistent with the 2016 BP.

- **Underground Cable Rejuvenation/Replacement (LG&E/KU)**
  This program first piloted in 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are typically 40-45 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables by more than 20 years by injecting dielectric fluid into the cable to restore the insulation strength to near new condition. The rejuvenation/replacement program is funded to levelize and/or slightly reduce cable failures and more expensive cable replacements. Sufficient performance data is now available and shows a correlation between the start of the cable rejuvenation/replacement program and a slight decrease in failure rates of vintage cables, however the cable systems as a whole continue to age. Past year’s funding constraints did not allow the desired expansion of this program. Late in the planning cycle an incremental $1M for LG&E and $200k for KU was added to the plan to expand the program. An expansion of the program will result in contract rejuvenation crews being on site all, or the majority of the year. Having onsite contractors will enable the ability to repair and rejuvenate cable failures allowing failure repair to be capitalized. Without rejuvenation, cable repairs are expensed.

**Maintain the Network - Pole Inspection and Treatment Program**
This item continues the Pole Inspection and Treatment initiative which started in 2010 at $8.5M. This program is funded at $11.6M in 2017 with a growth of 3% across the plan. This program covers the capital cost to inspect and extend the life of wood poles though preservative retreatment and reinforcement and covers the cost of defective or overloaded pole replacements identified under this program. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle). Funding for 2017-2021 is consistent with the 2016 BP.

**Rear Easement Hardening**
Formally classified as an Aging Infrastructure initiative, funding for Rear Easement Hardening has been moved to the new System Hardening category under Enhancements for Reliability because the objectives of this program were driven more by Reliability than Aging Infrastructure.
4. **Repair the Network Category**

The Repair the Network category consists of two primary categories that cover the capital cost of damages by third parties, weather and non-weather related system repairs, and substation transformer repairs and rewinds. Storm related work is adjusted annually to 10 year averages. Other blanket items in this category are based on historical trends and volumetrics. As a category, variances to the 2016 BP of approximately $200k in 2017 and beyond are the result of an increase in storm related restoration costs.

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<tr>
<td>Repair the Network</td>
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<tr>
<td>Storm Restoration</td>
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<tr>
<td>Non Weather System Restoration and Third Party Damages</td>
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<td>TOTAL Repair the Network</td>
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**Storm Restoration**

- **Storm Restoration**
  This blanket item funds the capital portion of storm related repairs. Funding is based on a 10 year average cost adjusted by the consumer price index. The 2016 BP contained $3,292k in 2017 and this category is adjusted by the CPI index across the plan. The variance of approximately $200k is due to a change in the 10 year average cost of storm restoration.

**Non Weather System Restoration and Third Party Damages**

This category has three components shown below. 2016 BP funding for 2017 was $9,717 and 2017 BP amounts are consistent with the 2016 BP.

- **Third Party Damages**
  This blanket item covers the capital cost of unreimbursed repairs to utility facility caused by third parties. Funding is based on historical trends and volumetrics.

- **Non-Weather System Restoration**
  This blanket item covers the cost of routine, non-storm related service restoration at all operations centers. Funding is based on historical trends and volumetrics.

- **Substation Transformer Rewinds** – (Combined LG&E/KU $2.5M-2017 escalated 3% across the plan)
  This blanket item covers the cost of substation transformer repairs and the cost to rewind failed transformers for reuse. Funding is based on historical trends and volumetrics.

5. **Miscellaneous Network Category**

The Miscellaneous Network category consists of miscellaneous capital projects not directly associated with connecting new customers or enhancing, maintaining or repairing the network. The Miscellaneous category consists of projects to address special needs when necessary, but generally consists of three main categories, Tools and Equipment, Vehicles, and Equipment for Asset Management. An additional category was added this year to reflect special funding needs to explore options (including the expansion of the Transmission Control Center in Simpsonville, KY) to allow the implementation of a centralized Distribution Control Center. Significant variances to the 2016 BP across the plan include a reduction in vehicle purchases resulting from a change in strategy to leased vehicles instead of purchased vehicles which created a reduction of $5.8M in 2017 and varying levels of reductions across the remainder of the plan. The variance to expand the Simpsonville facility results in a variance of a $5M in both 2017 and 2018.
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<tbody>
<tr>
<td><strong>Miscellaneous (Incl Servco)</strong></td>
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<tr>
<td>Tools &amp; Equipment, Miscellaneous Items</td>
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<td>714</td>
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<td>Equipment Purchases for Asset Management</td>
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<td>Simpsonville Facility Enhancement for DCC</td>
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<td>Purchase of Vehicles/Garage Equipment</td>
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<td>6,044</td>
<td>1,064</td>
<td>1,059</td>
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- **Tools and Equipment**
  This item funds the capital portion of tool and equipment purchases at all operations centers within EDO. Funding is based on historical trends supplemented as necessary to fund large, costly equipment when needed. Funding in consistent with the 2016 BP.

- **Equipment Purchases for Asset Management**
  This item funds the capital purchase of computer hardware and associated equipment such as plotters, survey equipment, and GPS units to support both Gas and Electric Operations. Funding in consistent with the 2016 BP.

- **Simpsonville Facility Enhancement for DCC**
  This new item identifies funding needs for a facility expansion of the Transmission Control Center in Simpsonville, KY. Expansion is necessary to implement a centralized and expanded Distribution Control Center (DCC) for both KU and LG&E. Currently DCC functionality is split between two control centers, one for LG&E at the Broadway Office Complex in Louisville, KY and one for KU at Quality One in Lexington, KY. Centralized and expanded distribution dispatch is required to effectively implement Distribution Automation (DA) and a Distribution Management System (DMS). Funding of $5M is planned for both 2017 and 2018 to coincide with the rollout of the DMS system and is a variance to the 2016 BP.

- **Purchase of Vehicles and Equipment**
  This item funds the purchase of vehicles within EDO. The 2016 BP included significant funding to support the planned purchase of vehicles with funding varying from $5.8M in 2017 to as high as $10M in 2019 to support the purchase of Tier 1 and 2 vehicles. A change in strategy to leased vehicles led to significant reductions in this category.
Electric Distribution Operations Capital Business Plan
High Level Summary
Updated 7/30/2015

Background
The Electric Distribution Operations business plan consists of five strategic categories: **Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous.** Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual routine work and equipment purchases where such work cannot be defined in advance. Work is typically driven by short cycle, high volume work requests. Blanket funding is trended from historical actual expenses, volumetric trends, and local economic indicators and is adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, relocations, operation center driven reliability and enhancement work, and capital repairs or replacement of failed or damaged equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model and ranked using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability, and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program (PITP), Aging Infrastructure (AI) programs, Reliability Initiatives, and Capacity Enhancements are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value. A technical review team of subject matter experts from various functional areas of EDO reviews and validates the project metrics for each project before projects are prioritized by AIS. The final plan is developed following reviews by EDO Directors and the VP, EDO and adjusted as necessary to address funding for key initiatives and strategies.

   The Connect New Customer category largely consists of blanket projects trended across the plan to cover the ongoing cost to extend electric facilities to serve new customers (or load) and the associated costs of equipment such as distribution poles, pole and padmount transformers, and conductor. Known major projects to serve new loads, such as substation improvements or major circuit work for a single customer are identified individually but do not occur in the plan every year. Funding for this category includes $64.38M in 2016, a slight reduction (1.5%) from the 2015 Business Plan (2015BP) ($65.358M). The variance is due to in part to the cancelation of two large new business related substation projects with planned expenditures in 2016 (Corning Danville, Delaplain) resulting from deferment or cancelation of expected customer load growth. This reduction was partially offset by one major new substation and circuit work project
expected to be required to serve new load in 2016 (Toyota South 4 - $3,300k; $2,700k 2016, $600k 2017). Excluding Major Projects, LG&E escalation assumed at 8% (5% growth and 3% material/labor increases) and KU escalation assumed at 3% (0% growth and 3% material/labor increases). Major impacts are lower growth rates in recent years offset by higher than inflationary costs for connecting new customers as they move to urban centers for employment (economic growth is offset by churn) particularly in the LG&E areas. New Business blankets are forecasted using historical actual expenses, volumetric trends, and local economic indicators and are verified against the system sales forecast for consistency. $2M of transformer purchases were later pulled into 2015.

2. **Enhance the Network Category**

The Enhance the Network category includes major and minor system improvements required to serve growing load and to enhance the reliability, safety and/or durability of the system. Blanket funding for mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) is also included in this category. All enhancement work is further subdivided below in the Categories of Enhancements to Meet Demand, Enhancements for Reliability, Mandated Relocations, and Customer Requested Projects.

**Enhancements to Meet Demand** specifically addresses current loading issues or expected overloads, capacity additions for contingency, expansion of SCADA, and other non-reliability system enhancements. Additionally, the 2016BP also requests incremental funding to address a regulatory driven mandate to reduce employee’s arc flash exposure for work in the LG&E downtown secondary network. Further details of the Enhancements to Meet Demand subcategory are shown below:

- **System Enhancement Blankets** – ($1.9M in 2016 and escalated 3% across the plan)

  This item includes blanket funding at each distribution operations center to cover necessary, but currently undefined enhancements required each year. Funding is based on historical spend levels.


  Large, generally multiyear substation/circuit work projects are planned so that they can be completed in the year when the asset is forecasted to reach 95% - 100% of its “normal” operating limit including known or potential new loads. Also included are other enhancement projects that have demonstrated value. The forecasted load of capacity projects is based on a 10-year non-coincidental substation load forecast which is updated annually. Projects can also be placed in the plan when substations and circuits are at risk of exceeding their “emergency” operating limits under extreme weather events (such as the Polar Vortex of 2014 and Artic Blast of 2015) or where projects have substantial reliability benefits. The number of major new projects varies across the plan due to expected load
growth (from the forecast) and/or expected reliability benefits. Projects in the outer years of the plan may be adjusted forward or backward in future business plans based on actual load growth, funding limits and the need to fund other more critical needs that develop in the next several years. All major enhancement projects are summarized below:

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<th>Project and Funding ($000)</th>
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<th>2017</th>
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**N-1 Distribution Transformers (N1DT):** The N1DT program was introduced in the 2014BP to address substations that cannot be restored in the event of a transformer outage or failure during any portion of the year. During these outages some customers could experience outages lasting 24-36 hours until the equipment is replaced or a portable transformer is installed. Funding included $2.5M beginning in 2015 escalated across the plan and was expected to address an average of two projects over two years. Funding in 2019 was later removed from the 2015BP to meet capital targets. While staying to plan in 2016, additional funding above target was originally requested in years 2017-2020 to complete projects of major concern, generally in the Louisville and Lexington area under an accelerated 11 year program. This would have required a funding increase to $10M in 2017 and $20M in years 2018–2020 to accelerate the N1DT program. Funding was then scaled back to complete this work over a 15 year period with funding in 2016 remaining at plan (less pull forward) and funding of 2017-$7M, 2018-2020-$10M.
This initiative includes substation/circuit upgrades, capacity additions and enhancements at critical substations for the purpose of adding contingency for substation transformer failures and outages. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from area stations. This initiative is separate from capacity additions to serve existing customers although it also often addresses near term loading issues in addition to contingency. It also provides additional capacity necessary to support the long term goals of the Distribution Automation initiative. Projects are prioritized in a prioritization model using a benefit to cost methodology similar to AIS. Projects are evaluated on factors such as the number of transformers a project will remove from the N1DT list, load at risk, percent of year the load is at risk, customers served (by type), age of the power transformer, availability of property and other factors.

Projects initiated in 2015 that will complete in 2016 include a transformer addition (Lakeshore 3) and a transformer upgrade (Innovation Drive). One additional project planned for 2016 at Central City and Central City South for $745k was moved up for completion in 2015. The individual projects are identified below of the summary of spending amounts. N1DT projects are dynamic and will be continually revised as other capacity enhancement change project priorities and as better engineering information becomes available.

- 2016 - 6 projects, $1.8M (Does not include 2 projects for $745k pulled into 2015 for Central City)
- 2017 - 6 projects, $7M ($4.4M incremental)
- 2018 - 8 projects, $10M ($7.3M incremental)
- 2019 - 6 projects, $10M ($10M incremental)
- 2020 - 8 projects, $10M

<table>
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<th>N1DT Projects:</th>
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### KU SCADA Expansion, $500k-2016
First included in the 2014BP at a funding rate of $5M, the SCADA expansion was reduced to $500k across the plan in the 2015BP to install equipment for load monitoring and equipment monitoring and control at critical KU substations that currently lack any SCADA capabilities. Due to capital constraints, funding was later removed in years 2016-2019 with funding in 2015 retained to install cell enabled smart meters in non-SCADA stations to enable near real time monitoring of substation transformer loads. Approved funding for 2015 was later released when the vendor’s rollout of their cell based technology was delayed. Funding was originally planned to be restored in years 2017-2020 to the $500k level but was later eliminated leaving only the 2016 funding in the plan. Currently, only 15% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped. Similar to the 2015BP, 2016 funding targets the installation of AMI meters in non-SCADA.

### LG&E Downtown Network Arc Flash – Primary Switches and Secondary Links (New 2016) $2.2M-2016
In 2014, OSHA significantly revised standard 1910.269 which governs work performed by utility employees on distribution systems and for the first time implemented requirements for protecting employees from arc flash (previously covered by an exception in the NESC). The new regulation resulted in the need to install equipment on network transformer and protectors on the 480V network (216V network is unaffected and can be worked in normal PPE) to allow routine work on protectors without taking extraordinary measures. An arc flash in an energized protector is extremely hazardous due to high available fault currents (>200kA in some cases), and its box like configuration and close bus bar spacing. The secondary side of a protector (bus side) cannot be de-energized in most cases unless the connecting leads are disconnected, a time intensive process. Because the primary switch on a transformer is a non-load break switch,
the transformer cannot be de-energized unless the primary circuit is first de-energized. De-energizing the primary places the network in an N-1 condition which is avoided when possible to speed work and to ensure network reliability. Currently, protector work in most cases can’t be performed under the new regulations even in a flash suit unless at least the transformer is de-energized. Heavy flash suits are impractical to work in for long periods of time in hot, dimly lit underground vaults. This initiative is to install primary side medium voltage switches on all 480V transformers and a small number of secondary disconnects on high exposure vaults by the end of 2016 to allow protector work to be performed in standard PPE. This will maintain the flexibility to perform work efficiently and will significantly improve worker safety. The program is expected to take two years to complete with $975k approved for 2015 and $2.2M in 2016 which targets the balance of 219-480V transformer/protectors.

Additional projects are designed to enhance the safety or integrity of the system, including:

- **Downtown Louisville Network Manhole Lid Replacement ($217k in 2016, pulled into 2015)** This program, started in 2013, enhances public safety in downtown Louisville by replacing conventional manhole lids with lids that are designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. The program is focused on manholes located in the downtown Louisville network area. The planned 2016 funding, which has been pulled into 2015 will complete the program.

- **Lexington Area Manhole Lid Replacement ($52k in 2016, pulled into 2015)** This program, started in 2013, enhances public safety in the central Lexington area by replacing conventional manhole lids with lids designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. This funding was to complete the planned deployment and funding was also pulled into 2015.

- **Distribution Capacitors (Combined LG&E/KU $278k 2016-2018, $287k 2019-2020)** This program was added to the 2015 EDO BP to provide for the installation of distribution capacitors targeted for transmission system power factor improvement. This work had been funded in the past by Transmission but the budget was transferred to EDO in 2015.

Enhancements for Reliability Improvements are to address day to day reliability needs and select, high value Major Reliability Projects. The plans includes two major programs of strategic value, one of which is new in the 2016BP. The first program consists of two initiatives to enhance reliability of circuits that are historic poor performers. The second initiative requests incremental funding to implement a step changing proactive improvement in reliability by the staged implementation of Distribution Automation (Smart Grid).
- **Reliability Improvement Blankets** - (combined KU-LG&E $2,102k in 2016, escalated by 3% through 2020).
  The Reliability improvement blanket with funding across the plan is used to address upcoming reliability issues at the operations centers and unplanned small scale projects to target reliability improvement and/or safety and resiliency of the system. Blankets cover general distribution reliability improvements at the center level driven by customer complaints and abrupt downturns in reliability performance. The 2015BP included $2,190k in 2016 also escalated across the plan.

Initiatives targeting reactive work on historically poor performing circuits include CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) and high value smaller reliability project work evaluated using the AIS financial model. Funding levels in the 2016BP were adjusted to reflect the current number of circuits in each category and escalated across the plan.

- **CIFI (worst performing) Circuits** – (2016 $4M-KU, $3.75M-LGE escalated 2.5% across the plan)
  (Previously CIFI Level 1, 2, & 3). This initiative covers reactive reliability improvement work on circuits whose 5 year average SAIFI performance exceeds the average circuit performance by more than one standard deviation. Previously segregated by standard deviation from the mean circuit performance (i.e. CIFI I - 4 standard deviations or more, CIFI II – 3 standard deviations, etc.), the three past initiatives have been combined into one project to allow more effective management. Combining funds of three sub-initiatives will simplify allocating funding across categories. Because circuits are always worked from the worst performers to the better performers no further benefit was seen for allocating by level. Circuits identified for improvement will be limited to those circuits that have not had past Reliability work completed. Variances to the 2015BP are an increase for KU of $1,010k and a decrease for LG&E of $2,490k. This initiative has proven performance and value as seen by circuit SAIDI/SAIFI before/after metrics but future business plans will likely begin to reduce funding in this category to address diminishing returns. Total amounts vary in each plan cycle by the number of circuits targeted (by standard deviation away from mean) and by actual circuit performance across both utilities.

- **CEMI>5 (2016 $600k-KU, $350k-LGE escalated by 2.5% across the plan)**
  This initiative is a reoccurring initiative to address circuits whose customers exceeded more than 7 outages in 2014 (CEMI is a one year look). The 2015BP included $675k for KU and $400k for LG&E. Similar to the CIFI program, total amounts vary by plan cycle based on the number of circuit impacted and by actual circuit performance across both utilities.

  This category covers individual, high value reliability based projects not covered under CIFI or CEMI work.

This new initiative to the plan is requested as incremental to the 2015BP beginning in 2016 (currently $117M spend over a 10 year planning window) to achieve the next step change in Reliability (SAIDI, SAIFI improvement) for Electric Distribution. This new initiative begins with the installation of SCADA controlled electronic reclosers which have an immediate reliability benefit on select circuits beginning in 2016. Later years of the program transition into building additional contingency into the system and the installation and turn-up of a Distribution Management System (DMS) allowing FLISR (automatic Fault Location, Isolation, and Service Restoration) of field devices. Funding for this program varies across the years depending on the type of work (Reclosers, Communication, Systems, Infrastructure to support Contingency) to be completed and available resources (both internal and external). Originally requested funding was set to complete full deployment in 7 years and has been scaled back to take 10 years for a full deployment.

Public Works, Mandated Relocations, and Customer Requested Projects (2016-$4.301M escalated 3% across the plan) covers alterations or relocation of distribution facilities to accommodate public works projects. It also provides funding for customer requested facility relocations prior to reimbursement by customers. This item is funded based on historical spend levels.

3. Maintain the Network Category
The Maintain the Network category includes capital blanket and project specific funding to maintain the condition of the system, replace failed or defective distribution and substation equipment, and specific projects to address aging infrastructure. Work specific to maintain, repair and replace distribution equipment covers distribution lines, substations, street lighting, distribution relocation work driven by transmission projects, and buildings and grounds.

- Repair and Replace Defective Equipment Blanket: Lines - (2016 $28.482M escalated 3% across the plan)
  This blanket item covers the cost of repairing and replacing defective distribution line material and equipment at each operations center. Maintenance and replacement of capacitors, poles, cable, vaults, and street lighting are included in this category. Funding is based on historical spend levels and is consistent with the 2015BP.

- Repair and Replace Defective Equipment Blanket: Substation Maintenance (2016 $3.104M, escalated 2.5% across the plan)
  This grouping of projects covers the cost of reactive repair and replacement of defective substation equipment at each operations center. Specifically, these projects include the replacement of failed equipment that cannot be effectively repaired, wildlife protection at unprotected stations, upgrades for compliance (NESC, cooling fans, oil containment capital repairs), building and grounds repairs, and minor improvements to reduce future maintenance/repair (transformer oil filtration, addition of lightning protection). Funding is up slightly from the 2015BP (2016 - $2,859k) primarily due to funding for the replacement of transformer fans.
• **Repair and Replace Defective Equipment Major Projects** *(2017-$220k)*
  This category covers major projects targeting defective equipment not covered under other categories. 2017 funding consists of two projects in different KU Operations to remove portions of the same out of service line (Roundhill) that has become an operational concern.

• **Purchase KU Portable Transformer** – *(2$4M total, 2017-$2.2M, 2018-$200k)*
  Funding for this project was in the 2015BP for 2017 as has now been split across 2017 ($2.2M) and 2018 ($200k). The purchase of an additional portable transformer for KU is needed to minimize outage duration caused by substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. The portable transformer is also needed to support maintenance work and an increasing work plan for substation transformer additions and replacements where transformers have to be removed from service as part of the construction process. The two KU portables are 19 and 62 years old and cannot be taken out of service for needed refurbishment due to the associated operational risk. The purchase of a large portable transformer for LG&E was completed in 2014.

• **Louisville Electric Operations Padmount Switchgear** – *(2$185k 2016, escalated 2.5% across the plan)*
  This program replaces aged and defective, high risk padmounted switchgear in underground commercial and large residential areas that has been identified during system inspections. The program is necessary to address increasing failure rates on highly deteriorated equipment and to replace equipment that cannot be effectively maintained.

• **Transmission Line Clearance (LG&E/KU $460k-2016, $628k-2017, $315k-2018)*
  This funding is used to cover the cost of undefined distribution line relocations and upgrades during the year driven by Transmission pole replacements, relocations and compliance directed (NERC) clearance projects. The project is generally funded at $300k/year split between LG&E and KU. One large identified project is also included (Shelbyville East Circuit 2522, 2016-$160k, 2017-$320k).

4. **Repair and Replace Aging Infrastructure**
  Aging infrastructure initiatives are based on available data by age, quantity in service, failure data, field experience, equipment specialty knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The age of the distribution system and increasing failure rates has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets that are beyond their expected life expectancy in areas where they have resulted in declining reliability. Robust system expansion in the 1960’s and 1970’s has created
substantially high groups of equipment and material with similar age and created the potential for very high failure rates in future years. Funding is included in the plan to continue major strategic infrastructure enhancement programs such as PILC Replacement, Pole Inspection and Treatment (PIPT), Legacy Substation Equipment and poor performing or high risk distribution facilities. An increase of approximately $1,400k is requested in 2016 compared to the 2015BP to reinstate several substation AI projects removed to meet reduction targets ($879k) and an additional $524k increase requested to fund additional cable rejuvenation work at LG&E across the plan. In years 2017, funding for small wire replacements is reduced by $700k compared to the 2015BP to better integrate this work with other reliability initiatives.

- **Pole Inspection and Treatment (LG&E/KU $11.2M, escalated 3% across the plan)**
  This program is funded at $10.9M in 2015 with a growth of 3% across the plan. This program covers the capital cost to extend the life of wood poles though preservative retreatment and reinforcement and covers the cost of defective or overloaded pole replacements identified under this program. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle). Funding for 2016-2020 is consistent with the 2015BP.

- **Paper Insulated Lead Covered (PILC) Cable Replacement (LG&E) – (2016-6.2M, escalated at 3% across the plan)**
  This program, started in 2013 involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability and safety concerns. Targeted cable is between 50 and 90+ years old. Program scope and funding has evolved, as follows:
  - 2013: Initiated program at $2M for 20 years to fund cable replacement (escalated by 2.5% per year).
  - 2014: BP included funding of $4M ($2M incremental escalated at 2.5% per year) to accelerate the program before adding an additional $2M ($6M total) to further accelerate the program and address higher than expected duct and manhole repairs and replacements.
  - 2015 – current: Continue funding at $6M level for 9 additional years with projected completion in 2023 (escalated by 3% per year) due to significant levels of manhole and ductline structure deterioration encountered during the program and to accelerate the program from a 20 year to approximately a 10 year replacement program. Shortening the program to 10 years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced. Funding is consistent with the 2015BP.

- **Louisville Electric Downtown Network Vault Structural Repairs – (2016-$283k, escalated 2.5% across the plan)**
This program targets replacement of defective vault tops (in sidewalks) and ventilated openings on downtown Louisville Network vaults that have deteriorated as a result of age and deicing salts. Deteriorated vault tops if not repaired increase the risk to the public and to the high cost network transformers and equipment located in vaults. Funding is consistent with the 2015BP level. Requested funding will typically allow the repair of 2-3 vault tops depending on the size of the vaults. There are currently 190 vaults in downtown Louisville.

- **Substation Asset Replacements (LG&E/KU) (2016-$2.7M, 2017-$2.4M, 2018-$2.4M).**
  This collection of programs covers the annual replacement of aged critical, maintenance intensive, unreliable substation equipment and/or equipment nearing obsolescence. These programs include equipment such as substation batteries, relays, 15kV power circuit breakers, Remote Terminal Units, cap and pin insulators, Load Tap Changers (LTC), and LTC Controllers. In 2012, Substation Construction and Maintenance identified a “Top 5 List” for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in service, field experience, and equipment specialty knowledge. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure program has been in past business plans but funding has varied due to available capital funding. Funding needs vary somewhat each year as program initiatives are completed and new ones are identified. Funding in the 2015BP for this group is 2016-$1,815k, 2017-$2,479k, 2018-$2,541k. Variance of an increase of $879k in 2016 is due to the restoration of several projects removed from the 2015BP to meet reduction targets including some legacy RTU’s, breakers (including 34kV), and Reinhausen LTC.

- **Substation Underground Cable Exits (LG&E) – ($1M-2016, escalated 2.5% across the plan)***
  This program began with funding of $1M in 2015 with a growth of 2.5% across the plan, and funds the replacement of PILC and the poorest performing solid dielectric substation exit cables. Substation exit cables have significant reliability implications because an entire circuit is lost until the location of the failure is identified. Targeted substation exits are between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts. Funding is consistent with the 2015BP.

- **Rear Easement Hardening (Combined LG&E/KU 2016-$1.7M, 2017 $1.1M-2017 escalated 3% across the balance of the plan)**
  This program covers the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of the program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, elimination of secondary, replacement of aged and defective equipment, and/or relocation of lines to less problematic areas. Funding requested in 2016 is consistent with the
2015BP. Funding in the 2016BP is reduced beginning in 2017 to approximately $500k for each utility to better integrate with other reliability base initiatives resulting in a variance reduction of $700k beginning in 2017.

- **Underground Cable Rejuvenation/Replacement (LG&E/KU) – (2016: $316k-KU, $1,051k-LG&E, escalated 2.5% across plan)**
  This program first piloted in 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are typically 40-45 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables by injecting dielectric fluid into the cable to restore the insulation strength in order to levelize the rate of future reactive failure replacements. These projects were in the 2015BP for $316k-KU and $527k-LGE. A requested increase of $524k is planned for the LG&E portion ($1,051-2016 total) in 2016 and beyond. Sufficient performance data is now available and shows a correlation between the start of the cable rejuvenation/replacement program and a slight decrease in failure rates of this vintage cable.

- **DT Network Vent Type Protector Replacement (LG&E)**
  This program, funded to begin at $500k in 2017 with a growth of 2.5% across the plan, initiates the replacement of aged network protectors that are not submersible rated for below ground application in vaults subject to flooding. The program will address the most critical of these assets and further enhance the integrity of the downtown network in conjunction with other network aging infrastructure programs (PILC, manhole lids, SCADA, AMI, etc.). Funding is consistent with the 2015BP.

- **Miscellaneous Aging Infrastructure - (2018-$380k)**
  This category covers individually identified high value aging infrastructure projects not included elsewhere. This category includes one project in 2018 to rebuild a severely deteriorated distribution line that has become a reliability and maintenance problem (Richmond Pine Hill to Livingston Line).

5. **Repair the Network Category**
   The repair the network category consists of four projects that cover the capital cost of damages by third parties, weather and non-weather related system repairs, and substation transformer repairs and rewinds. Storm related work is adjusted annually to 10 year averages. Other blanket items in this category are based on historical trends and volumetrics. As a category, variances to the 2015BP of approximately $330k in 2016 and beyond are the result of an increase in storm related restoration costs ($520k) partially offset by a reduction in Third Party Damages ($200k).
• **Third Party Damages – ($1.1M escalated 3% across the plan)**
  This blanket item covers the capital cost of unreimbursed repairs to utility facility caused by third parties. Funding is based on historical trends and volumetrics. The 2015BP contained $1,340k in 2016, escalated 3% across the plan resulting is a 2016BP reduction of approximately $200k (15%) across the plan.

• **Non-Weather System Restoration – ($8.3M-2016 escalated 3% across the plan)**
  This blanket item covers the cost of routine, non-storm related service restoration at all operations centers. Funding is based on historical trends and volumetrics. The 2015BP contained $8,294k in 2016, escalated 3% across the plan resulting in a minor 2016BP increase of approximately $10k across the plan.

• **Storm Restoration – (Combined LG&E/KU $3.2M-2016 escalated at CPI across the plan)**
  This blanket item funds the capital portion of storm related repairs. Funding is based on a 10 year average cost adjusted by the consumer price index. The 2015BP contained $2,696k in 2016, escalated 3% across the plan resulting in a 2016BP increase of approximately $520k (19%) across the plan. The variance is due to a change in the 10 year average resulting from a drop off of a relatively mild 2004 storm year from the rolling average and adding a higher 2014 year.

• **Substation Transformer Rewinds – (Combined LG&E/KU $2.5M-2016 escalated 3% across the plan)**
  This blanket item covers the cost of substation transformer repairs and the cost to rewind failed transformers for reuse. Funding is based on historical trends and volumetrics. The 2015BP contained $2,460k in 2016 and funding in the 2016BP is consistent with the 2015BP.

6. **Miscellaneous Network Category**
   The Miscellaneous category consists of miscellaneous capital projects not directly associated with connecting new customers or enhancing, maintaining or repairing the network. The Miscellaneous category consists of projects to address special needs when necessary, but generally consists of three main items, Tools and Equipment, Vehicles, and Equipment for Asset Management. No special projects are identified in the 2016BP. Significant variances to the 2015BP in years 2016-2019 (approx. $5M-$9M) are the result of accelerated purchases of Tier 1 vehicles.

• **Tools and Equipment – ($662k-2016 escalated 2-3% across the plan)**
This item funds the capital portion of tool and equipment purchases at all operations centers within EDO. Funding is based on historical trends supplemented as necessary to fund large, costly equipment when needed. Funding in 2016-2018 includes a minor reduction of approximate $50k (7%) each year compared to the 2015BP.

- **Vehicles – ($6,584k-2016, $5,818k, $1,729k-2018, $10,376k-2019, $1,271k-2020)**
  This item funds the purchase of vehicles within EDO. The 2015BP included $3M 2016-2019. Accelerated spending was planned in all years for the purchase of Tier 1 and Tier 2 vehicles as they exited the lease program. Funding was later reduced to the expected purchase of only Tier 1 vehicles after the initial plan was developed.

- **Equipment Purchases for Asset Management – ($300k 2016-2018, with escalation in 2019-2020)**
  This item funds the capital purchase of computer hardware and associated equipment such as plotters, survey equipment, and GPS units to support both Gas and Electric Operations. Funding in the 2015BP was $280k 2016-2017 and $286k in 2018 with a minor variance of a $20k (7%) increase requested in the 2016BP.
Electric Distribution Operations Business Plan  
Updated 7/21/2014

Background
The Electric Distribution Operations business plan consists of five strategic categories: Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous. Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual routine work and equipment purchases where such work cannot be defined in advance. Work is typically driven by short cycle, high volume work requests. Blanket funding is trended from historical actual expenses, volumetric trends, and local economic indicators and is adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, relocations, operation center driven reliability and enhancement work, and capital repairs or replacement of failed or damaged equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model and ranked using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability, and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program, Aging Infrastructure programs, Reliability Initiatives, and Capacity Enhancements are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value. The final plan is developed following reviews by EDO Directors and the VP, EDO and adjusted as necessary to address funding for key initiative projects and strategies.

Connect New Customer Category
The Connect New Customer category largely consists of blanket projects trended across the plan to cover the ongoing cost to extend electric facilities to serve new customers (or load) and associated costs of equipment such as distribution pole and padmount transformers. Known major projects to serve new loads, such as substation improvements for a single customer, are identified individually but do not occur in the plan every year. Funding for this category includes $59.3M in 2015, approximately 9% over the 2014 forecast mainly due to two large New Business substation projects. Excluding Major Projects, and Department of Energy (DOE) impacts on distribution line transformers in 2015 and 2016, funding increases approximately 5% across the balance of the plan (2.7% labor/materials, 2.0% growth). Major impacts are lower growth rates in recent years offset by higher than inflationary costs for connecting new customers as they move to urban centers for employment (economic growth is offset by churn). Cost impacts of the DOE mandated minimum efficiency standards for distribution line transformers are seen in 2015 and 2016. Two major new business projects have been identified in 2015, completion of the Lexington Delaplain 2 Substation (Aichi Forge) project ($500K 2015), and Danville Corning Substation ($750K 2015, $2603K 2016). One major new business project has been identified to start in 2016 at Delaplain 3 Substation ($825K 2016, $925K 2017).
Enhance the Network Category
The Enhance the Network category includes major and minor system improvements required to serve growing load and to enhance the reliability, safety and/or durability of the system. Mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) are also included in this category. Funding is included for a new initiative beginning in 2015 to address “At Risk” substations. “At Risk” substations are substations where all customers cannot be restored from alternate sources in the event of a transformer failure or unplanned outage and some customers may experience outages lasting 24-36 hours.

Enhancements to Meet Demand address current loading issues or expected overloads. Blanket funding for distribution operation centers is included to cover expected enhancements during each year and is funded at approximately $1.5M in 2015 and escalated 2.7% across the plan. The need for large, generally multiyear substation/circuit work projects are identified based on loading forecasted annually in the 10-year non-coincidental substation load forecast. Projects are placed in the plan so they are completed in the year the facility is expected to reach 100% of its rated capacity. The number of major new projects increases across the plan due to expected load growth (from the forecast), the reoccurrence of need for projects deferred in 2012 and 2013 due to slower load growth (Central Baptist, Russell Corner, Manslick, Paynes Mill) and known new major load additions (VA Hospital (LG&E), UK/Central Lexington Area (KU)). All major enhancement projects are summarized below:

2015 - 20 projects, $13.1M
- 1 – Substation/circuit completion (Lyndon South)
- 3 - New substations (Manslick, Shelbyville East, Lexington Area Major Project: includes American Ave 2)
- 3 – Substation upgrades (Central City 4KV, Central City South, Lexington Area Major Project: includes GE Lamp, Picadome 1, American Ave 1)
- 2 – Substation breaker upgrades (East Stone Gap, Lockport)
- 11 – Distribution circuit upgrades (Fariston circuit 0217, Haefling circuit 0055, Innovation Dr. circuit 0593, Lexington Area Major Project Distribution, Newtown Distribution, Versailles City circuit 505, Re-conductor Circuit 2220, Re-conductor circuit 2109, Milford 0935 re-conductor, Lyndon South, Manslick)

2016 - 14 projects, $12.9M
- 3 – Complete substations (Lexington Area Major Project Substation American Ave 2, Shelbyville East, Manslick)
- 4 - New substations (Hume Rd Substation Phase 2, Redhouse Substation, Lebanon East, Russell Corner)
- 1 - Substation upgrade (Simpsonville 1)
- 5 - Distribution circuit upgrades (Central City System, Lexington Area Major Project Distribution, Shelbyville East Distribution, Manslick, Russell Corner)
• 1 - Property purchase for new substation Mud Lane/Smyrna Area

2017 - 17 projects, $15.3M
• 5 - Substation completions (Hume Rd Substation Phase 2, Redhouse, Simpsonville 1, Lebanon East, Russell Corner)
• 2 – New substations (Tucker Station, Gene)
• 9 - Distribution circuit work projects (Central City, Fariston Circuit 0217, Hume Rd Phase 2, Redhouse Substation Project and Distribution, Re-conductor circuit 2215, Re-conductor circuit 2312, Russell Corner, Tucker Station, Gene)
• 1 - Property purchase for new substation Watterson/Fairmount Area

2018 - 20 projects, $22.5M
• 2 – Substation completions (Tucker Station, Gene)
• 8 - New substations (Paynes Mill Road, Georgetown Substation, Horse Cave Industrial 3, Versailles West, Days Branch, Stonewall 2, Old Henry, Floyd)
• 3 - Substation upgrades (Simpsonville 2, Russell Springs, Crocket)
• 1 - Substation relocation (Frankfort 34-69kV)
• 6 - Distribution circuits (Georgetown Distribution, Stonewall 2 Distribution, Tucker Station, Gene, Old Henry, Crocket distribution)

2019 - 34 projects, $28M
• 1 - Relocation completion (Frankfort 34-69kV)
• 10 – Substation completions (Paynes Mill, Simpsonville 2, Russell Springs, Georgetown, Stonewall, Horse Cave Industrial 3, Versailles West 2, Days Branch 12kV, Old Henry, Floyd)
• 5 - New substations (Salt Lick, Middlesboro Area, Mt Vernon, Lime Kiln, Fegenbush)
• 14 - Distribution circuits (Russell Springs, Paynes Mill Distribution, Shelbyville North, Horse Cave Distribution, Versailles West Distribution, Days Branch Distribution, Georgetown, Stonewall 2, Old Henry, Floyd, Lime Kiln, Fegenbush, Frankfort relocation distribution, Rogers Gap)
• 4 - Distribution circuit upgrades (Ashland Ave circuit 0050, Ashland Ave circuit 0111, Oxford circuit 0471, Black Branch)

In addition to capacity enhancement projects necessary to the meet the demand of existing customers, other projects are targeted at enhancing non-load driven needs of the system. Three major projects included in the Enhancement to Meet Demand category address improving response to critical substation transformer failures or enhancing monitoring and control at substations. They include:

• **At Risk Substations**, $2.5M 2015-2019 with a 2.5% increase annually. This initiative includes substation/circuit upgrades, capacity additions and enhancements at high concern substations for the purpose of adding contingency for a substation transformer failure. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/ouages due to lack of contingency from nearby stations. This initiative is separate from capacity additions to serve
existing customers and was added as an incremental initiative in the 2014 BP. Funding will provide for completing two projects over two years. Projects identified for 2015-2016 include a transformer addition (Lakeshore 3) and a transformer upgrade (Innovation Drive).

- **KU spare transformers**, $1M each in 2017 and 2018. This funding will be used to increase the spare stock of KU transformers available for the replacement of failed units. Additional spares will be necessary to address the increasingly aging fleet of substation transformers in the KU areas.

- **KU SCADA Expansion**, $500K across the plan to install equipment for load monitoring and equipment monitoring and control at high value KU substations that currently lack any SCADA capabilities. Currently, only 29% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped. The 2014 BP included SCADA in 2018 at $5M. Funding was reduced and spread across the plan to be in line with the resources available to complete this core skill work.

Additional projects are designed to enhance the safety or integrity of the system, including:

- **Downtown Louisville Network Manhole Lid Replacement** ($865K 2015 and $212K in 2016). This program, started in 2013, enhances public safety in downtown Louisville by replacing conventional manhole lids with lids that are designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. The program is focused on manholes located in the downtown Louisville network area. This funding will complete the program in 2016.

- **Lexington Area Manhole Lid Replacement** ($98K in 2015 and $52K in 2016). This program, started in 2013, enhances public safety in the central Lexington area by replacing conventional manhole lids with lids designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. This funding will complete the program in 2016.

Enhancements for Reliability includes blanket funding across the plan to address upcoming reliability issues at the operations centers and unplanned small scale projects to target reliability improvement and/or safety and resiliency of the system. This blanket covers general distribution reliability improvements driven by customer complaint and abrupt downturn in reliability performance (KU-LG&E $2,131K in 2015, escalated by 2.7% through 2019).

Also included are ongoing programs to improve worst circuit performance through CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) projects and high value smaller reliability project work evaluated using the AIS financial model. Funding levels in the 2014 BP were adjusted to reflect the current number of circuits in each category and escalated across the plan.

- **CIFI (worst) Circuits – Level 1**: Circuits whose 5 year average SAIFI performance exceeds the average circuit performance by > 4 standard deviations (KU $390K in 2015, escalated by 2.7% through 2019) (LG&E $1,170K in 2015, escalated by 2.7% through 2019).
Attachment to Response to AG-1 Question No. 440 d Att 3
John K. Wolfe

- **CIFI (worst) Circuits – Level 2**: Circuits whose 5 year average SAIFI performance exceeds the average circuit performance by > 3 standard deviations (KU $650K in 2015, escalated by 2.7% through 2019) (LG&E $1,430K in 2015, escalated by 2.7% through 2019).
- **CIFI (worst) Circuits – Level 3**: Circuits whose 5 year average SAIFI performance exceeds the average circuit performance by > 2 standard deviations (KU $1,950K in 2015, escalated by 2.7% through 2019) (LG&E $3,640K in 2015, escalated by 2.7% through 2019).
- **CEMI>5**: Circuits whose customers exceeded more than 7 outages in 2013 (KU $675K in 2015, escalated by 2.7% through 2019) (LG&E $400K in 2015, escalated by 2.7% through 2019).

**Maintain the Network Category**

The Maintain the Network category includes capital blanket and project specific funding to maintain the condition of the system, replace failed or defective distribution and substation equipment and specific projects to address aging infrastructure. Work specific to maintain, repair and replace distribution equipment covers distribution lines, substations, street lighting, distribution relocation work driven by transmission projects, and buildings and grounds. Blanket funding for repair/replace blankets is $27.2M in 2015 and is escalated by 2.7% across the plan.

Repair and replace funding under Maintain the Network includes the following major projects:

- **Purchase KU Portable Transformer**, $2.4M in 2017. The purchase of additional portable transformer for KU is needed to minimize outage duration caused by substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. The portable transformer is also needed to support maintenance work and an increasing work plan for substation transformer additions and replacements where transformers have to be removed from service as part of the construction process. The purchase of a large portable transformer for LG&E was completed in 2014.
- **Distribution Capacitors (LG&E/KU)**. This new program, funded at $278K in 2015 through 2018 (increasing to $287K in 2019) provides for the installation of distribution capacitors targeted for transmission system power factor improvement. This work had been funded in the past by Transmission. Incremental Distribution Capital funding has been offset by the transfer of capital funding from Transmission.

New to the plan starting in 2015 is funding for two reoccurring projects to address known defective equipment and infrastructure identified through facility inspections.

- **Louisville Electric Operations Padmount Switchgear**. This program, funded at $180K in 2015 with a growth of 2.5% across the plan, is to replace aged and defective padmounted switchgear in underground commercial and large residential areas that has been identified during system inspections. The program is necessary to address increased failure rates on highly deteriorated equipment and to replace equipment that cannot be effectively maintained.
- **Louisville Electric Downtown Network Vault Structural Repairs**. This program, funded at $276K in 2015 with a growth of 2.5% across the plan, replaces defective vault tops (sidewalks) and
ventilated openings that have deteriorated as a result of age and deicing salts. Deteriorated vault tops are at risk of caving in from occasional vehicle loading.

Aging Infrastructure Initiatives:

Aging infrastructure initiatives are based on available data by age, quantity in service, failure data, field experience, equipment specialty knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The age of the distribution system and increasing failure rates has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets that are beyond their expected life expectancy in areas where they have resulted in declining reliability. Robust system expansion in the 1960’s and 1970’s has created substantially high groups of equipment and material with similar age and created the potential for very high failure rates in future years. Key components of the program include:

- **Pole Inspection and Treatment (LG&E/KU).** This program is funded at $10.9M in 2015 with a growth of 3% across the plan. This program covers the capital cost to extend the life of wood poles through retreatment and reinforcement and covers the cost of defective or overloaded pole replacements identified under this program. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle).

- **Paper Insulated Lead Covered (PILC) Cable Replacement (LG&E).** This program, started in 2013 involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability concerns. Targeted cable is between 50 and 90+ years old. Program scope and funding has evolved, as follows:
  
  - 2013 – Initiated program at $2M for 20 years to fund cable replacement (escalated by 2.5% per year).
  - 2014 – BP included funding of $4M (escalated at 2.5% per year) to accelerate the program before adding an additional $2M ($6M total) to further accelerate the program and address higher than expected duct and manhole repairs and replacements.
  - 2015-2019 – Continue funding at $6M level ($2M incremental over 2014 BP) for 9 additional years (escalated by 2.5% per year) due to significant levels of manhole and ductline structure deterioration encountered during the program and to move the program from a 20 year to a 10 year replacement program. Shortening the program to 10 years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced.

- **Substation Asset Replacements (LG&E/KU).** This collection of programs covers the annual replacement of critical, maintenance intensive, and/or unreliable substation equipment (substation batteries, relays, 15kV power circuit breakers, Remote Terminal Units, and Load Tap Changers). In 2012, Substation Construction and Maintenance identified a “Top 5 List” for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in
service, field experience, and equipment specialty knowledge. O&M considerations were cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure program has been in past business plans but funding has varied due to pressures on capital funding. The program is in the plan at $2.6M annually with a growth of 2.5% across the plan.

- **Substation Underground Cable Exits (LG&E).** This program, funded at $1M in 2015 with a growth of 2.5% across the plan, covers the replacement of PILC and poor performing solid dielectric substation exit cables. Targeted substation exits are between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts.

- **Rear Easement Hardening (LG&E/KU).** This program, funded at $1662K ($500K-LG&E, $1.162M-KU) in 2015 with a growth of 2.5% across the plan, covers the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of the program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guy ing, and elimination of secondary, replacement of aged and defective equipment or relocation of lines to less problematic areas.

- **Underground Cable Rejuvenation/Replacement (LG&E/KU).** This program piloted since 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are 40-50 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables in order to levelize future reactive failure replacement costs. It is funded at $822K per year ($514K-LG&E, $308K-KU) with a growth of 2.5% across the plan.

- **DT Network Vent Type Protector Replacement (LG&E).** This program, funded at $500K in 2017 with a growth of 2.5% across the plan, initiates the replacement of aged network protectors that are not submersible rated for below ground application in vaults subject to flooding. The program will address the most critical of these assets and further enhance the integrity of the downtown network.

- **LEO WS1330 Cable Replacement.** This $274K project in 2015 is required to improve service reliability to Central High School, Taylor Elementary School, and Mount Lebanon Personal Care Center. Service reliability has declined due to multiple underground cable failures.

- **KU Substation Lightning Protection project ($50K annually with a 2.5% increase across the plan).** This program retrofits existing KU substations with lightning protection to improve reliability and reduce the potential for failure of high value substation equipment and transformers. All LG&E substations and new KU substations have lightning protection.

- **KU Substation Wildlife Protection project, ($228K with a 2.5% increase across the plan) provides for the installation of wildlife protection at KU open air substations with exposed energized components. Outages caused by wildlife in substations are high impact events resulting in an outage for all customers and the potential to damage high value substation equipment and transformers.
**Repair the Network Category**
$11.9M in 2015 escalated across the plan. Repair the Network consist of blanket projects that address expected expenses associated with system restoration (storm and non-storm), repairs of third party damage, and substation power transformer repairs and rewinds.

**Miscellaneous Network Category**
Miscellaneous Network covers expenses for tooling, equipment and vehicles with funding of approximately $4M 2015-2017 and $6.5M in 2017-2019. This includes the multi-year EDO Tiered Capital Strategy for heavy duty, light duty, and yellow equipment.
Electric Distribution Operations Business Plan

**Background**
The Electric Distribution Operations business plan consists of five strategic categories: *Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous*. Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual work and equipment purchases where such work cannot be defined in advance. Blanket funding is trended from historical actual expenses and adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, operation center driven reliability and enhancement work, and capital repairs or replacement of failed equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability, and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program, Aging Infrastructure programs, Reliability Initiatives, and Capacity Enhancements are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value.

**Connect New Customer Category**
The Connect New Customer category largely consists of blanket projects trended across the plan to cover the ongoing cost to extend electric facilities to serve new customers (or load) and associated costs of equipment such as distribution pole and padmount transformers. Known major projects to serve new loads, such as substation improvements for a single customer, are identified individually but do not occur in the plan every year. Funding for this category includes $55.2M (2014) and increases approximately 5-8% across the plan (including the impact of specific projects). Major impacts are lower growth rates in recent years offset by higher than inflationary costs for connecting new customers as they move further from traditional urban centers and increasing costs for distribution transformers as a result of the DOE efficiency standards. One major new business project in 2015 is required to serve new University of Kentucky dormitory load.

**Enhance the Network Category**
The Enhance the Network category includes major and minor system improvements required to serve growing load, and to enhance the reliability, safety and/or durability of the system. Mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) are also included in this category.

Specifically, Enhancements to Meet Demand address current loading issues or expected overloads. Blanket funding for distribution operation centers is included to cover expected enhancements during each year. Large, generally multiyear substation/circuit projects are identified based on loading
forecasted annually in the 10 year non-coincidental substation load forecast. Projects are planned for service in the year the facility is expected to reach 100% of its rated capacity. The number of major new projects increases across the plan due to expected load growth (from the forecast), the reoccurrence of need for projects deferred in 2012 and 2013 due to slower load growth (Central Baptist, Russell Corner, Manslick, Paynes Mill) and known new major load additions (VA Hospital, UK). Larger enhancement projects are summarized below:

2014-3 projects, $7.3M
1-completion (Hume Rd), 1-property acquisition (Central Baptist), 1-transformer addition (Lyndon South).

2015-6 projects, $11.2M
1-completion (Lyndon South), 2-new substations (Manslick, Paynes Mill), 2-transformer upgrades (Simpsonville #1, Atoka), 1-transformer addition (Stonewall), West High Street Substation upgrade ($1M - classified as new business).

2016-6 projects, $10.2M
5-completions (Manslick, Paynes Mill, Simpsonville, Atoka, Stonewall), 1-new substation (Lime Kiln).

2017-10 projects, $15.1M
1-completion (Lime Kiln), 5-new substations (Central Baptist, Lexington, Gene Street, Russell Corner, Shelbyville), 4-transformer upgrades (Owenton 4kV, Russell Springs, Shelby City, Simpsonville #2).

2018-14 projects, $19.8M
8-completions (Central Baptist, Lexington, Gene Street, Owenton, Russell Corner, Russell Springs, Shelbyville, Simpsonville #2), 3-substation upgrades (Crockett, Days Branch, Old Henry), 1-transformer addition (American Ave), 2-new substations (Floyd, Horse Cave area).

In addition to capacity enhancement projects necessary to meet the demand of existing customers, other projects are targeted at enhancing non-load driven needs of the system. Three new projects (incremental to the 2012 Business Plan (BP)) included in the Enhancement to Meet Demand category address improving response to critical substation transformer failures. They include:

- **Purchase LG&E and KU Portable Transformers**, 2014-LGE $2.5M and 2017-KU $2.5M. The purchase of additional portable transformers is needed to minimize outage duration caused by substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. These portable transformers are also needed to support maintenance work and an increasing work plan for substation transformer additions and replacements where transformers have to be removed from service as part of the construction process.

- **KU spare transformers**, $1M each in 2017 and 2018. This funding will be used to increase the spare stock of KU transformers available for the replacement of failed units. Additional spares
will be necessary to address the increasingly aging fleet of substation transformers in the KU areas.

- **At Risk Substations**, $2.5M 2015-2018 with a 3% increase annually. This project includes substation/circuit upgrades, capacity additions and enhancements at high concern substations for the purpose of adding contingency for a substation transformer failure. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from nearby stations. This initiative is separate from capacity additions to serve existing customers. Funding will provide for one project per year. Targeted stations in the plan for contingency enhancements include Versailles 4 kV, Georgetown 4 kV, Watterson 12 kV, Highland 12 kV, and Harmony Landing (12kV).

Additional projects are designed to enhance the safety or integrity of the system, including:

- **Downtown Network Manhole Lid Replacement** ($1M 2014 and 2015 – this is $500k incremental to the 2012 BP plan to accelerate the existing program from a 5 year program to a 2.5 year program). This program started in 2013 and enhances public safety in high pedestrian areas and covers replacement of conventional manhole lids with lids that are designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole.

- **KU Substation Lightning Protection project** ($50K annually with a 3% increase across the plan). This program retrofits existing KU substations with lightning protection to improve reliability and reduce the potential for failure of high value substation equipment and transformers. All LG&E substations and new KU substations have lightning protection. This program has been inconsistently funded in past years and is incremental to the 2012 BP.

Enhancements for Reliability include blanket funding to address upcoming reliability issues at the operations centers and defined projects to target reliability improvement and/or safety and resiliency of the system. Included are ongoing programs to improve worst circuit performance through CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) projects and high value smaller project reliability work evaluated using the AIS financial model.

One project also included in the Enhancements for Reliability category is the installation of a system to gather load data in the downtown network.

- **Network Load Monitoring (LG&E) $750K (2014)** is incremental to the 2012 BP. This project is necessary to extend the benefits of the completion of the downtown network SCADA project scheduled for completion in 2013. This system will provide critical data necessary for electric system planning of the network under normal and contingency conditions.

The 2012 BP plan also specifically includes $5M in 2017 and 2018 to expand the KU SCADA system. Currently, only 29% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped.

**Maintain the Network Category**
The Maintain the Network category includes capital blanket and project specific funding to replace failed or defective distribution and substation equipment and specific projects to address aging infrastructure. Blanket funding is trended across the plan and key funding areas include distribution lines, substations, street lighting, network vault top replacement and buildings and grounds.

Specifically, aging infrastructure initiatives are based on available data on age, quantity in service, failure data, field experience, equipment specialty knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The significant aging of the distribution system has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets nearing or beyond their expected life expectancy in areas where they have resulted in declining reliability. Robust system development in the 1960’s and 1970’s has created substantially high groups of equipment and material with similar age and created the potential for very high failure rates in future years. Key components of the program include:

- **Pole Inspection and Treatment (LG&E/KU).** This program is funded at $10.5M in 2014 with a growth of 3% across the plan. This program covers the capital cost to extend the life of wood poles through retreatment and reinforcement and covers the cost of defective or overloaded pole replacements. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle).

- **Paper Insulated Lead Covered (PILC) Cable Replacement (LG&E).** This program, started in 2013 ($2M) involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability concerns. Targeted cable is between 50 and 90+ years old. PILC replacement is funded in the proposed 2013 BP at $4M each year with a growth of 3% across the plan. This includes $2M incremental annually to the 2012 BP to reduce the program from a 20 year to a 10 year replacement program. Shortening the program to 10 years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced.

- **Substation Asset Replacements (LG&E/KU).** This program covers the annual replacement of critical, maintenance intensive, and/or unreliable substation equipment (substation batteries, relays, 15kV power circuit breakers, Remote Terminal Units, and Load Tap Changers). In 2012, Substation Construction and Maintenance identified a “Top 5 List” for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in service, field experience, and equipment specialty knowledge. O&M considerations were cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure program has been in past business plans but has been cut or substantially reduced due to pressures in capital funding. The program is in the plan at approximately $3M annually with a growth of 3% across the plan.

- **Substation Underground Cable Exits (LG&E).** This program is funded at $1M in 2015 with a growth of 3% across the plan. This program covers the replacement of PILC and poor performing solid dielectric and underrated substation exit cables. Targeted substation exits are
between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts. The Substation Underground Cable Exits (LG&E) program has been in past business plans but has been cut due to pressures in capital funding.

- **Rear Easement Hardening (LG&E/KU).** This program covers the rehabilitation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of the program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, elimination of secondary and replacement of aged and defective equipment. This program is incremental to the 2012 BP and is funded at $2M per year beginning in 2015 with a growth of 3% across the plan. The Rear Easement Hardening program has been in past business plans but has been cut due to pressures in capital funding.

- **Underground Cable Rejuvenation/Replacement (LG&E/KU).** This program piloted since 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are 40-50 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables to levelize future failure replacement costs. It is funded at $800k per year ($500k-LG&E, $300k-KU) with a growth of 3% across the plan.

- **DT Network Vent Type Protector Replacement (LG&E).** This program is in the plan in 2017/2018 and is intended to begin the incremental replacement of critical network protectors that are not submersible rated where they are installed below ground and subject to flooding. The program will be annually funded at $1M a year beginning in 2017 to address the most critical of these assets and further enhance the integrity of the downtown network.

**Repair the Network Category**
Repair the Network consist of blanket project that address expected expenses associated with system restoration (storm and non-storm), repairs of third party damage, and substation transformer repairs and rewinds.

**Miscellaneous Network Category**
Reliable DC power is needed in order to improve public safety from catastrophic manhole explosions and lower risk of fire.

Improving reliability on 26 KU circuits that have customers experiencing multiple interruptions. The existing conductor from Ivor Road to the city of California out have fallen down. Safety/Liability issue.

A proactive asset replacement program to replace aged, deteriorating paper insulated lead covered (PILC), secondary underground cables in the LG&E Downtown Secondary Network. This system will permit real-time access to the system while it is operating, ensuring that proper operation of the protection system.

Failed units will require replacement to ensure continuity of service.

Replace aging acsr 12kv primary. The existing conductor from Ivor Road to the city of California out have fallen down. Safety/Liability issue.

Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare parts are becoming difficult to find. Replace 2 breakers per year until these 5 have failed. Failed units will require replacement to ensure continuity of service.

Replace aging 500-600 kcmil wire. Five units are 60-70 years old, and spare parts are becoming difficult to find. Replace 2 breakers per year until these 5 have failed. Failed units will require replacement to ensure continuity of service.

Replace aged Murray batteries. Several units are over 20 years old, and spare parts are becoming difficult to find. Replace 2 batteries per year until these 2 have failed. Failed units will require replacement to ensure continuity of service.

Failed units will require replacement to ensure continuity of service.

Several chargers are becoming unreliable and should be replaced as needed. Failed units will require replacement to ensure continuity of service.

Several banks are deteriorated. Several chargers are becoming unreliable and should be replaced as needed. Failed units will require replacement to ensure continuity of service.
Replace the 600 amp breaker with a 1200 amp breaker on Ckt 4702. See related 2013 Project.

Replace an existing 600 amp breaker with a 1200 amp breaker on P&G Ckt 0066 plus 2013 Project.

Increase the capacity of the substation regulators in order to fully utilize the Trim Master substation transformer capacity. See related substation Project.

Remove existing recloser and install new recloser(s) on Adams circuit 0453. The 2013 Project.

Reconductor approximately 13000’ of 266 acsr with 397 acsr between the Paris 12 kv and Central City South 12kv. The distribution system is fed from two dual voltage substations: Central City and Russell Corner Substations. Remove 1- 100KVA 4kV regulator bank at the roadway distribution transformers. See Manslick Substation expansion for detail.

Circuit work at Manslick Substation. See attached business case document.

The purpose of this project is to convert the Hartford 4kv system to 12kv. Replace 8 straight 4KV radial distribution transformers, 3KV capital insulations and insulators (with 3 phase isolation). The project is completed at the start of 2013. Distribution: $50,000.

The purpose of this project is to build a new 138/13.09 kV, 10.5 MVA substation on currently owned property or a new site in Russell Corner, KY along US 42 or US 53. The substation is needed to relieve an overload projected for winter 2013-2014. The site is a mountain side to the shoulder of hwy. Where the line is currently located frequiently #2ACSR on telephone company owned poles.

The purpose of this project is to convert the Hartford 4kv system to 12kv. The distribution system is fed from two dual voltage substations: Central City and Russell Corner Substations. Remove 1- 100KVA 4kV regulator bank at the roadway distribution transformers. See Manslick Substation expansion for detail.

Improve reliability on one(1) Level 1 Circuits ID’d for Improvement (CIFI) at LGE. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where the circuit’s average Contribution to System SAIFI exceeds the average system circuit CIFI circuits have a long term (5 year) poor SAIFI performance record where the circuit’s average Contribution to System SAIFI exceeds the average system circuit

Improve reliability on five(5) Level 1 Circuits ID’d for Improvement (CIFI) at KU. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where the circuit’s average Contribution to System SAIFI exceeds the average system circuit

Breaker, remove one 15kV 600 amp breaker, circuit 343 on the Richmond Industrial main breaker, circuit breakers, and associated equipment on substation property (with 3 phase isolation). The project is completed at the start of 2013. Distribution: $50,000.

The purpose of this project is to build a new 138/13.09 kV, 10.5 MVA substation on currently owned property or a new site in Russell Corner, KY along US 42 or US 53. The substation is needed to relieve an overload projected for winter 2013-2014. The site is a mountain side to the shoulder of hwy. Where the line is currently located frequiently #2ACSR on telephone company owned poles.

The purpose of this project is to build a new 138/13.09 kV, 10.5 MVA substation on currently owned property or a new site in Russell Corner, KY along US 42 or US 53. The substation is needed to relieve an overload projected for winter 2013-2014. The site is a mountain side to the shoulder of hwy. Where the line is currently located frequiently #2ACSR on telephone company owned poles.

The purpose of this project is to build a new 138/13.09 kV, 10.5 MVA substation on currently owned property or a new site in Russell Corner, KY along US 42 or US 53. The substation is needed to relieve an overload projected for winter 2013-2014. The site is a mountain side to the shoulder of hwy. Where the line is currently located frequiently #2ACSR on telephone company owned poles.

The purpose of this project is to convert the Hartford 4kv system to 12kv. Replace 8 straight 4KV radial distribution transformers, 3KV capital insulations and insulators (with 3 phase isolation). The project is completed at the start of 2013. Distribution: $50,000.
The SCIENCE HILL SUB TRANSFORMER IS CURRENTLY BEING WORKED ON BY ABB. WE

REPLACE 10,000 FEET OF #1STR COPPER WITH 397 ACSR AND 2/0 ACSR NEUTRAL.

REPLACE 10,000 FEET OF #1STR COPPER WITH 397 ACSR AND 2/0 ACSR NEUTRAL.

INSTALL APPROXIMATELY 3000 FEET OF #3 STRAW WITH 397 ACSR FROM SUB 69 KV TO SUB 788.

REPLACE 3000 FEET OF #2ACSR WITH 397 ACSR.

REPLACE APPROXIMATELY 2000 FEET OF 2/0 ACSR WITH 397 ACSR.

REPLACE 10000 FEET OF #1STR COPPER WITH 397 ACSR AND 2/0 ACSR NEUTRAL.

REPLACE 13000 FEET OF #1STR ACSR WITH 397 ACSR AND 2/0 ACSR NEUTRAL.

REPLACE 13000 FEET OF #1STR ACSR WITH 397 ACSR AND 2/0 ACSR NEUTRAL.

REPLACE 10000 FEET OF 1/0 ACSR WITH 397 ACSR FROM SUB 404 TO 860-2 IN

REPLACE 10000 FEET OF 2/0STR COPPER WITH 397 ACSR AND 2/0 ACSR NEUTRAL.

REPLACE 10000 FEET OF 1/0ACSR WITH 397ACSR FROM SUB 404 TO 860-2 IN

INSTALL 5000 FEET OF 397 ACSR.

REPLACE 3000 FEET OF #2ACSR WITH 397 ACSR.

INSTALL 3000 FEET OF 397 ACSR.

REPLACE 10000 FEET OF 2/0STR COPPER WITH 397 ACSR AND 2/0 ACSR NEUTRAL.

REPLACE 3000 FEET OF 266.8 ACSR WITH 397 ACSR.

REPLACE 10000 FEET OF #1STR COPPER WITH 397 ACSR AND 2/0 ACSR.

REPLACE 3000 FEET OF 266.8 ACSR WITH 397 ACSR.

REPLACE 3000 FEET OF 266.8 ACSR WITH 397 ACSR.

REPLACE APPROXIMATELY 9000 FEET OF #1STR COPPER WITH 397 ACSR.

REPLACE APPROXIMATELY 9000 FEET OF #1STR COPPER WITH 397 ACSR.

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INSTALL APPROXIMATELY 5000 FEET OF 397 ACSR.
A reliable DC power is needed in order to...
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<th>Project</th>
<th>2014</th>
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<td></td>
<td>CIFI (worst) Circuits - Level 3</td>
<td>Improve reliability on 45 UGE circuits that have Customers Experiencing Multiple Interruptions (CMI) and in the future</td>
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<td>CIFI (worst) Circuits - Level 2</td>
<td>Improve reliability on 35 UGE circuits for Improvement (LGE) or NLU, Level 2 CIFI circuits have a long term (5 year) poor SARI performance record where the circuits average</td>
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<td>CIFI (worst) Circuits - Level 1</td>
<td>Improve reliability on 44 UGE circuits for Improvement (LGE) or NLU, Level 1 CIFI circuits have a long term (5 year) poor SARI performance record where the</td>
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<td>CIFI (worst) Circuits - Level 1</td>
<td>Improve reliability on 20 Level 3 Circuits for Improvement (LGE) or NLU, Level 1 CIFI circuits have a long term (5 year) poor SARI performance record where the circuits average</td>
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<td>CIFI (worst) Circuits - Level 1</td>
<td>Improve reliability on 24 Level 3 Circuits for Improvement (LGE) or NLU, Level 1 CIFI circuits have a long term (5 year) poor SARI performance record where the circuits average</td>
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<td>CIFI (worst) Circuits - Level 1</td>
<td>Improve reliability on 28 Level 3 Circuits for Improvement (LGE) or NLU, Level 1 CIFI circuits have a long term (5 year) poor SARI performance record where the circuits average</td>
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<td>SCM Bond 1 Breaker</td>
<td>Install a new circuit breaker in the Bond substation in order to divide the load on 1, 2, 6, 860. See related distribution project. Bond 1, 2, 6, 860 breaker 999</td>
<td>75</td>
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<tr>
<td>2962</td>
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<td>SCM Bond 1 Distribution</td>
<td>Install 3, 397 ACRs on the substation to the substation to Article 26 for additional circuit distribution provides reliability benefit. See related substation project. SCM Bond 1, 2, 6, 860 breaker 999, SCM Bond 1, 2, 6, 860 breaker 999</td>
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<td>SCM CanAm AG Smith Top Circuit Upgrade</td>
<td>Install additional GIS switchgear to improve reliability. SCM Bond 1, 2, 6, 860 breaker 999, SCM Bond 1, 2, 6, 860 breaker 999</td>
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<td>2964</td>
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<td>SCM Central Baptist Area Substation Project</td>
<td>Install circuit improvements (minimum three new circuits) as needed in order to provide adequate substation exit circuit capacity for the associated Central Baptist Area Substation Project. SCM Bond 1, 2, 6, 860 breaker 999</td>
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<tr>
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<td>SCM Central Baptist Area Substation</td>
<td>Install a new 20/57.3 MVA transformer, steel structures, main breaker circuit breaker).</td>
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<td>2966</td>
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<td>SCM LGE BDD Diff Relay</td>
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<td>SCM LGE BDD Diff Relay</td>
<td>SCM LGE BDD Diff Relay</td>
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AIS Start

1. Improve reliability on 12 Level 2 Circuits ID'd for Improvement (CIFI) at KU. Level 2 Circuit's average Contribution to System SAIFI exceeds the average system circuit's average Contribution to System SAIFI.

2. A proactive asset replacement program to replace aged, deteriorating paper stock. Standard life expectancy is 20 yrs. Due to maintenance practices, we have been able to extend life of these units to 35 yrs. However, we have experienced failures from an acknowledged design flaw. The inadvertent trip of a phase/grounded feeder causes the breaker to de-energize the feeder and fail to re-energize upon the removal of the ground. These devices require an operator to determine the status of the feeder and take corrective actions. The majority of these switches have been replaced in recent years, however, some remain in service. The 2015 budget is to replace approximately 300 switches.

3. The KU system (Central, Pineville, and Earlington) contains numerous legacy GE Type VIB vacuum breakers from the 1970s. The mechanisms on these breakers have been replaced however, the switches are continuing to fail. These switches have a limited service life of 20 years. The 2015 budget is to purchase and install New VIB switches. The replacement of these switches will allow us to bring our distribution infrastructure in better compliance with the current Technical Standards. The cost of these switches is $20,000 each.

4. The majority of KU Distribution Substations in or near the Lexington area have early 1970's G.E. Type 2400 GIL switches. These switches have a service life of 20 years. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. Several units were manufactured circa 1950, and spare parts are becoming difficult to find. Repairs/replacements on control house buildings, fire preventions systems and other general capital improvements to substation grounds and Regulator Controls with new style Regulator Controls.

5. To provide funding for various repairs and upgrades that arise throughout the year. Often, this work will be associated with an equipment failure or a tripping event. Various repairs/replacements on control house buildings, fire preventions systems and other general capital improvements to substation grounds and Regulator Controls.

6. The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this project.

7. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. These relays are critical in the operation of the protection system. Failed units will require replacement to ensure proper operation of automatic protection systems and reliable operations per year. This will ensure continuity of service to the area served by these circuits.

8. The KU system (Central, Pineville, and Earlington) contains numerous legacy GE Type VIB vacuum breakers from the 1970s. The mechanisms on these breakers have been replaced however, the switches are continuing to fail. These switches have a limited service life of 20 years. The 2015 budget is to purchase and install New VIB switches. The replacement of these switches will allow us to bring our distribution infrastructure in better compliance with the current Technical Standards. The cost of these switches is $20,000 each.

9. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. These relays are critical in the operation of the protection system. Failed units will require replacement to ensure proper operation of automatic protection systems and reliable operations per year. This will ensure continuity of service to the area served by these circuits.

10. The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this project.

11. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. These relays are critical in the operation of the protection system. Failed units will require replacement to ensure proper operation of automatic protection systems and reliable operations per year. This will ensure continuity of service to the area served by these circuits.

12. The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this project.

13. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. These relays are critical in the operation of the protection system. Failed units will require replacement to ensure proper operation of automatic protection systems and reliable operations per year. This will ensure continuity of service to the area served by these circuits.

14. The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this project.

15. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. These relays are critical in the operation of the protection system. Failed units will require replacement to ensure proper operation of automatic protection systems and reliable operations per year. This will ensure continuity of service to the area served by these circuits.

16. The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this project.

17. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. These relays are critical in the operation of the protection system. Failed units will require replacement to ensure proper operation of automatic protection systems and reliable operations per year. This will ensure continuity of service to the area served by these circuits.

18. The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this project.

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21. Many legacy CA relays require replacement. Many have tested out of tolerance and have failed. These relays are critical in the operation of the protection system. Failed units will require replacement to ensure proper operation of automatic protection systems and reliable operations per year. This will ensure continuity of service to the area served by these circuits.
Install circuit improvements (minimum three new circuits) as needed in order to maintain safe and satisfactory service to our customers. This includes replacing oil circuits, installing new wood poles, performing underground cable work, and replacing legacy LTCs. This will improve reliability on our network.

Cables aging and deteriorating into the ground or in the air are replaced at various locations throughout the service area to improve reliability.

Installation of underground stations to address growth and new development, plus upgrade the existing stations. Action is needed because the peak load is projected to be 105% in 2015, and all customers are impacted.

Substation surveys have turned up many NESC compliance concerns such as fences, overhead wires, and trees too short and vertical electrical clearances not adequate. This miscellaneous project is to correct these concerns.

An infrastructure improvement program to inspect, test, and repair distribution wood poles on the LG&E system. The program inspects poles, assesses the condition, then requests repair work as needed. The work is performed by LG&E distributing engineers.

An underground system is installed to provide service to a new customer. The installation consists of an underground cable to a property line and a transformer for service.

Phase installation of underground cables in areas that are being redeveloped. The new underground cables provide circuits to serve large commercial retail developments.

Perform underground work in areas that are being redeveloped. The new underground cables provide circuits to serve large commercial retail developments.

The old BDD relays require upgrades. We have found the BDD relays older than 30 years of age. The relays have reached end of life and do not meet modern standards for protection.

Proactive asset replacement program to replace or rejuvenate aged, poor performance underground substations, customers, and associated equipment in the Stonewall Substation. Load transfers will be required.

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<td>Ongoing project to replace Legacy LGC and Regulator Controls with new style</td>
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<td>Purchase and Install new LGC and Regulator Controls. Remove and Retire Legacy equipment</td>
<td>Ongoing project to replace Legacy LGC and Regulator Controls with new style</td>
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<td>SCM CENT Miss Dist Capital - Non-Discretionary - 2016</td>
<td>Purchase and install material and equipment in various Substations as required to service loads, upgrade equipment and replace failed facilities.</td>
<td>Replace failed equipment and facilities as encountered.</td>
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<td>SCM CENT Miss Dist Capital - Non-Discretionary - 2016</td>
<td>Substation cheats have shown many NESC compliance issues. This includes fires and numerous vertical electrical clearance issues. This project will address to</td>
<td>Replace failure and vertical electrical clearance issues. This project will address to ensure compliance (and NESC compliance)</td>
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<td>SCM CENT REPL BREAKERS - Non-Discretionary - 2016</td>
<td>Replace approximately six failed breakers per year in the Central substation area to</td>
<td>Failed units will require replacement to ensure continuity of service</td>
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<td>SCM CENT REPL BREAKERS - Non-Discretionary - 2016</td>
<td>Replace approximately twelve failed and deteriorated breakers on substations and breakers.</td>
<td>Fails units will require replacement to ensure continuity of service</td>
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<td>Discretionary</td>
<td>SCM CENT REPL BREAKERS - Non-Discretionary - 2016</td>
<td>Replace approximately twelve failed and deteriorated breakers on substations and breakers.</td>
<td>Fails units will require replacement to ensure continuity of service</td>
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<td>SCM CENT REPL BREAKERS - Non-Discretionary - 2016</td>
<td>Replace approximately twelve failed and deteriorated breakers on substations and breakers.</td>
<td>Fails units will require replacement to ensure continuity of service</td>
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<td>SCM CENT REPL BREAKERS - Non-Discretionary - 2016</td>
<td>Replace approximately twelve failed and deteriorated breakers on substations and breakers.</td>
<td>Fails units will require replacement to ensure continuity of service</td>
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<td>SCM CENT REPL BREAKERS - Non-Discretionary - 2016</td>
<td>Replace approximately twelve failed and deteriorated breakers on substations and breakers.</td>
<td>Fails units will require replacement to ensure continuity of service</td>
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<td>SCM CENT REPL BREAKERS - Non-Discretionary - 2016</td>
<td>Replace approximately twelve failed and deteriorated breakers on substations and breakers.</td>
<td>Fails units will require replacement to ensure continuity of service</td>
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<td>SCM EASTERN REDESIGN - Non-Discretionary - 2016</td>
<td>Overload issues in the Eastern area have wiring problems and need to be replaced</td>
<td>Improve public safety from catastrophic flooding, uneven ground clearance, and infrastructure. The remaining circuits that need to be moved will complete this modernization project.</td>
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<td>Overload issues in the Eastern area have wiring problems and need to be replaced</td>
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The LG&E system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's. These breakers require frequent maintenance intervals to ensure interrupting capability, require secondary oil containment, and are generally limited life expectancy. Due to our maintenance practices, we have been able to extend these units to over 40 years and are being operated at the limits of their design rating during storm and outage restoration when exposed to multiple faults. To improve reliability of these units, we need to replace defective, small capacity overhead conductor and related distribution-line equipment in rear lot applications on the LGE system. Targeted projects will generally be existing primary conductor less than #4 AWG CU with distribution line equipment in rear lot applications on the LGE system. Targeted projects will result in improving reliability by reducing the circuit's average contribution to system SAIFI.

The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's. These breakers require frequent maintenance intervals to ensure interrupting capability, require secondary oil containment, and are generally limited life expectancy. Due to our maintenance practices, we have been able to extend these units to over 40 years and are being operated at the limits of their design rating during storm and outage restoration when exposed to multiple faults. Both the KU and LGE systems include legacy oil-filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to ensure interrupting capability, require secondary oil containment, and are generally limited life expectancy. Due to our maintenance practices, we have been able to extend these units to over 40 years and are being operated at the limits of their design rating during storm and outage restoration when exposed to multiple faults.

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Louisville Gas and Electric

Gas System Planning
Ten-Year Gas Construction Plan

May 2007
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I. Crestwood-Eminence-Bedford High Pressure Distribution System

Gas System Overview
The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is fed by the Elder Park, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Elder Park City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

Maximum Allowable Operating Pressure
From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at the inlet to the Pleasureville medium pressure regulator pit (47.61 psig).

Regulator Operating Capacities
- Elder Park City Gate Station – 19.52%
- Crestwood City Gate Station – 68.54%
- Bedford City Gate Station – 61.9%

Gas System Constraints
The system is composed primarily of 4-inch pipeline, limiting the system’s capacity for expansion.
I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Connect the Ballardsville gas transmission line to the Crestwood-Bedford HP system with 5,900 feet of 8” steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22 (see Section III).

Minimum Gas System Pressure (-12°F)
- Inlet to Pleasureville – 59.36 psig

Regulator Operating Capacities
- Bedford City Gate Station – 61.13%

Recommended Timeline – 2010-2015

Reinforcement 2
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location.

If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood–Bedford line should a failure occur.

Minimum Gas System Pressure (-12°F)
- Inlet to Pleasureville – 49.01 psig

Regulator Operating Capacities
- Bedford City Gate Station – 61.8%
- Crestwood City Gate Station – 71.7%

Recommended Timeline – 2008-2009

Reinforcement 3
- Install a new city gate station near L’Esprit Farms at the intersection of E Hwy 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along E Hwy 146 to connect with the Elder Park/Ballardsville Line.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

Recommended Timeline – TBD
II. East End Gate Stations

Gas System Overview
The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure
The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints
If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the Zorn Ave regulator station (162.70 psig).

The predicted minimum gas system pressure on the Crestwood system is located at the inlet to the Pleasureville regulator pit (47.60 psig).

The predicted minimum gas system pressure on the LaGrange system is located at 4705 Hwy 146 (64.66 psig).

Regulator Operating Capacities
- Elder Park City Gate Station – 19.52%
- Crestwood City Gate Station – 73.70%
- LaGrange City Gate Station – 7.53%

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions
- Operate the Elder Park City Gate Station at 350 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig
II. East End Gate Stations (cont’d)

Reinforcement 1
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 4,770 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,900 feet of 8-inch pipeline.

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – 293.56 psig
- Pleasureville Inlet – 129.26 psig
- 4705 Hwy 146 – 64.66 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 22.09%
- Crestwood City Gate Station – 50.49%
- LaGrange City Gate Station – 7.53%

Recommended Timeline – 2010-2015

Reinforcement 2
Connect the Elder Park system to the LaGrange system

- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,300 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – 293.12 psig
- Pleasureville Inlet – 129.26 psig
- 4705 Hwy 146 – 70.71 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 23.95%
- Crestwood City Gate Station – 50.56%
- LaGrange City Gate Station – 2.77%

Recommended Timeline – 2015 – 2020
East End Gate Stations – Reinforcement 1

- Elder Park City Gate Station
- Hwy 53 Main Extension
- Hwy 393 Main Extension
- Crestwood City Gate Station
East End Gate Stations – Reinforcement 2

LaGrange City Gate Station
Elder Park City Gate Station
Hwy 393 Main Extension
Hwy 146/Fox Run Rd Main Extension
III. Harrods Creek Project

Gas System Overview
The Harrods Creek system is a segment of a large medium pressure gas system which serves a portion of the Prospect area. This area is composed primarily of residential and commercial customers. It has continued to experience growth in the residential sectors with homes ranging from 4,000 to 5,000 sq. ft, including the Harrods Glen subdivision and a proposed Wolf Pen development.

Regulator Facilities
The regulator facility that supplies gas to the Harrods Creek area is as follows:

- The regulator pit at River Rd and Wolf Pen Branch Rd (U.S. Highway 42).

Maximum Allowable Operating Pressure (MAOP)
The Harrods Creek system has a maximum allowable operating pressure of 30 psig.

Model Results

Minimum Gas System Pressure (-12 °F)
The predicted minimum gas system pressure is located on Wolf Dr (6.28 psig).

Regulator Operating Capacities
- River Rd and Wolf Pen Branch Rd (U.S. Highway 42) – 63.18%

Gas System Constraints
Gas system constraints are caused by the small diameter piping infrastructure within this area. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 1,293 ft of 6-inch medium pressure pipeline along Wolf Pen Branch Rd between Green Springs Dr and Springdale Rd.

Minimum gas system pressure (-12 °F)
- Wolf Dr – 18.98 psig
- Proposed subdivision (Fincastle Farm) – 22.68 psig
- Farm Spring Dr – 22.58 psig

Regulator Operating Capacities
- River Rd and Wolf Pen Branch Rd (U.S. Highway 42) – 63.18%

Recommended Timeline – 2010-2012
Harrods Creek Project - Reinforcement 1

River Rd and Wolf Pen Branch Rd Reg.

Reinforcement 1

Proposed Development
IV. LaGrange Medium Pressure Systems

Gas System Overview
The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section III). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure
These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

<table>
<thead>
<tr>
<th>Sub-System MAOP</th>
<th>Location</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 psig systems</td>
<td>3501 Mattingly Road</td>
<td>7.3 psig</td>
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<tr>
<td>30 psig system</td>
<td>Fallen Wood Lane</td>
<td>22.79 psig</td>
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<td>35 psig systems</td>
<td>Cedar Point Road and Hwy N 393</td>
<td>28.5 psig</td>
</tr>
<tr>
<td></td>
<td>Cherrywood Place Section 3A-1</td>
<td>-20.26 psig</td>
</tr>
</tbody>
</table>

Regulator Operating Capacities:
• Regulator pit at New Cedar Point Rd and Hwy 146 – 42.89%
• Regulator assembly at Commerce Pkwy and Button Court Ln – 4.53%
• Regulator assembly at Springhouse Estates Section 1 – 100%
• Regulator assembly at Hwy 146 and Fort Pickens Rd – 1.89%
• Regulator assembly at Hoffman Ln & Parkview Manor – 35.79%
• Regulator assembly at Crystal Dr & Grange Dr – 19.32%
• Regulator pit at Granger Rd & Hwy 53 – 19.99%
• Regulator assembly at Zhale Smith Rd & Hwy 53 – 2.45%
• Regulator assembly at Cherry Creek Rd and Hwy 53 – 100%
• Regulator pit at Glen Eagle Subdivision and Hwy 53 – 46%
• Regulator assembly at Prestwick Dr & Hwy 53 – 49.40%
• Medium pressure regulator assembly at Moody Ln & Hwy 53 – 24.30%
• Regulator assembly at Deer Run Dr – 15.50%
• Regulator pit at Elder Park Rd – 65.38%
IV.  LaGrange Medium Pressure Systems (cont’d)

30 psig systems
- Regulator pit at Woodlawn Ave and Lagrange Rd – 6.93%
- Lagrange medium pressure regulator pit – 5.0%
- Regulator pit at Hoffman Ln – 35.79%

10 psig systems
- Regulator pit at Hwy 146 – 15.90%
- Regulator pit at Hwy 393 & Hwy 146 – 1.59%
- Regulator pit at Kings Ln & Hwy 146 – 2.95%
- Regulator assembly at Park Rd & Hwy 53 – 1.97%
- Regulator assembly at E. Moody Ln & Cal Ave – 9.3%
- Regulator assembly at Georgie Way and Moody Ln – 5.72%
- Regulator assembly at Hazelwood Dr & Elder Park Rd – 20.36%
- Regulator assembly at Sycamore Rd and Elder Park Rd – 42.44%

Gas System Constraints
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

Gas System Reinforcements Planned for 2007

Gas system reinforcements scheduled for completion in 2007 include:

- Replace 1/8” orifice plates at Cherry Creek Rd and Hwy 53 regulator assembly (35 psig system) with 3/8” orifice plates.
- Extend 4” PL main in Hwy 53 from existing 6” PL at Cherry Creek Rd to 4” CT at Gleneagles Way. Retire regulator pit at Hwy 53 & Glen Eagle Subdivision.
- The OCEDA Economic Development Campus is under construction. 3,500’ of 4” PL has been extended in New Moody Ln from Baptist Hospital Northeast to the new Rawlings Group Office Campus.

Recommended Gas System Reinforcements:

Reinforcement 1
Replace 3/8” orifice plates at Springhouse Estates Section 1 regulator assembly (35 psig system) with 1/2” orifice plates.

Minimum Gas System Pressure (-12°F)
- Majestic Woods Dr – 27.69 psig

Regulator Operating Capacity
- Springhouse Estates Section 1 – 48.9%

Recommended Timeline – 2007
IV. LaGrange Medium Pressure Systems (cont’d)

Reinforcement 2
Extend gas mains and uprate LaGrange MP system as described in “An Analysis of the OCEDA Economic Development Campus” dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 MCFH. The proposed reinforcement project requires installing:

- 16,400 ft of 4 inch pipe
- 16,500 ft of 6 inch pipe
- An uprate of 10.8 miles of existing pipeline and 440 existing customers
- A new regulator facility at Moody Lane and North Fible Lane

Minimum gas system pressure (-12°F):
- Peak Road near Hwy 53 – 32.79 psig

Regulator Operating Capacities:
- Moody Ln and North Fible Ln – 11.8%
- Granger Rd and Hwy 53 – 47.6%
- Elder Park Rd – 59.3%

Recommended Timeline – 2008-2012

Reinforcement 3
Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in “An Analysis of Proposed Development at Buckner Crossings” dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90MCFH. The proposed reinforcement requires installing:

- 5,100 ft of 6-inch pipe
- 5,300 ft of 4-inch pipe
- 13,100 ft of 2-inch pipe
- Uprate 400 ft of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

Minimum Gas System Pressure (-12°F)
- Northern Patio Home Circle – 33.84 psig

Regulator Operating Capacity
- Hwy 393 & Commerce Pkwy – 26.82%
- Commerce Pkwy & Button Court Ln – 17.53%

Recommended Timeline – TBD
LaGrange Medium Pressure Gas System – Reinforcements 1
LaGrange Medium Pressure Gas System – Reinforcement 2

OCEDA Development Area

New facility at Moody Lane and North Fible

Moody Lane

HWY 53
LaGrange Medium Pressure Gas System – Reinforcement 3

- Button Court Ln
- Hwy 393 & Hwy 146
- Buckner Crossing Development Area
- New Regulator Pit at Hwy 393 & Commerce Pkwy
V. Middletown Medium Pressure System

Gas System Overview
The Middletown medium-pressure system will require reinforcement to continue to serve the Norton Commons development and the Old Brownsboro Crossing commercial park, which includes a professional medical center, office buildings, and retail/restaurants.

Gas System Reinforcement Completed in 2006
- Installed approximately 200 ft of 4-inch plastic main along Collins Lane across Chamberlain Lane.
- Installed approximately 430 ft of 4-inch plastic main near 7405 and 7314 Orchard Grass Blvd.
- Uprated 5,349 services and 72.2 miles of main from 30 psig to 50 psig. The uprate area is bordered by Hurstbourne Parkway on the west, Westport Road and LaGrange Road on the south, Crestwood on the east, and Norton Commons and existing infrastructure on the north.
- Closed the 8-inch valve at Hurstbourne Parkway and Brownsboro Road.
- Retired the Collins Lane and Electric Substation regulator pit.

Model Results

Minimum gas system pressure (-12 °F)
- 10928 Worthington Ln – 38.78 psig

Regulator Operating Capacities
- Brownsboro Rd & Worthington – 14.13%
- Westport Rd & Murphy Ln – 94.56%
VI. Old Henry Road Development

Gas System Overview
The area around Old Henry Rd is served by the Middletown medium pressure system. With the addition of the Old Henry Road Business Park and realignment of Old Henry Rd, it will be necessary to perform reinforcement work on this gas system.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator pit at English Station Way
- Regulator pit at Old Henry Rd and Terra Crossing Blvd (Old Henry MP)
- Regulator assembly at Conner Station Rd

Maximum Allowable Operating Pressure
The Middletown medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum gas system pressure (-12°F)
The predicted minimum gas system pressure is located at 1601 Keever Ct (-47.56 psig). Other low pressure locations are as follows:

<table>
<thead>
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<th>Location</th>
<th>-12°F</th>
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<td>2725 Flat Rock Rd</td>
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<td>1601 Keever Ct</td>
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<td>Whispering Pines Cir</td>
<td>-45.59</td>
<td>-23.59</td>
<td>5.78</td>
<td>15.03</td>
</tr>
</tbody>
</table>

Note: The system cannot adequately serve the Polo Fields, Persimmon Ridge, and Fox Run under current conditions.

Regulator Operating Capacities
- English Station Way – 54.73%
- Old Henry MP – 15.69%
- Conner Station & Colt Run Rd – 6.07%

Recommended Gas System Reinforcements

Reinforcement 1
Install 5,700 ft of 8-inch medium pressure pipe north along Old Henry Rd to tie into the 8-inch main at 9207 Ash Land Ct.
VI. Old Henry Road Development (cont’d)

Minimum gas system pressure (-12 °F)
- Keever Ct – 17.23 psig
- Flat Rock Rd. – 24.60 psig
- Whispering Pines Cir – 23.85 psig
- Davenport Dr – 23.64 psig

Regulator Operating Capacities
- English Station Way – 54.49%
- Old Henry MP – 31.79%
- Conner Station & Colt Run Rd – 5.37%

Recommended Timeline – 2007
VII. River Road Regulator Assemblies

Gas System Overview
Gas System Planning has identified eight regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park Line.

Gas System Reinforcement Anticipated in 2007
As part of the Farm Tap upgrade project, several medium pressure reinforcements will be made, resulting in the removal of two River Road Assemblies. The reinforcements are:

- Install 1,900 feet of 4-inch PL main in River Road from River Creek Dr up to Harrods Creek. Tie-in to regulator assembly at River Rd & Creekside Ct, uprate the River Creek Drive system from 10-35 psig and remove the River Creek Dr regulator assembly. New main will allow eventual tie-in to Harrods Creek MP system and retirement of River Creek Dr regulator assembly.
- Install 2,200 feet of 4-inch PL main in River Road from 7009 River Rd to 7314 River Rd. Tie in to systems at River Rd & Private Dr, River Rd & Transylvania and River Rd & Mayfair Rd. Retire regulator assemblies at Private Dr and Mayfair Rd.

Regulator Facilities
The regulator facilities affected by this project are as follows:

- Regulator assemblies at Riverside Dr, River’s Edge Rd, Knights of Columbus, Longview Ave, Woodside Rd, Juniper Beach Dr, and Creekside Ct
- Regulator pits at Blankenbaker Ln, Boxhill Ln, Glenview Ave, Lime Kiln Ln, Harbortown Rd, and River Creek Dr

Maximum Allowable Operating Pressure
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 250 psig.

The Longview Ave, Woodside Rd, and Creekside Dr systems have a maximum allowable operating pressure of 10 psig.

The Riverside Dr, Knights of Columbus, Boxhill Ln, and Lime Kiln Ln systems have a maximum allowable operating pressure of 20 psig.

The Blankenbaker Ln and Glenview Ave systems have a maximum allowable operating pressure of 30 psig.

The River’s Edge Rd, Juniper Beach Dr, Harbortown Rd, and River Creek Dr systems have a maximum allowable operating pressure of 35 psig.
VII. River Road Regulator Assemblies (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
- Uprate River Rd & Creekside Dr medium pressure system from 10 psig to 35 psig.
- Install approximately 1,900 ft of 4-inch plastic gas main from 6301 River Road to 6421 River Road, connecting Creekside and River Creek systems.
- Remove the River Rd & Creekside Dr regulator assembly.

Minimum Gas System Pressure (-12°F)
- 5702 Captains Quarters Rd – 34.79 psig

Regulator Operating Capacity
- River Rd & River Creek Dr – 44.71%

Recommended Timeline – 2007

Reinforcement 2
- Install approximately 2,800 ft of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 840 ft of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and Creekside Ct regulator assemblies and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure
- 5702 Captains Quarters Rd – 34.78 psig

Regulator Operating Capacity
- River Rd & River Creek Dr – 51.56%

Recommended Timeline – 2008-2012

Reinforcement 3
- Uprate River Rd & Woodside Rd medium pressure system from 10 psig to 30 psig.
- Uprate River Rd & Lime Kiln Ln medium pressure system from 20 psig to 30 psig.
- Install approximately 850 ft of 4-inch plastic gas main along Arden Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 1,200 ft of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.
- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.
VII. River Road Regulator Assemblies (cont’d)

Minimum Gas System Pressure (-12°F)
- Both ends of Blakely Ridge Rd – 16.65 psig

Regulator Operating Capacity
- River Rd & Glenview Ave – 19.52%

Recommended Timeline – 2008-2012

Reinforcement 4
- Uprate River Rd & Longview Ave medium pressure system from 10 psig to 20 psig.
- Install approximately 775 ft of 2-inch plastic gas main along Longview Ln to connect Longview Ave and Boxhill Ln systems.
- Remove the River Rd & Longview Ave regulator assembly

Minimum Gas System Pressure (-12°F)
- 4508 Longview Ln – 18.28 psig

Regulator Operating Capacity
- River Rd & Boxhill Ln – 20.66%

Recommended Timeline – 2008-2012

Reinforcement 5
- Uprate River Rd & Knights of Columbus medium pressure system from 20 psig to 35 psig.
- Install approximately 350 ft of 2-inch plastic gas main along River Rd to connect River’s Edge Rd and Knights of Columbus systems.
- Remove the River Rd & Knights of Columbus regulator assembly.

Minimum Gas System Pressure (-12°F)
- Southeast end of the former Knights of Columbus system – 34.83 psig

Regulator Operating Capacity
- River Rd & River’s Edge Rd – 13.13%

Recommended Timeline – 2008-2012
VII. River Road Regulator Assemblies (cont’d)

Reinforcement 6
- Uprate River Rd & Riverside Dr medium pressure system from 20 psig to 30 psig.
- Install approximately 250 ft of 2-inch plastic gas main along Riverside Dr to connect Riverside Dr and Blankenbaker Ln systems.
- Remove the River Rd & Riverside Dr regulator assembly.

Minimum Gas System Pressure (-12°F)
- 2630 Phoenix Hill Dr – **17.65 psig**

Regulator Operating Capacity
- Blankenbaker Ln & River Rd – **20.67%**

Recommended Timeline – 2008-2012
River Road Regulator Assemblies – Reinforcement 1 & 2

River Creek

Harbortown

Main Extensions

Creekside

Juniper Beach
VIII. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview
The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Gas System Reinforcement Completed in 2006/2007
A 6-inch medium pressure plastic main was installed along Tucker Station Road from Betty Ray Lane, south to just past Sycamore Station Place. A 4-inch medium pressure plastic main was tied-in at this point and installed along Sycamore Station Place west and south to Tucker Station Road.

Regulator Facilities
The following regulator facility feeds the Plantside Drive/Blankenbaker Parkway medium pressure system:

- Regulator pit at Watterson Trail and Plantside Drive

Maximum Allowable Operating Pressure
This medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on 3025 Element Lane (27.47 psig).

Regulator Operating Capacity
- Watterson Tr and Plantside Dr – 82.50%

Gas System Constraints
Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

Recommended Gas System Reinforcements:

Reinforcement 1
- Install a new medium pressure regulator facility on Tucker Station Road, north of I-64 that is fed from the existing 16-inch high pressure pipeline parallel to I-64.
- Install approximately 1,700 ft of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.
VIII. Plantside Drive/Blankenbaker Parkway Medium Pressure System (cont’d)

- Install approximately 2,860 ft of 6-inch medium pressure plastic pipeline west from the entrance of the proposed office park, along Tucker Station Road, to the 6-inch main ending on Plantside Drive (near the Papa John’s Building). This would allow for a multiple feed system, improving system reliability.

*Minimum gas system pressure (-12°F):*
  - 3025 Element Ln – **27.46 psig**
  - 2801 Constant Comment Place – **28.68 psig**

*Regulator Operating Capacities:*
  - Tucker Station Rd & I-64 (4x3 Mooney assembly with 35% plates) – **33.91%**
  - Watterson Tr & Plantside Dr – **82.12%**

*Recommended Timeline: 2007-2008*

*Note:* This reinforcement should be completed after the Kentucky Department of Transportation widens Tucker Station Road and Pope Lick Road.
Plantside Drive Medium Pressure Gas System – Reinforcement 1

Eastern Kentucky Line

New regulator facility

Install main on Tucker Station Road

Proposed Business Parks
IX. Jeffersontown/Fern Creek Medium Pressure System

Gas System Overview
The Jeffersontown and Fern Creek areas are part of a large medium pressure gas system that serves the southeastern part of Jefferson County. This system is composed of rural, residential, and small commercial customers and has continued to experience rapid growth in these sectors. The majority of Jeffersontown and Fern Creek areas are served from the following regulator facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator pit at Taylorsville Road and Hopewell Road (Jeffersontown Pit)
- Regulator assembly at Gentry Lane and the Calvary Line
- Regulator pit at Cedar Creek Road and the Calvary Line
- Regulator station at Hudson Lane

Maximum Allowable Operating Pressure
The Jeffersontown/Fern Creek medium pressure gas system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressures (-12 °F)
- 11708 Kewana Ct – 5.63 psig
- 5207 Pine Bunch Ct – 7.67 psig
- 7701 Windgate Dr – 5.63 psig
- 8012 Kendrick Crossing Ln – 5.26 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 15.20%
- Gentry Lane and the Calvary Line – 91.90%
- Cedar Creek Road and the Calvary Line – 10.67%
- Hudson Ln Station – 44.41%

Gas System Constraints
Gas system constraints in this area are primarily due to the infrastructure of small diameter piping coming from the sources. Due to current and anticipated growth it will be necessary to perform gas system reinforcement work.
IX. Jeffersontown/Fern Creek Medium Pressure System (cont’d)

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Jeffersontown/Fern Creek medium pressure distribution system from 35 psig to 60 psig. This uprate consists of approximately 14,123 services and 180 miles of main (107.3 miles of plastic and 70.8 miles of steel).

Minimum gas system pressure (-12°F)
- 11708 Kewana Ct – 30.98 psig
- 5207 Pine Bunch Ct – 34.76 psig
- 7701 Windgate Dr – 33.22 psig
- 8012 Kendrick Crossing Ln – 33.13 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 19.73%
- Gentry Lane and the Calvary Line – 85.53%
- Cedar Creek Road and the Calvary Line – 13.95%
- Hudson Ln Station – 68.82%

Recommended Timeline – 2008-2010

Reinforcement 2
- Loop approximately 8,370 feet of 6-inch medium pressure gas pipeline along Taylorsville Road from the outlet of the regulator facility to Saratoga Woods Drive.
- Install approximately 1,400 feet of 4-inch medium pressure plastic gas pipe east along Chenoweth Run Road from the 6-inch on Taylorsville Road.

Minimum gas system pressure (-12 °F)
- 11708 Kewana Ct – 25.07 psig
- 5207 Pine Bunch Ct – 48.82 psig
- 7701 Windgate Dr – 33.79 psig
- 8012 Kendrick Crossing Ln – 33.69 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 20.36%
- Gentry Lane and the Calvary Line – 85.24%
- Cedar Creek Road and the Calvary Line – 13.82%
- Hudson Ln Station – 68.24%

Recommended Timeline – 2008-2010
Taylorsville Road/Jeffersontown Medium Pressure Gas System – Reinforcement 2

- Looped pipe
- 4-inch pipe extension
- Jeffersontown Pit
- Taylorsville Rd
- Saratoga Woods Dr
- I-265

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Bellar
X. Bardstown Medium Pressure System

Gas System Overview
The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 2-3 years.

Gas System Reinforcements completed in 2007
Installed approximately 1,800 ft of 8-inch medium pressure pipeline along the Bardstown Bypass (Hwy 245) to connect to the existing 6-inch and 8-inch medium pressure pipe infrastructure.

Regulator Facilities
The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

Maximum Allowable Operating Pressure (MAOP)
The Bardstown medium pressure system has a maximum allowable operating pressure of 45 psig.

Model Results

Minimum Gas System Pressure (-12 °F)
The predicted minimum gas system pressure is located at **160 Deep Springs Dr** (20.14 psig).

Regulator Operating Capacities
- Bardstown MP – **15.39%**
- Chris's Creation MP – **18.89%**

Gas System Constraints
Gas system constraints are caused by the lack of a direct gas supply route from the regulator station at the LG&E Bardstown office to the downtown Bardstown area. Due to current and anticipated growth, it will be necessary to reinforce the gas system.
X. Bardstown Medium Pressure System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 1,916 ft of 4-inch plastic pipeline along Gilkey Rd and tie into the existing 8-inch steel main on Loretto Rd.

*Minimum gas system pressure (-12 °F)*
- 160 Deep Springs Dr – 20.14 psig

*Regulator Operating Capacities*
- Bardstown MP – 15.37%
- Chris's Creation MP – 19.03%

*Recommended Timeline – 2008-2012*
*Note:* This reinforcement provides an alternate feed into the system.

Reinforcement 2
Install approximately 3,177 ft of 4-inch plastic pipeline along Filiatreau Ln and tie into the existing 4-inch plastic main on Glenwood Dr.

*Minimum gas system pressure (-12 °F)*
- 160 Deep Springs Dr – 34.15 psig

*Regulator Operating Capacities*
- Bardstown MP – 14.39%
- Chris's Creation MP – 27.54%

*Recommended Timeline – 2008-2012*
*Note:* This reinforcement should be done in conjunction with the expansion of the Highway 605 industrial park.
X. **Bardstown Medium Pressure System (cont’d)**

Reinforcement 3
Install a medium pressure regulator facility off the high pressure transmission line at the intersection of North Third Street and the Bardstown Bypass (Hwy 245).

**Note:** Based on Reinforcement 1 of the Mt. Washington/Lebanon Junction High Pressure System (see Section XVIII; see also Section XXIII, Scenario 2), the new regulator facility would allow gas to feed directly into the center of the system to eliminate the low-pressure problem at Meadow Ridge Dr. The new low pressure point is located east of the Bardstown MP facility.

**Minimum gas system pressure (-12 °F)**
- 160 Deep Springs Dr – **34.74 psig**
- 116 Andrea Ct – **33.76 psig**
- 212 Meadow Ridge Dr – **43.32 psig**

**Regulator Operating Capacities**
- Bards2MP (new pit) – **11.77%**
- Bardstown MP – **5.77%**
- Chris's Creation MP – **18.96%**

**Recommended Timeline – TBD**
**Note:** Should be completed in conjunction with the Mt. Washington/Lebanon Junction high-pressure pipeline project.
Bardstown Medium Pressure Gas System – Reinforcement 1

Haverly Ct
Bardstown MP
Chris Creation MP
Reinforcement 1
Bardstown Medium Pressure Gas System – Reinforcement 2
Bardstown Medium Pressure Gas System – Reinforcement 3

- Hwy 31 E
- Mt. Washington / Lebanon Junction high-pressure pipeline
- Bards2MP (new pit)
- 44.75 psig

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XI. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and HiLand
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Hwy 44 and Boardwalk

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is scheduled to be uprated to 60 psig in 2007.
XI. Highway 44 Regulator Assemblies (cont’d)

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on Winding Woods Trail (30.36 psig).

Regulator Operating Capacities
- Mt Washington MP – 11.21%
- Hwy 44 and Woodlake – 39.19%
- Hwy 44 and Harris – 22.07%
- Hwy 44 and Fisher – 63.82%
- Hwy 44 and Highland Spring – 29.81%
- Hwy 44 and Bethel Church – 36.50%
- Hwy 44 and Azure – 6.61%
- Hwy 44 and Truman – 20.11%
- Hwy 44 and Kennedy – 4.22%
- Hwy 44 and Bogard – 62.22%
- Hwy 44 and Bells Mill – 20.54%
- Hwy 44 and Alpar – 4.02%
- Hwy 44 and Mockingbird – 39.42%
- Hwy 44 and Sunview – 28.11%
- Hwy 44 and Watergate – 1.19%
- Hwy 44 and HiLand – 4.56%
- Hwy 44 and Big Clifty – 8.06%
- Hwy 44 and Halls – 3.70%
- Hwy 44 and Boardwalk – 16.99%

Recommended Gas System Reinforcements

Reinforcement 1
- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 570 feet of 4-inch plastic main along Hwy 44.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,350 ft of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Tanager Landing Apartments off Hwy 44 – 33.86 psig
XI. Highway 44 Regulator Assemblies (cont’d)

Regulator Operating Capacities
- Hwy 44 and Halls Ln – **29.08%**

Recommended Timeline – 2008-2015

Reinforcement 2
- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,780 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

Minimum Gas System Pressure (-12°F)
- Douglass Drive – **34.98 psig**

Regulator Operating Capacities
- Hwy 44 and Hi-Land– **5.74%**

Recommended Timeline – 2008-2015

Reinforcement 3
- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.

Minimum Gas System Pressure (-12°F)
- Old Hickory Lane – **32.24 psig**

Regulator Operating Capacities
- Hwy 44 and Sunview – **68.56%**

Recommended Timeline – 2008-2015

Note: Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4
- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,200 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

Minimum Gas System Pressure (-12°F)
- Bells Mill Road and Farris Intersection – **32.15 psig**

Regulator Operating Capacities
- Hwy 44 and Bells Mill – **22.46%**

Recommended Timeline – 2008-2015
XI. Highway 44 Regulator Assemblies (cont’d)

Reinforcement 5
- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,900 feet of 6 inch plastic main along Hwy 44.
- Connect Systems served by Bethel Church and Highland Springs facilities with 1,300 feet of 4- or 6-inch plastic main along Hwy 44.
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, and Bethel Church Road facilities.

Minimum Gas System Pressure (-12°F)
- Simmons Lane – 33.37 psig

Regulator Operating Capacities
- Hwy 44 and Bogard – 67.44%
- Hwy 44 and Azure – 25.43%
- Hwy 44 and Highland Springs – 53.92%

Recommended Timeline – 2008-2015

Reinforcement 6
- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,650 feet of 6-inch plastic pipe between Harris and Woodlake.
- Convert approximately 34 high-pressure services to medium pressure.
  Note: Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

Minimum Gas System Pressure (-12°F)
- Winding Woods Trail – 30.39 psig

Regulator Operating Capacities
- Hwy 44 and Fisher – 60.20%
- Hwy 44 and Woodlake – 68.68%

Recommended Timeline – 2008-2015
Hwy 44 Regulator Assemblies – Reinforcement 2
Hwy 44 Regulator Assemblies – Reinforcement 5
XII. Hodgenville Medium Pressure System

Gas System Overview
The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

Regulator Facilities
The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

Maximum Allowable Operating Pressure
The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is located at 2017 US Highway 31E (11.87 psig).

Regulator Operating Capacity
- Highway 84 and Glendale Rd – 18.24%

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Hodgenville medium pressure gas distribution system to 50 psig. This uprate will affect approximately 1,241 services and 25.3 miles of pipeline.

Minimum Gas System Pressure (-12°F)
- 2017 US Highway 31E – 46.05 psig

Regulator Operating Capacity
- Highway 84 and Glendale Rd – 18.29%

Recommended Timeline – 2009-2015
XIII. Waste Management Relocation Project

Gas System Overview
The Penile City Gate Station supplies gas to the Preston City Gate Station via a 20-inch transmission pipeline (the Penile to Preston Line). The Penile to Preston Line crosses Waste Management landfill property from the Outer Loop to I-65. The two primary feeds associated with this pipeline are from the Penile and Preston City Gate Stations. Due to planned construction at the landfill, approximately 6,000 ft of the Penile to Preston Line that run through the landfill property must be relocated.

Maximum Allowable Operating Pressure
The Penile to Preston Line has a maximum allowable operating pressure of 420 psig.

Recommended Relocation
Shift the portion of the pipeline that runs through landfill property approximately 500 ft to the southeast. The pipeline should roughly run along an access road in the landfill and should reconnect with the existing pipeline before it crosses underneath I-65. This relocation will require approximately 6,600 ft of 20-inch high-pressure pipeline.

Recommended Timeline – TBD
Waste Management Relocation Project – Recommended Relocation

Portion to be relocated
XIV. Minor Lane Heights Renaissance Zone

Gas System Overview
The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure
The Minor Lane Heights system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at 2240 Outer Loop (26.03 psig). There is another low pressure point at the south end of Eagle Pass (26.84 psig).

Regulator Operating Capacities
- Preston City Gate Station MP – 54.13%
- Outer Loop and Grade Ln – 26.52%

Gas System Constraints
Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.
**XIV. Minor Lane Heights Renaissance Zone (cont’d)**

**Recommended Gas System Reinforcements**

**Reinforcement 1**
- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 ft of 8-inch plastic main along Outer Loop, Stinnett Ln, proposed two-lane “A,” and proposed boulevard “A” to serve UPS facility.

*Minimum Gas System Pressure (-12°F)*
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) – 27.37 psig
- New UPS Facility – 34.36 psig

*Regulator Utilization*
- Preston City Gate Station MP – 53.57%
- Outer Loop and Grade Ln – 28.07%

*Recommended Timeline – 2007*

**Reinforcement 2**
Install and remove gas mains according to “An Analysis of the Minors Lane Heights Renaissance Zone” dated 15 January 2007 or the latest version.

- Retire existing pipelines in the area.
- Install approximately 1,200 ft of 2-inch pipe
- Install approximately 15,400 ft of 4-inch pipe
- Install approximately 9,900 ft of 8-inch pipe

*Minimum Gas System Pressure (-12°F)*
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) – 26.07 psig

*Regulator Operating Capacities*
- Preston City Gate Station MP – 54.33%
- Outer Loop and Grade Ln – 47.22%

*Recommended Timeline – 2007-2017*
Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 2
Minor Lane Heights Renaissance Zone – Reinforcement 1

Outer Loop and Grade Ln Reg.

New 8-inch plastic main
XV.  Mount Washington Medium Pressure System

Gas System Overview
The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

Gas System Reinforcement to Be Completed Summer 2007
The Mount Washington medium pressure distribution system will be uprated from 35 psig to 60 psig. This uprate consists of 61.5 miles of main (14.5 miles of steel and 46.9 miles of plastic) and 2,855 customer services.

Regulator Facilities
The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:

- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

Maximum Allowable Operating Pressure (MAOP)
The Mount Washington medium pressure gas system will have a maximum allowable operating pressure of 60 psig after completion of the uprate.

Model Results

Minimum Gas System Pressure (-12 ⁰F):
The predicted minimum pressure is located on Pin Oak Drive (40.87 psig).

Regulator Operating Capacities (-12 ⁰F):
- Mt. Washington MP – 11.24%
- Bardstown Rd and Landis Ln – 52.85%

Gas System Constraints
Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 4,300 ft of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

Minimum Gas System Pressure (-12 ⁰F)
- Pin Oak Dr – 50.28 psig
XV. Mount Washington Medium Pressure System (cont’d)

Regulator Operating Capacities (-12 °F):
- Mt. Washington MP – 10.28%
- Bardstown Rd and Landis Ln – 50.94%
- Vista Hills Blvd and Calvary Line – 100%

Recommended Timeline – 2007-2008
XVI. Preston High Pressure Distribution Pipeline Reinforcement

Gas System Overview
The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure
The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this high pressure system is located at the inlet to the **Preston and Antle regulator pit (62.38 psig)**

Regulator Operating Capacities
• Preston City Gate Station – 95.29%

Gas System Constraints
Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
The State Highway Department plans on completing a corridor alignment along Cooper Chapel Road, in the City of Okolona.

• Install approximately 31,850 ft of 12-inch high pressure gas pipeline from the Calvary line to the Preston high pressure line.
• Install a new regulator facility (4x3 Mooney assemblies with 100% plates) at Preston Highway and Cooper Chapel Road to reduce the pressure from the Calvary Line to 110 psig.

Minimum Gas System Pressure (-12°F)
• Preston and Antle inlet – 95.96 psig

Regulator Operating Capacities
• New facility at Cooper Chapel and Preston Highway – 32.5%
XVI. Preston High Pressure Distribution Pipeline Reinforcement (cont’d)

Eventually, the pipeline would be extended further south along Preston Highway and this would allow a second feed for the high pressure system (see Section XIX). Without the second feed, if the Preston high pressure pipeline was damaged, the areas of Okolona and Maryville and a portion of Shepherdsville would be lost.

Recommended Timeline – TBD

Reinforcement 2
- Extend the 8-inch steel high-pressure main south along Preston Highway from Mud Lane to Bells Mill Road (approx. 19,000 feet).
- Install a medium pressure regulator facility at Bells Mill Road and Preston Highway (4x3 Mooney with 100% plates) to be tied into the 8-inch medium pressure main on Preston Highway or Bells Mill Road.

Minimum Gas System Pressure (-12°F)
- Inlet to new Facility at Preston & Bells Mill – 70.78 psig

Regulator Operating Capacities
- Cooper Chapel and Preston – 36%
- Preston and Antle – 58%
- Preston and Bells Mill – 100%

Note: The current pressure on the Preston HP line prohibits a significant pressure differential across the new regulator assembly. The results shown are after Reinforcement 1 has been completed and assuming Shepherdsville/Northern Bullitt MP system has been uprated. Operating the Preston HP line at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the new assembly.

Recommended Timeline – TBD; after completion of Reinforcement 1
XVII. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 °F).
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 °F) with the proposed gas loads for 2005 and the Mount Washington high pressure system operating at 275 psig.
- Approximately 60-65 MCFH of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 56 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.
- LG&E can meet gas load projections until 2016 with a 2% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2016.
- LG&E can meet gas load projections until 2012 with a 4% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2012.
XVII. Mt. Washington/Lebanon Junction High Pressure Distribution System (cont’d)

- LG&E can meet gas load projections until 2011 with a 5% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2011.

**Recommended Gas System Reinforcements**

**Reinforcement 1**

Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

*Recommended Timeline – 2012-2016*

**Note:** For further information regarding proposed reinforcements to this system, see Section XXII.
Mt. Washington High Pressure Distribution System – Reinforcement 1

- Jim Beam Clermont
- New regulator facility
- 8-inch high pressure extension
- Publishers Printing
- Jim Beam Boston
- Bardstown
XVIII. Shepherdsville/Northern Bullitt County Medium Pressure System

Gas System Overview
The Shepherdsville/Northern Bullitt medium pressure gas system serves residential and commercial customers in the City of Shepherdsville and outlying areas between I-265 and Hwy 44.

Gas System Reinforcement Completed In 2006
Separated the Shepherdsville/Northern Bullitt system from the Jefferson County system, and uprated the Shepherdsville medium pressure gas distribution system to 60 psig.

Regulator Facilities
The regulator facilities that supply gas to the Shepherdsville/Northern Bullitt medium pressure system are as follows:

- Regulator pit at Lee's Lane and Highway 44
- Regulator pit at Cedar Grove Road and I-65
- Regulator pit at Mud Lane and Antle Drive
- Regulator pit at Old Bardstown Road and Thixton Lane
- Regulator pit at Vista Hills Blvd and Calvary Line

Maximum Allowable Operating Pressure
The Shepherdsville/Northern Bullitt medium pressure gas system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 ⁰F)
The predicted minimum gas system pressure for this medium pressure system is located at Arbor Creek Drive (14.57 psig)

Regulator Operating Capacities
- Hwy 44 and Lee’s Ln – 59.50%
- Cedar Grove Rd and I-65 – 27.53%
- Mud Ln and Antle Dr – 100%
- Old Bardstown Rd and Thixton Ln – 11.23%
- Vista Hills Blvd and Calvary Line – 75.74%

Gas System Constraints
Gas system constraints in this area are due to an infrastructure of small diameter pipe in the Thixton Lane and Cedar Creek Road areas in the northeastern portion of this system. There is also a severe lack of redundancy in this area which is adding to the pressure problems. Making the system more redundant in this area would prevent outages due to third-party damage or other causes.

A public works project is planned to widen (and reroute) a portion of Preston Hwy between Shepherds Way and Hebron Ln.
XVIII. Shepherdsville/Northern Bullitt County Medium Pressure System (cont’d)

Recommended Gas System Reinforcements:

Reinforcement 1
Install approximately 4,200 feet of 6-inch plastic main on Thixton Lane from Taylor Rae Drive south to the existing 6-inch plastic main located near 8506 Thixton Lane.

Minimum gas system pressure (-12 °F)
- Arbor Creek Dr – 29.66 psig

Regulator Operating Capacities
- Hwy 44 and Lee’s Ln – 56.51%
- Cedar Grove Rd and I-65 – 26.55%
- Mud Ln and Antle Dr – 100%
- Old Bardstown Rd and Thixton Ln – 12.10%
- Vista Hills Blvd and Calvary Line – 76.81%

Recommended Timeline – 2009-2012

Reinforcement 2
- Extend 1,700 feet of 6-inch plastic main from John D. Harper Blvd to Cobblestone Way to serve customers and the subdivision disconnected from the 8-inch main on Preston Hwy.
- Extend 1,500 feet 4-inch plastic main from John D Harper Blvd south to Hebron Lane.
- Extend 500 feet of 6-inch main from Lodie Lane, across Preston Hwy, and reconnect to the Cobblestone Way 6-inch main

Minimum gas system pressure (-12 °F)
- John D Harper Blvd/ Enterprise Dr – 37.97 psig
- Cambridge Ct – 38.40 psig

Recommended Timeline – Concurrent with the highway work along Preston Highway.
Shepherdsville/N. Bullitt Medium Pressure System – Reinforcement 2

- Cambridge Court
- W. Hebron Lane
- John D Harper Blvd
- Cobblestone Way
- Lodie Lane

6-inch Main Relocation

4-inch Main

6-inch Main

W. Hebron Lane
XIX. Brandenburg High Pressure System

Gas System Overview
The Brandenburg high-pressure distribution system serves the cities of Brandenburg and Doe Valley, and the surrounding area. Gas is supplied from Doe Run storage field lines at Riggs Junction. The Brandenburg area continues to experience residential and commercial growth.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is at the inlet of the regulator pit serving the Brandenburg medium-pressure system located at Old US 60 and Highway 933 (100.36 psig).
XX. Radcliff/Fort Knox Medium Pressure System

Gas System Overview
The Radcliff/Fort Knox medium pressure system serves approximately 4,800 residential and small commercial services. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/Fort Knox area over the next 8 years.

Gas System Reinforcement Anticipated in 2007
A new asphalt plant has requested gas at the site of the old Certified Construction Company at 1991 Illinois Avenue. The total connected load for the customer will be 75,000 cfh. The proposed reinforcement option will run 6-inch medium pressure main from the Radcliff #1 pit to the existing main on Northern Rd.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W. Vine Street.

Maximum Allowable Operating Pressure
The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at 151 E Lincoln Trail Blvd (28.47 psig). Another low pressure point is at the end of Hood Ln in the Yarwood Mobile Home Park (28.68 psig)

Regulator Operating Capacity (includes asphalt plant load):
- Radcliff #1: 19.61% (35.65%)
- Radcliff #2: 69.18% (71.37%)

Gas System Constraints
The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off St. Andrews Dr will require significant reinforcement.
XX. Radcliff/Fort Knox Medium Pressure System (cont’d)

Recommended Gas System Reinforcement

Reinforcement 1
- Replace existing regulators in Radcliff #2 with 4x3 Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 60 psig. This uprate consists of approximately 4,600 service laterals and approximately 3,600 customers. There is a total of 78.5 miles of pipeline of which 9.1 miles is plastic and 69.4 miles is protected steel.

Note: Additional BRAC load was estimated to be 240 MCFH based on anticipated number of new residences and current load.

Minimum gas system pressure (-12°F)
Hood Ln in the Yarwood Mobile Home Park (46.1 psig)

Regulator Operating Capacities
- Radcliff #1 – 55.91%
- Radcliff #2 – 18.62%

Recommended Timeline – 2008-2012

Reinforcement 2
- Install 4,800’ of 4-inch PL main in Otter Creek Rd from existing 4-inch CT to 2-inch PL in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.

Recommended Timeline – TBD
Radcliff/Fort Knox – Reinforcement 1 & 2

Uprate area

Radcliff #1

Radcliff #2

St. Andrews Dr

Reinforcement #2
XXI. Persimmon Ridge/Polo Fields Medium Pressure System

Gas System Overview
The 50 psig medium pressure system near Persimmon Ridge and the Polo Fields has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System. There are a few options available that will provide adequate pressures throughout the system.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator pit at English Station Way
- Regulator pit at Old Henry Rd and Terra Crossing Blvd (Old Henry MP)
- Regulator assembly at Conner Station Rd

Maximum Allowable Operating Pressure
The Persimmon Ridge/Polo Fields medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum Gas System Pressures (-12°F)
- 121 Persimmon Ridge Drive – -45.11 psig
- 17009 Bowline View Trail – -46.65 psig
- 1601 Keever Court – -47.70 psig

Note: The system cannot adequately serve the Polo Fields, Persimmon Ridge, and Fox Run under current conditions.

Regulator Operating Capacities
- English Station Way – 54.73%
- Old Henry MP – 15.69%
- Conner Station & Colt Run Rd – 6.07%

Recommended Gas System Reinforcements

Reinforcement Option 1
Loop approximately 7,150 feet of existing 4-inch medium pressure steel and plastic main with 6-inch plastic main along State Hwy 362 (Ash Avenue) from LaGrange Road, southeast to the existing 6-inch plastic main near Ashbrooke Drive.

Minimum gas system pressure (-12°F)
- 121 Persimmon Ridge Drive – -25.17 psig
- 17009 Bowline View Trail – -28.68 psig
- 1601 Keever Court – -32.41 psig
XXI. Persimmon Ridge/Polo Fields Medium Pressure System (cont’d)

Reinforcement Option 1a
This reinforcement would be the same as Option 1, but instead of using 6-inch plastic main for the loop, 8-inch plastic main would be used.

Minimum gas system pressure (-12 °F)
- 121 Persimmon Ridge Drive – -19.69 psig
- 17009 Bowline View Trail – -25.53 psig
- 1601 Keever Court – -30.25 psig

Reinforcement Option 2
Loop approximately 3,050 feet of 4-inch medium pressure steel main with 8-inch plastic main along LaGrange Road from the existing 8-inch steel main near Altawood Court, northeast to State Hwy 362 (Ash Avenue).

Minimum gas system pressure (-12 °F)
- 121 Persimmon Ridge Drive – -34.84 psig
- 17009 Bowline View Trail – -37.23 psig
- 1601 Keever Court – -39.25 psig

Reinforcement Option 3
This option would combine the main replacements from Option 1/1a and Option 2. For this option we would need to install 3,050 feet of 8-inch plastic main and 7,150 feet of 6-inch or 8-inch plastic main for a total of 10,200 feet of plastic main.

Minimum gas system pressure with Option 1 & 2 (-12 °F)
- 121 Persimmon Ridge Drive – 8.50 psig
- 17009 Bowline View Trail – 5.29 psig
- 1601 Keever Court – 0.48 psig

Minimum gas system pressure with Option 1a & 2 (-12 °F)
- 121 Persimmon Ridge Drive – 11.05 psig
- 17009 Bowline View Trail – 7.95 psig
- 1601 Keever Court – 3.54 psig

Reinforcement Option 4
This option would require the installation of approximately 5,300 feet of 6-inch medium pressure plastic main along Flat Rock Road between Robin Lane and Curry Branch Road.

Minimum gas system pressure with Option 1 & 2 (-12 °F)
- 121 Persimmon Ridge Drive – -38.79 psig
- 17009 Bowline View Trail – -40.07 psig
- 1601 Keever Court – -44.13 psig
XXI. Persimmon Ridge/Polo Fields Medium Pressure System (cont’d)

Reinforcement Option 5
See Section VI Old Henry Road Development for more information regarding this reinforcement.

*Minimum gas system pressure (-12 °F)*
- 121 Persimmon Ridge Drive – 23.97 psig
- 17009 Bowline View Trail – 20.73 psig
- 1601 Keever Court – 17.23 psig

Reinforcement Option 6
This option would require looping approximately 6,300 feet of 4-inch medium pressure steel main with 8-inch plastic main along Shelbyville Road beginning at the existing 8-inch steel main near Waterstone Way, east to Flat Rock Road.

*Minimum gas system pressure (-12 °F)*
- 121 Persimmon Ridge Drive – -2.98 psig
- 17009 Bowline View Trail – 0.98 psig
- 1601 Keever Court – -1.35 psig

Reinforcement Option 7
This reinforcement project combines Option 4 and Option 6. The main needed for this project would be 6,300 feet of 8-inch plastic and 5,300 feet of 6-inch plastic for a total of 11,600 feet of plastic main.

*Minimum gas system pressure (-12 °F)*
- 121 Persimmon Ridge Drive – 15.73 psig
- 17009 Bowline View Trail – 16.86 psig
- 1601 Keever Court – 13.96 psig

Reinforcement Option 8
This reinforcement project combines Options 1a, 2, 4, and 6. The main needed for this project would be 16,500 feet of 8-inch plastic main and 5,300 feet of 6-inch plastic main for a total of 21,800 feet of plastic main.

*Minimum gas system pressure (-12 °F)*
- 121 Persimmon Ridge Drive – 25.72 psig
- 17009 Bowline View Trail – 25.97 psig
- 1601 Keever Court – 23.41 psig
XXI. Persimmon Ridge/Polo Fields Medium Pressure System (cont’d)

Reinforcement Option 9
This is the same reinforcement work as Option 8 with the addition of the Old Henry Road extension (Option 5). This project would require approximately 23,300 feet of 8-inch plastic and 5,300 feet of 6-inch plastic main for a total of 28,600 feet of plastic main.

Minimum gas system pressure (-12 °F)
- 121 Persimmon Ridge Drive – 32.72 psig
- 17009 Bowline View Trail – 31.98 psig
- 1601 Keever Court – 29.52 psig

Reinforcement Option 10
This option requires installing approximately 13,400 of 6-inch plastic main on Todds Point Road from the existing 4-inch plastic main near Chapel Drive, southeast to the existing 6-inch plastic main on Aiken Road. Also, an additional 3,400 feet of 6-inch plastic main would need to be installed on State Hwy 1818 from Todds Point Road, northeast to Abbott Lane to connect with a small existing 35 psig system. This existing system would have to be uprated from 35 psig to 50 psig, and the orifice plates at the Abbotts Ln & Myers Ln regulator assembly would need to be changed to 1/2”. This option would require installing a total of 16,800 feet of 6-inch plastic main and would require uprating the system consisting 116 services from 35 psig to 50 psig. While this option may not be currently feasible, it would provide another feed into this area and allow for additional growth.

Minimum gas system pressure (-12 °F)
- 121 Persimmon Ridge Drive – 30.88 psig
- 17009 Bowline View Trail – 25.56 psig
- 1601 Keever Court – 21.25 psig
Persimmon Ridge/Polo Fields Reinforcement Options 1-10

- Option 3: Combines Option 1/1a and Option 2
- Option 7: Combines Option 4 and Option 6
- Option 8: Combines Option 1a, 2, 4, and 6
- Option 9: Combines Option 1a, 2, 4, 5, and 6
XXII. Appendix – Mt. Washington High Pressure Distribution System

Options Considered
An attempt was made to parallel the existing 8-inch and 6-inch piping in order to solve the pressure and capacity problems. Almost the entire route (approximately 21 miles) of the system would have to be paralleled in order to correct the pressure and capacity problems.

Scenario 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Preston Highway regulator station to the Shepherdsville regulator pit at Lee Lane and Highway 44 (approximately 12.5 miles). In addition, the existing 6-inch piping (approximately 12 miles) would have to be paralleled in order to alleviate the restriction to moving the gas to the south end of the system.

Scenario 2
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Scenario 3
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.
XXI. Appendix – Mt. Washington High Pressure Distribution System (cont’d)

Scenario 4
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line to the south end of the system. This would require installing approximately 16 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

Scenario 5
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line along Hwy 509 and Hwy 245 into Lebanon Junction. This would require installing approximately 12.5 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.
Mt. Washington High Pressure Distribution System – Overview
Mt. Washington High Pressure Distribution System – Mt. Washington Overview

- Mt. Washington
- LG&E Mt. Washington High Pressure Gas Facility
- Shepherdsville
- Highway 44
- Pine Creek Forest
- LG&E 8-inch High Pressure Pipeline on Highway 61
- Jim Beam Clermont Plant
- Lebanon Junction
- LG&E 6-inch High Pressure Pipeline on Highway 61
- Publishers Printing
- Jim Beam Boston Plant
- Bardstown
- LG&E Calvary Gas Transmission Pipeline
Mt. Washington High Pressure Distribution System – Scenario 1

Preston Hwy Station
Lees Ln & Hwy 44
Preston Hwy 12.5 mile extension

Fairdale
Mt. Dana
Maryville
Lees Ln & Hwy 44
Shepherdsville

Mt Washington
Mt. Washington High Pressure Distribution System – Scenario 2

- Location of new LG&E regulator facility
- 8-inch high pressure extension 14.0 miles along Hwy 245
- Jim Beam Clermont Plant
- Lebanon Junction
- Publishers Printing
- Jim Beam Boston Plant
- LG&E Calvary Gas Transmission Pipeline
Mt. Washington High Pressure Distribution System – Scenario 4

Jim Beam
Clermont
Hwy 245/Cross Country
New Regulator Facility
Bardstown
Jim Beam
Boston
Mt. Washington
Maryville
Shepherdsville
West Point
Muldraugh
Radcliff
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I. Crestwood-Eminence-Bedford High Pressure Distribution System

Gas System Overview
The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is fed by the Elder Park, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Elder Park City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

Maximum Allowable Operating Pressure
From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is at 4021 Hwy 146 (70.4 psig).

Regulator Operating Capacities
- Elder Park City Gate Station – 21.6%
- Crestwood City Gate Station – 67.8%
- Bedford City Gate Station – 73.1%

Gas System Constraints
The system is composed primarily of 4-inch pipeline, limiting the system’s capacity for expansion.
I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Connect the Ballardsville gas transmission line to the Crestwood-Bedford HP system with 5,900 feet of 8” steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22. **NOTE:** Reinforcement done as part of Section II Reinforcement 2.

*Minimum Gas System Pressure (-12°F)*
- 4021 Hwy 146 – 171.1 psig

*Regulator Operating Capacities*
- Bedford City Gate Station – 57.9%

*Recommended Timeline – 2009-2012*

Reinforcement 2
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location.

If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood–Bedford line should a failure occur.

*Minimum Gas System Pressure (-12°F)*
- Inlet to Pleasureville – 68.7 psig

*Regulator Operating Capacities*
- Bedford City Gate Station – 73.4%
- Crestwood City Gate Station – 57.8%

*Recommended Timeline – 2009-2010*

Reinforcement 3
- Install a new city gate station near L’Esprit Farms at the intersection of E Hwy 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along E Hwy 146 to connect with the Elder Park/Ballardsville Line.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

*Recommended Timeline – 2018*
Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 1

Moody Lane

HWY 53

HWY 22

8” Main Extension
II. East End Gate Stations

Gas System Overview
The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure
The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints
If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the Zorn Ave regulator station (190.9 psig).

The predicted minimum gas system pressure on the Crestwood system is located at 4021 Hwy 146 (70.35 psig).

The predicted minimum gas system pressure on the LaGrange system is located at 20 Quality Place (69.0 psig).

Regulator Operating Capacities
- Elder Park City Gate Station – 21.6%
- Crestwood City Gate Station – 67.8%
- LaGrange City Gate Station – 33.9%

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions
- Operate the Elder Park City Gate Station at 350 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig
II. East End Gate Stations (cont’d)

Reinforcement 1
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 4,770 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,900 feet of 8-inch pipeline.

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – 256.7 psig
- 4021 Hwy 146 – 171.1 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 24.7%
- Crestwood City Gate Station – 35.2%
- LaGrange City Gate Station – 34.5%

Recommended Timeline – 2009-2012

Reinforcement 2
Connect the Elder Park system to the LaGrange system

- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,300 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – 233.7 psig
- Pleasureville Inlet – 77.8 psig
- 4705 Hwy 146 – 37.0 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 26.4%
- Crestwood City Gate Station – 59.9%
- LaGrange City Gate Station – 16.9%

Recommended Timeline – 2009 – 2012
East End Gate Stations – Reinforcement 2

LaGrange City Gate Station
Elder Park City Gate Station
Hwy 393 Main Extension
Hwy 146/Fox Run Rd Main Extension
III. East End 30 psig System

Gas System Overview
The East End 30 psig system is a segment of a large medium pressure gas system which serves a portion of the Prospect area. This area is composed primarily of residential and commercial customers. It has continued to experience growth in the residential sectors with homes ranging from 4,000 to 5,000 sq. ft, including the Harrods Glen subdivision and a proposed Wolf Pen development.

Regulator Facilities
The regulator facilities that supplies gas to the Harrods Creek area is as follows:

- The regulator pit at River Rd and Wolf Pen Branch Rd (U.S. Highway 42).

Maximum Allowable Operating Pressure (MAOP)
The Harrods Creek system has a maximum allowable operating pressure of 30 psig.

Model Results

Minimum Gas System Pressure (-12 °F)
The predicted minimum gas system pressure is located on Wolfpen Ridge Ct (-1.5 psig).

Regulator Operating Capacities
- BLANKENBAKER LN. & RIVER RD. (G-335) – 17.0%
- HUBBARDS LN. & WESTPORT RD. (G-174) – 70.5%
- BROWNS LN. & ALTON RD. (G13149) – 69.0%
- SHERBURN LN.& EASTERN KY. LINE (G-426) – 23.0%
- SHELBYVILLE RD. EAST OF BRAMPTON (G-319) – 100.0%
- GLENVIEW AVE. & RIVER RD. (G-329) – 15.3%
- RIVER RD. & WOLF PEN BRANCH RD. (G-330) – 48.5%
- US 60 AND URTON LN (G397) – 50.7%
- DORSEY LN. & WARD AVE. (G-513) – 42.6%
- LAGRANGE RD. & ENGLISH STATION R (G-398) – 9.5%
- HURSTBOURNE LN. & I-64 (G-439) – 72.2%
- WEST RD. & FREYS HILL RD. (G-492) – 71.0%
- WHIPPS MILL RD. & HOUNZ LN. (G-298) – 74.5%
- SHELBYVILLE RD. & MOSER RD. (G-261) – 71.9%

Gas System Constraints
Gas system constraints are caused by the small diameter piping infrastructure within this area. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.
III. East End 30 psig System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Close valve 375163 at Springdale Dr and Barbour Ln. This is a temporary fix for the winter of 2008. This isolates a small subsystem that is fed only by the River Rd & Wolf Pen Branch Rd facility. This needs to be followed in 2009 by Reinforcement 2

Minimum gas system pressure (-12 °F)
- Wolfpen Ridge Ct (10.6 psig).

Regulator Operating Capacities
- River Rd and Wolf Pen Branch Rd (U.S. Highway 42) – 15.37%

Recommended Timeline – 2008

Reinforcement 2

Uprate the East End 30 psig system to 50 psig and open valve 375163. This uprate will allow for future tie-in to the Persimmon Ridge/Polo Fields medium pressure system to the north.

Minimum gas system pressure (-12 °F)
- Wolfpen Ridge Ctt (33.2 psig).

Regulator Operating Capacities
- BLANKENBAKER LN. & RIVER RD. (G-335) –13.3%
- HUBBARDS LN. & WESTPORT RD. (G-174) – 98.9%
- BROWNS LN. & ALTON RD. (G13149) – 80.8%
- SHERBURN LN. & EASTERN KY. LINE (G-426) – 27.5%
- SHELBYVILLE RD. EAST OF BRAMPTON (G-319) –100%
- GLENVIEW AVE. & RIVER RD. (G-329) – 12.2%
- RIVER RD. & WOLF PEN BRANCH RD. (G-330) – 39.1%
- US 60 AND URTON LN (G397) – 52.4%
- DORSEY LN. & WARD AVE. (G-513) – 46.2%
- LAGRANGE RD. & ENGLISH STATION R (G-398) – 9.9%
- HURSTBOURNE LN. & I-64 (G-439) – 77.7%
- WEST RD. & FREYS HILL RD. (G-492) – 77.0%
- WHIPPS MILL RD. & HOUNZ LN. (G-298) – 85.7%
- SHELBYVILLE RD. & MOSER RD. (G-261) – 79.1%

Recommended Timeline – 2009
East End 30 psig - Reinforcements 1 & 2

Reinforcement 2 - Uprate Area

Reinforcement 1 – Valve 375163
IV. LaGrange Medium Pressure Systems

Gas System Overview
The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure
These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

<table>
<thead>
<tr>
<th>Sub-System MAOP</th>
<th>Location</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 psig systems</td>
<td>3500 Mattingly Rd [6447519]</td>
<td>6.7 psig</td>
</tr>
<tr>
<td>30 psig system</td>
<td>300 blk Crystal Wash Dr[6487436]</td>
<td>21.9 psig</td>
</tr>
<tr>
<td>35 psig systems</td>
<td>Kamer Ct [6430958]</td>
<td>28.4 psig</td>
</tr>
</tbody>
</table>

Regulator Operating Capacities:

35 psig Systems
- HOFFMAN LN & PARKVIEW MANOR TBD – 4.8%
- BUTTON CT & COMMERCE PKWY G-21254 – 15.5%
- ALLEN LN & ARTISAN PKWY TBD – 6.9%
- HWY 53 & CHERRY CREEK DR TBD – 37.2%
- NEW CEDAR POINT RD. & OLD LAGRAN G-364 – 42.5%
- ELDER PARK RD. G-433 – 34.7%
- MOODY LN & HWY 53 G-559 – 24.0%
- E.MOODY LN.& CAL AVE G-593 – 7.3%
- DEER RUN DR G-553 – 15.1%
- GRANGER RD. & HWY.53 G-545 – 21.1%
- PARK RD. & HWY. 53 G-558 – 14.2%
- ZHALE SMITH RD & HWY 53 G-591 – 7.0%
- SPRINGHOUSE ESTATES SECTION 1 G-599 – 42.5%
- HWY 146 & FORT PICKENS RD G13112 – 0.0%
- PRESTWICK DR. & HWY. 53 G13115 – 37.9%
- CRYSTAL DR.& GRANGE DR. G18329 – 22.9%
IV. LaGrange Medium Pressure Systems (cont’d)

30 psig systems
- Regulator pit at Woodlawn Ave and Lagrange Rd – 11.5%
- Lagrange medium pressure regulator pit – 51.1%
- Regulator pit at Hoffman Ln – 39.6%

10 psig systems
- Regulator pit at Hwy 146 – 17.6%
- Regulator pit at Hwy 393 & Hwy 146 – 1.1%
- Regulator pit at Kings Ln & Hwy 146 – 1.3%
- Regulator assembly at Georgie Way and Moody Ln – 4.1%
- Regulator assembly at Hazelwood Dr & Elder Park Rd – 15.9%
- Regulator assembly at Sycamore Rd and Elder Park Rd – 28.2%

Gas System Constraints
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

Gas System Reinforcements Completed in 2007

Gas system reinforcements completed in 2007 include:
- Replace 1/8” orifice plates at Cherry Creek Rd and Hwy 53 regulator assembly (35 psig system) with ¼” orifice plates.
- Extend 4” PL main in Hwy 53 from existing 6” PL at Cherry Creek Rd to 4” CT at Glen Eagles Way. Retire regulator pit at Hwy 53 & Glen Eagle Subdivision.
- The OCEDA Economic Development Campus is under construction. 3,500’ of 4” PL has been extended in New Moody Ln from Baptist Hospital Northeast to the new Rawlings Group Office Campus.

Recommended Gas System Reinforcements:

Reinforcement 1
Extend gas mains and uprate LaGrange MP system as described in “An Analysis of the OCEDA Economic Development Campus” dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 MCFH. The proposed reinforcement project requires installing:
- 16,400 ft of 4 inch pipe
- 16,500 ft of 6 inch pipe
- An uprate of 10.8 miles of existing pipeline and 440 existing customers
- A new regulator facility at Moody Lane and North Fible Lane
IV. LaGrange Medium Pressure Systems (cont’d)

Minimum gas system pressure (-12°F):
- 2300 Stonybrook Ct – **49.6 psig**

Regulator Operating Capacities:
- Moody Ln and North Fible Ln – **1%**
- Granger Rd and Hwy 53 – **18.2%**
- Elder Park Rd – **17.4%**

Recommended Timeline – 2009-2011

Reinforcement 2
Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in “An Analysis of Proposed Development at Buckner Crossings” dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90MCFH. The proposed reinforcement requires installing:

- 5,100 ft of 6-inch pipe
- 5,300 ft of 4-inch pipe
- 13,100 ft of 2-inch pipe
- Uprate 400 ft of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

Minimum Gas System Pressure (-12°F)
- Northern Patio Home Circle – **30.6 psig**

Regulator Operating Capacity
- Hwy 393 & Commerce Pkwy – **4.2%**
- Commerce Pkwy & Button Court Ln – **11.4%**
LaGrange Medium Pressure Gas System – Reinforcement 1

OCEDA Development Area

New facility at Moody Lane and North Fible

Moody Lane

HWY 53
V. River Road Regulator Assemblies

Gas System Overview
Gas System Planning has identified eight regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park Line.

Gas System Reinforcement Completed in 2007
As part of the Farm Tap upgrade project, several medium pressure reinforcements will be made, resulting in the removal of two River Road Assemblies. The reinforcements are:

- Installed 1,900 feet of 4-inch PL main in River Road from River Creek Dr up to Harrods Creek. Tie-in to regulator assembly at River Rd & Creekside Ct, uprate the River Creek Drive system from 10-35 psig and remove the River Creek Dr regulator assembly. New main will allow eventual tie-in to Harrods Creek MP system and retirement of River Creek Dr regulator assembly.
- Installed 2,200 feet of 4-inch PL main in River Road from 7009 River Rd to 7314 River Rd. Tie in to systems at River Rd & Private Dr, River Rd & Transylvania and River Rd & Mayfair Rd. Retire regulator assemblies at Private Dr and Mayfair Rd.

Regulator Facilities
The regulator facilities in this area are as follows:

- RIVER RD. & LONGVIEW AVE. G-622 16.8%
- RIVER RD. & WOODSIDE RD. G-623 12.2%
- RIVERSIDE DR. & RIVER RD. G18717 1.4%
- 4410 RIVER RD. G18718 6.0%
- RIVER RD. & BOX HILL LN. G-515 12.6%
- RIVER RD. & LIME KILN LN. G-624 23.6%
- BLANKENBAKER LN. & RIVER RD. G-335 13.0%
- GLENVIEW AVE. & RIVER RD. G-329 12.3%
- RIVER RD. & RIVERS EDGE RD. SUB. G-600 9.2%
- RIVER RD. PIT SERVING RIVERCREEK. G-590 16.1%
- RIVER RD. & JUNIPER BEACH DR. G-610 5.0%
- RIVER RD. &HARBORTOWN RD. G-621 5.0%

Maximum Allowable Operating Pressure
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 250 psig.

The Longview Ave and Woodside Rd systems have a maximum allowable operating pressure of 10 psig.

The Riverside Dr, Knights of Columbus, Boxhill Ln, and Lime Kiln Ln systems have a maximum allowable operating pressure of 20 psig.
V. River Road Regulator Assemblies (cont’d)

The Blankenbaker Ln and Glenview Ave systems have a maximum allowable operating pressure of 30 psig. These systems are part of the East End 30 psig system (section III). Reinforcements connecting to this system are assumed to take place following the uprate to 50 psig.

The River’s Edge Rd, Juniper Beach Dr, Harbortown Rd, and River Creek Dr systems have a maximum allowable operating pressure of 35 psig.

Recommended Gas System Reinforcements

Reinforcement 1
- Install approximately 2,800 ft of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 840 ft of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and Creekside Ct regulator assemblies and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure
- 5300 Juniper Beach Rd – 34.4 psig

Regulator Operating Capacity
- River Rd & River Creek Dr – 28.9%

Recommended Timeline – 2008-2011

Reinforcement 2
- Uprate River Rd & Woodside Rd medium pressure system from 10 psig to 50 psig.
- Uprate River Rd & Lime Kiln Ln medium pressure system from 20 psig to 50 psig.
- Install approximately 850 ft of 4-inch plastic gas main along Arden Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 1,200 ft of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.
V. River Road Regulator Assemblies (cont’d)

- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Wolfpen Ridge Ct – 32.6 psig

Regulator Operating Capacity
- River Rd & Glenview Ave – 13.2%

Recommended Timeline – 2008-2011

Reinforcement 3
- Uprate River Rd & Longview Ave medium pressure system from 10 psig to 20 psig.
- Install approximately 775 ft of 2-inch plastic gas main along Longview Ln to connect Longview Ave and Boxhill Ln systems.
- Remove the River Rd & Longview Ave regulator assembly

Minimum Gas System Pressure (-12°F)
- 4508 Longview Ln – 11.9 psig

Regulator Operating Capacity
- River Rd & Boxhill Ln – 23.2%

Recommended Timeline – 2008-2011

Reinforcement 4
- Uprate River Rd & Knights of Columbus medium pressure system from 20 psig to 35 psig.
- Install approximately 350 ft of 2-inch plastic gas main along River Rd to connect River’s Edge Rd and Knights of Columbus systems.
- Remove the River Rd & Knights of Columbus regulator assembly.

Minimum Gas System Pressure (-12°F)
- Southeast end of the former Knights of Columbus system – 34.7 psig

Regulator Operating Capacity
- River Rd & River’s Edge Rd – 13.4%

Recommended Timeline – 2008-2011
V. River Road Regulator Assemblies (cont’d)

Reinforcement 5
- Uprate River Rd & Riverside Dr medium pressure system from 20 psig to 50 psig.
- Install approximately 250 ft of 2-inch plastic gas main along Riverside Dr to connect Riverside Dr and Blankenbaker Ln systems.
- Remove the River Rd & Riverside Dr regulator assembly.

Minimum Gas System Pressure (-12°F)
- Wolfpen Ridge Ct – 32.6 psig

Regulator Operating Capacity
- Blankenbaker Ln & River Rd – 13.9%

Recommended Timeline – 2008-2011
River Road Regulator Assemblies – Reinforcement 1

River Creek

Harbortown

Main Extensions

Juniper Beach
VI. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview
The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Maximum Allowable Operating Pressure
This medium pressure system has a maximum allowable operating pressure of 35 psig.

Regulator Operating Capacity
- Watterson Tr and Plantside Dr – 52.4%

Gas System Constraints
Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

Recommended Gas System Reinforcements:

Reinforcement 1
- Install a new medium pressure regulator facility on Tucker Station Road, north of I-64 that is fed from the existing 16-inch high pressure pipeline parallel to I-64.
- Install approximately 1,700 ft of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.
- Install approximately 2,860 ft of 6-inch medium pressure plastic pipeline west from the entrance of the proposed office park, along Tucker Station Road, to the 6-inch main ending on Plantside Drive (near the Papa John’s Building). This would allow for a multiple feed system, improving system reliability.

Minimum gas system pressure (-12°F):
- 3025 Element Ln – 31.23 psig
- 2801 Constant Comment Place – 32.0 psig

Regulator Operating Capacities:
- Tucker Station Rd & I-64 (4x3 Mooney assembly with 35% plates) – 4.4%
- Watterson Tr & Plantside Dr – 46.7%

Recommended Timeline: 2008-2009
Note: This reinforcement should be completed after the Kentucky Department of Transportation widens Tucker Station Road and Pope Lick Road.
Plantside Drive Medium Pressure Gas System – Reinforcement 1

- Eastern Kentucky Line
- New regulator facility
- Install main on Tucker Station Road
- Proposed Business Parks
VII. Jeffersontown/Fern Creek Medium Pressure System

Gas System Overview
The Jeffersontown and Fern Creek areas are part of a large medium pressure gas system that serves the southeastern part of Jefferson County. This system is composed of rural, residential, and small commercial customers and has continued to experience rapid growth in these sectors. The majority of Jeffersontown and Fern Creek areas are served from the following regulator facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator pit at Taylorsville Road and Hopewell Road (Jeffersontown Pit)
- Regulator assembly at Gentry Lane and the Calvary Line
- Regulator pit at Cedar Creek Road and the Calvary Line
- Regulator station at Hudson Lane

Maximum Allowable Operating Pressure
The Jeffersontown/Fern Creek medium pressure gas system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressures (-12 °F)
- 11708 Kewana Ct – 8.6 psig
- 5207 Pine Bunch Ct – 13.4 psig
- 7701 Windgate Dr – 17.5 psig
- 8012 Kendrick Crossing Ln – 10.7 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 14.4%
- Gentry Lane and the Calvary Line – 84.6%
- Cedar Creek Road and the Calvary Line – 8.2%
- Hudson Ln Station – 40.7%

Gas System Constraints
Gas system constraints in this area are primarily due to the infrastructure of small diameter piping coming from the sources. Due to current and anticipated growth it will be necessary to perform gas system reinforcement work.
VII. Jeffersontown/Fern Creek Medium Pressure System (cont’d)

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Jeffersontown/Fern Creek medium pressure distribution system from 35 psig to 60 psig. This uprate consists of approximately 14,123 services and 180 miles of main (107.3 miles of plastic and 70.8 miles of steel).

Minimum gas system pressure (-12°F)
- 11708 Kewana Ct – 34.6 psig
- 5207 Pine Bunch Ct – 39.4 psig
- 7701 Windgate Dr – 40.6 psig
- 8012 Kendrick Crossing Ln – 37.1 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 19.1%
- Gentry Lane and the Calvary Line – 100%
- Cedar Creek Road and the Calvary Line – 11.0%
- Hudson Ln Station – 62.8%

Recommended Timeline – 2008-2010

Reinforcement 2
- Loop approximately 8,370 feet of 6-inch medium pressure gas pipeline along Taylorsville Road from the outlet of the regulator facility to Saratoga Woods Drive.
- Install approximately 1,400 feet of 4-inch medium pressure plastic gas pipe east along Chenoweth Run Road from the 6-inch on Taylorsville Road.

Minimum gas system pressure (-12°F)
- 11708 Kewana Ct – 39.2 psig
- 5207 Pine Bunch Ct – 47.9 psig
- 7701 Windgate Dr – 43.3 psig
- 8012 Kendrick Crossing Ln – 39.8 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 23.6%
- Gentry Lane and the Calvary Line – 100%
- Cedar Creek Road and the Calvary Line – 11.0%
- Hudson Ln Station – 58.8%

Recommended Timeline – 2008-2010
Taylorsville Road/Jeffersontown Medium Pressure Gas System – Reinforcement 2

Looped pipe

4-inch pipe extension

Jeffersontown Pit

Taylorsville Rd

I-265

Stratford Woods Dr
VIII. Bardstown Medium Pressure System

Gas System Overview
The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 2-3 years.

Gas System Reinforcements completed in 2007
Installed approximately 1,800 ft of 8-inch medium pressure pipeline along the Bardstown Bypass (Hwy 245) to connect to the existing 6-inch and 8-inch medium pressure pipe infrastructure.

Gas System Reinforcements to be completed in 2008
Uprate the Bardstown medium pressure system to a maximum allowable operating pressure of 60 psig.

Regulator Facilities
The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

Maximum Allowable Operating Pressure (MAOP)
The Bardstown medium pressure system has a maximum allowable operating pressure of 45 psig.

Model Results

Minimum Gas System Pressure (-12 °F)
- 100 Brighton Ct [13891047] – 35.6 psig

Regulator Operating Capacities
- Bardstown MP – 17.0%
- Chris's Creation MP – 14.5%

Gas System Constraints
Gas system constraints are caused by the lack of a direct gas supply route from the regulator station at the LG&E Bardstown office to the downtown Bardstown area. Due to current and anticipated growth, it will be necessary to reinforce the gas system.
VIII. Bardstown Medium Pressure System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 1,916 ft of 4-inch plastic pipeline along Gilkey Rd and tie into the existing 8-inch steel main on Loretto Rd.

Minimum gas system pressure (-12 °F)
- 160 Deep Springs Dr – 52.4 psig

Regulator Operating Capacities
- Bardstown MP – 17.8%
- Chris's Creation MP – 14.9%

Recommended Timeline – 2009-2011
Note: This reinforcement provides an alternate feed into the system. If Reinforcement 4 is completed, this reinforcement is not needed.

Reinforcement 2
Install approximately 3,177 ft of 4-inch plastic pipeline along Filiatreau Ln and tie into the existing 4-inch plastic main on Glenwood Dr.

Minimum gas system pressure (-12 °F)
- American Dr @ Ballard Springs Ct – 47.9 psig

Regulator Operating Capacities
- Bardstown MP – 19.5%
- Chris's Creation MP – 26.8%

Recommended Timeline – 2010-2012
Note: This reinforcement should be done in conjunction with the expansion of the Highway 605 industrial park. Results include Flowers Foods Bakery.

Reinforcement 3
Uprate Bardstown System from 45 psig to 60 psig. This includes 76.4 miles of main and 3,400 services. Results include Flowers Foods Bakery 55 MCFH load.

Minimum gas system pressure (-12 °F)
- 100 Brighton Ct – 52.1 psig
- American Dr @ Ballard Springs Ct – 30.2 psig

Regulator Operating Capacities
- Bardstown MP – 20.4%
- Chris's Creation MP – 14.5%
VIII. Bardstown Medium Pressure System (cont’d)

Recommended Timeline – 2010

Note: This reinforcement is being done to support the expansion of the Highway 605 industrial park.

Reinforcement 4
Install a high pressure distribution regulator facility (2 – 4” Mooney 100%) upstream of the existing medium pressure facility at Chris’s Creations. Install 9,200 feet of 8-inch steel from the new facility to the medium pressure plastic installed in Reinforcement 3. Tie-in to existing medium pressure main with a new 4X3 Mooney regulator facility.

Minimum gas system pressure (-12 °F)
- Brighton Ct– 52.6 psig

Regulator Operating Capacities
- Bardstown MP – 15.8%
- Chris's Creation MP – 41.8%
- Bardstown MP 2 (NEW) – 10.6%

Recommended Timeline – 2009

Note: This reinforcement is being done to support the expansion of the Highway 605 industrial park. This reinforcement provides an alternate feed into the system.

Reinforcement 5
Install a medium pressure regulator facility off the high pressure transmission line at the intersection of North Third Street and the Bardstown Bypass (Hwy 245).

Note: Based on Reinforcement 1 of the Mt. Washington/Lebanon Junction High Pressure System (see Section XVIII; see also Section XXIII, Scenario 2), the new regulator facility would allow gas to feed directly into the center of the system to eliminate the low-pressure problem at Meadow Ridge Dr. The new low pressure point is located east of the Bardstown MP facility.

Minimum gas system pressure (-12 °F)
- 160 Deep Springs Dr – 34.7 psig
- 116 Andrea Ct – 33.7 psig
- 212 Meadow Ridge Dr – 43.3 psig

Regulator Operating Capacities
- Bards2MP (new pit) – 11.8%
- Bardstown MP – 5.8%
- Chris's Creation MP – 18.9%

Recommended Timeline – TBD
Note: Should be completed in conjunction with the Mt. Washington/Lebanon Junction high-pressure pipeline project.
Bardstown Medium Pressure Gas System – Reinforcement 2
Bardstown Medium Pressure Gas System – Reinforcement 5

Mt. Washington /Lebanon Junction high-pressure pipeline

Bards2MP (new pit)

Hwy 31 E

44.75 psig
IX. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and HiLand
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Hwy 44 and Boardwalk

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on Winding Woods Trail (30.4 psig).
IX. Highway 44 Regulator Assemblies (cont’d)

Regulator Operating Capacities
- Mt Washington MP – 9.3%
- Hwy 44 and Woodlake – 21.5%
- Hwy 44 and Harris – 21.0%
- Hwy 44 and Fisher – 74.5%
- Hwy 44 and Greenbrian – 33.8%
- Hwy 44 and Bethel Church – 17.6%
- Hwy 44 and Azure – 6.8%
- Hwy 44 and Truman – 21.0%
- Hwy 44 and Kennedy – 5.7%
- Hwy 44 and Bogard – 45.1%
- Hwy 44 and Bells Mill – 19.2%
- Hwy 44 and Alpar – 3.8%
- Hwy 44 and Mockingbird – 43.1%
- Hwy 44 and Sunview – 42.1%
- Hwy 44 and Watergate – 1.1%
- Hwy 44 and HiLand – 5.3%
- Hwy 44 and Big Clifty – 8.3%
- Hwy 44 and Halls – 3.0%
- Hwy 44 and Boardwalk – 11.5%

Recommended Gas System Reinforcements

Reinforcement 1
- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 570 feet of 4-inch plastic main along Hwy 44.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,350 ft of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Tanager Landing Apartments off Hwy 44 – 34.5 psig

Regulator Operating Capacities
- Hwy 44 and Halls Ln – 24.8%

Recommended Timeline – 2009-2011
IX. Highway 44 Regulator Assemblies (cont’d)

Reinforcement 2
- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,780 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

*Minimum Gas System Pressure (-12°F)*
- Douglass Drive – **34.9 psig**

*Regulator Operating Capacities*
- Hwy 44 and Hi-Land – **6.7%**

*Recommended Timeline – 2009-2011*

Reinforcement 3
- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.

*Minimum Gas System Pressure (-12°F)*
- Old Hickory Lane – **29.4 psig**

*Regulator Operating Capacities*
- Hwy 44 and Sunview – **90.9%**

*Recommended Timeline – 2009-2011*
*Note:* Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4
- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,200 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

*Minimum Gas System Pressure (-12°F)*
- 440 East Millwater Falls – **31.3 psig**

*Regulator Operating Capacities*
- Hwy 44 and Bells Mill – **22.9%**

*Recommended Timeline – 2009-2011*
IX. Highway 44 Regulator Assemblies (cont’d)

Reinforcement 5
- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,900 feet of 6 inch plastic main along Hwy 44.
- Connect Systems served by Bethel Church and Highland Springs facilities with 1,300 feet of 4- or 6-inch plastic main along Hwy 44.
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, and Bethel Church Road facilities.

Minimum Gas System Pressure (-12°F)
- Winding Woods Trail – 27.2 psig

Regulator Operating Capacities
- Hwy 44 and Bogard – 60.1%
- Hwy 44 and Azure – 22.8%
- Hwy 44 and Highland Springs – 6.7%

Recommended Timeline – 2009-2011

Reinforcement 6
- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,650 feet of 6-inch plastic pipe between Harris and Woodlake.
- Convert approximately 34 high-pressure services to medium pressure.
  Note: Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

Minimum Gas System Pressure (-12°F)
- Winding Woods Trail – 27.2 psig

Regulator Operating Capacities
- Hwy 44 and Fisher – 74.6%
- Hwy 44 and Woodlake – 53.0%

Recommended Timeline – 2009-2011
Hwy 44 Regulator Assemblies – Reinforcement 1

2-inch Main Extension

Hwy 44 and Halls Ln
Regulator Assembly

Big Clifty

Boardwalk
Hwy 44 Regulator Assemblies – Reinforcement 5
X. Hodgenville Medium Pressure System

Gas System Overview
The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

Regulator Facilities
The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

Maximum Allowable Operating Pressure
The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is located at 2017 US Highway 31E (15.8 psig).

Regulator Operating Capacity
- Highway 84 and Glendale Rd – 15.0%

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Hodgenville medium pressure gas distribution system to 50 psig. This uprate will affect approximately 1,241 services and 25.3 miles of pipeline.

Minimum Gas System Pressure (-12°F)
- 2017 US Highway 31E – 47.7 psig

Regulator Operating Capacity
- Highway 84 and Glendale Rd – 15.8%

Recommended Timeline – 2008-2009
XI. Waste Management Relocation Project

Gas System Overview
The Penile City Gate Station supplies gas to the Preston City Gate Station via a 20-inch transmission pipeline (the Penile to Preston Line). The Penile to Preston Line crosses Waste Management landfill property from the Outer Loop to I-65. The two primary feeds associated with this pipeline are from the Penile and Preston City Gate Stations. Due to planned construction at the landfill, approximately 6,000 ft of the Penile to Preston Line that run through the landfill property must be relocated.

Maximum Allowable Operating Pressure
The Penile to Preston Line has a maximum allowable operating pressure of 420 psig.

Recommended Relocation
Shift the portion of the pipeline that runs through landfill property approximately 500 ft to the southeast. The pipeline should roughly run along an access road in the landfill and should reconnect with the existing pipeline before it crosses underneath I-65. This relocation will require approximately 6,600 ft of 20-inch high-pressure pipeline.

Recommended Timeline – 2008 - 2009
Waste Management Relocation Project – Recommended Relocation
XII. Minor Lane Heights Renaissance Zone

Gas System Overview
The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Gas System Reinforcement Completed in 2007
- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 ft of 8-inch plastic main along Outer Loop, Stinnett Ln, proposed Air Commerce Way to serve UPS facility.

Regulator Facilities
The regulator facilities that feed this system are as follows:
- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure
The Minor Lane Heights system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at 2240 Outer Loop (29.9 psig). There is another low pressure point at the south end of Eagle Pass (29.6 psig).

Regulator Operating Capacities
- Preston City Gate Station MP – 49.3%
- Outer Loop and Grade Ln – 29.2%

Gas System Constraints
Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.
XII. Minor Lane Heights Renaissance Zone (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Install and remove gas mains according to “An Analysis of the Minors Lane Heights Renaissance Zone” dated 15 January 2007 or the latest version.

- Retire existing pipelines in the area.
- Install approximately 1,200 ft of 2-inch pipe
- Install approximately 15,400 ft of 4-inch pipe
- Install approximately 5,600 ft of 8-inch pipe

Minimum Gas System Pressure (-12°F)
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) – 32.3 psig

Regulator Operating Capacities
- Preston City Gate Station MP – 53.1%
- Outer Loop and Grade Ln – 41.5%

Recommended Timeline – 2009-2019
Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 1
XIII. Mount Washington Medium Pressure System

Gas System Overview
The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

Regulator Facilities
The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:

- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

Maximum Allowable Operating Pressure (MAOP)
The Mount Washington medium pressure gas system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 °F);
The predicted minimum pressure is located on Pin Oak Drive (37.4 psig).

Regulator Operating Capacities (-12 °F):
- Mt. Washington MP – 9.3%
- Bardstown Rd and Landis Ln – 42.1%

Gas System Constraints
Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 4,300 ft of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

Minimum Gas System Pressure (-12 °F)
- Pin Oak Dr – 51.7 psig
XIII. Mount Washington Medium Pressure System (cont’d)

Regulator Operating Capacities (-12 °F):
- Mt. Washington MP – 8.0%
- Bardstown Rd and Landis Ln – 39.9%
- Vista Hills Blvd and Calvary Line – 100%

Recommended Timeline – 2008-2009
Mount Washington Medium Pressure System – Reinforcement 1

Main Extension
XIV. Preston High Pressure Distribution Pipeline Reinforcement

Gas System Overview
The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure
The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this high pressure system is located at the inlet to the Preston and Antle regulator pit (68.5 psig)

Regulator Operating Capacities
- Preston City Gate Station – 37.2%

Gas System Constraints
Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
The State Highway Department plans on completing a corridor alignment along Cooper Chapel Road, in the City of Okolona.
- Install approximately 31,850 ft of 12-inch high pressure gas pipeline from the Calvary line to the Preston high pressure line.
- Install a new regulator facility (4x3 Mooney assemblies with 100% plates) at Preston Highway and Cooper Chapel Road to reduce the pressure from the Calvary Line to 110 psig.

Minimum Gas System Pressure (-12°F)
- Preston and Antle inlet – 96.3 psig

Regulator Operating Capacities
- New facility at Cooper Chapel and Preston Highway – 42.3%
XIV. Preston High Pressure Distribution Pipeline Reinforcement (cont’d)

Eventually, the pipeline would be extended further south along Preston Highway and this would allow a second feed for the high pressure system (see Section XIX). Without the second feed, if the Preston high pressure pipeline was damaged, the areas of Okolona and Maryville and a portion of Shepherdsville would be lost.

Recommended Timeline – TBD

Reinforcement 2
- Extend the 8-inch steel high-pressure main south along Preston Highway from Mud Lane to Bells Mill Road (approx. 19,000 feet).
- Install a medium pressure regulator facility at Bells Mill Road and Preston Highway (4x3 Mooney with 100% plates) to be tied into the 8-inch medium pressure main on Preston Highway or Bells Mill Road.

Minimum Gas System Pressure (-12°F)
- Inlet to new Facility at Preston & Bells Mill – 70.5 psig

Regulator Operating Capacities
- Cooper Chapel and Preston – 49.9%
- Preston and Antle – 58.2%
- Preston and Bells Mill – 100%

Note: The current pressure on the Preston HP line prohibits a significant pressure differential across the new regulator assembly. The results shown are after Reinforcement 1 has been completed and assuming Shepherdsville/Northern Bullitt MP system has been uprated. Operating the Preston HP line at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the new assembly.

Recommended Timeline – TBD; after completion of Reinforcement 1
XV. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 °F).
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 °F) with the proposed gas loads for 2005 and the Mount Washington high pressure system operating at 275 psig.
- Approximately 60-65 MCFH of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 56 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.
- LG&E can meet gas load projections until 2016 with a 2% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2016.
- LG&E can meet gas load projections until 2012 with a 4% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2012.
XV. **Mt. Washington/Lebanon Junction High Pressure Distribution System (cont’d)**

- LG&E can meet gas load projections until 2011 with a 5% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2011.

**Recommended Gas System Reinforcements**

**Reinforcement 1**
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

**Recommended Timeline – 2012**

**Note:** For further information regarding proposed reinforcements to this system, see Section XXII.
Mt. Washington High Pressure Distribution System – Reinforcement 1

- Jim Beam Clermont
- New regulator facility
- 8-inch high pressure extension
- Publishers Printing
- Jim Beam Boston
- Bardstown
XVI. Shepherdsville/Northern Bullitt County Medium Pressure System

Gas System Overview
The Shepherdsville/Northern Bullitt medium pressure gas system serves residential and commercial customers in the City of Shepherdsville and outlying areas between I-265 and Hwy 44.

Regulator Facilities
The regulator facilities that supply gas to the Shepherdsville/Northern Bullitt medium pressure system are as follows:

- Regulator pit at Lee's Lane and Highway 44
- Regulator pit at Cedar Grove Road and I-65
- Regulator pit at Mud Lane and Antle Drive
- Regulator pit at Old Bardstown Road and Thixton Lane
- Regulator pit at Vista Hills Blvd and Calvary Line

Maximum Allowable Operating Pressure
The Shepherdsville/Northern Bullitt medium pressure gas system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this medium pressure system is located at 8804 Cedar Creek Rd (39.8 psig)

Regulator Operating Capacities
- Hwy 44 and Lee’s Ln – 36.6%
- Cedar Grove Rd and I-65 – 14.7%
- Mud Ln and Antle Dr – 100%
- Old Bardstown Rd and Thixton Ln – 6.4%
- Vista Hills Blvd and Calvary Line – 47.6%

Gas System Constraints
Gas system constraints in this area are due to an infrastructure of small diameter pipe in the Thixton Lane and Cedar Creek Road areas in the northeastern portion of this system. There is also a severe lack of redundancy in this area which is adding to the pressure problems. Making the system more redundant in this area would prevent outages due to third-party damage or other causes.

A public works project is planned to widen (and reroute) a portion of Preston Hwy between Shepherds Way and Hebron Ln.
XVI. Shepherdsville/Northern Bullitt County Medium Pressure System (cont’d)

Recommended Gas System Reinforcements:

Reinforcement 1
Install approximately 4,200 feet of 6-inch plastic main on Thixton Lane from Taylor Rae Drive south to the existing 6-inch plastic main located near 8506 Thixton Lane.

Minimum gas system pressure (-12 °F)
• 517 Lakes of Dogwood Blvd – **40.7 psig**

Regulator Operating Capacities
• Hwy 44 and Lee’s Ln – **36.2%**
• Cedar Grove Rd and I-65 – **14.8%**
• Mud Ln and Antle Dr – **100%**
• Old Bardstown Rd and Thixton Ln – **7.5%**
• Vista Hills Blvd and Calvary Line – **100%**

Recommended Timeline – 2009

Reinforcement 2
• Extend 1,700 feet of 6-inch plastic main from John D. Harper Blvd to Cobblestone Way to serve customers and the subdivision disconnected from the 8-inch main on Preston Hwy.
• Extend 1,500 feet 4-inch plastic main from John D Harper Blvd south to Hebron Lane.
• Extend 500 feet of 6-inch main from Lodie Lane, across Preston Hwy, and reconnect to the Cobblestone Way 6-inch main

Minimum gas system pressure (-12 °F)
• 8804 Cedar Creek Rd – **42.6 psig**
• Reichmuth Ln – **46.9 psig**

Recommended Timeline – Concurrent with the highway work along Preston Highway.
Shepherdsville/N. Bullitt Medium Pressure System – Reinforcement 1

Install 6-inch Main

Taylor Rae Drive

Thixton Lane

Zoneton Road
Shepherdsville/N. Bullitt Medium Pressure System – Reinforcement 2

Cambridge Court
W. Hebron Lane
John D Harper Blvd
Cobblestone Way
Lodie Lane
4-inch Main
6-inch Main Relocation
6-inch Main
W. Hebron Lane
XVII. Brandenburg High Pressure System

Gas System Overview
The Brandenburg high-pressure distribution system serves the cities of Brandenburg and Doe Valley, and the surrounding area. Gas is supplied from Doe Run storage field lines at Riggs Junction. The Brandenburg area continues to experience residential and commercial growth.

Note: The pipeline in this system may be in poor condition. Field data collected during the 2002/2003 heating season indicated pressure loss higher than predicted from the system model. This may be due to water intrusion and iron sulfide in the pipeline. Further data should be collected to monitor the condition of this pipeline.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is at the inlet of the regulator pit serving the Brandenburg medium-pressure system located at Old US 60 and Highway 933 (105.8 psig).
XVIII. Radcliff/Fort Knox Medium Pressure System

Gas System Overview
The Radcliff/Fort Knox medium pressure system serves approximately 4,600 residential and small commercial customers. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/ Fort Knox area over the next 8 years.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W Vine Street.

Maximum Allowable Operating Pressure
The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at 1004 Muirfield Ct (32.7 psig).

Regulator Operating Capacity (includes asphalt plant load):
- Radcliff #1: 19.6% (31.8%)
- Radcliff #2: 69.2% (50.7%)

Gas System Constraints
The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off St. Andrews Dr will require significant reinforcement.
XVIII. Radcliff/Fort Knox Medium Pressure System (cont’d)

Recommended Gas System Reinforcement

Reinforcement 1
- Replace existing regulators in Radcliff #2 with 4x3 Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 60 psig.

Note: Additional BRAC load was estimated to be 240 MCFH based on anticipated number of new residences and current load.

Minimum gas system pressure (-12°F)
- Hood Ln in the Yarwood Mobile Home Park (57.3 psig)
- 568 St. Andrews Rd (54.4 psig)

Regulator Operating Capacities
- Radcliff #1 – 33.9%
- Radcliff #2 – 20.7%

Recommended Timeline – 2009-2011

Reinforcement 2
- Install 4,800’ of 4-inch PL main in Otter Creek Rd from existing 4-inch CT to 2-inch PL in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.
XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System

Gas System Overview
The Crestwood/Pee Wee Valley/Simpsonville medium-pressure system will require reinforcement to continue to serve the Norton Commons development and the Old Brownsboro Crossing commercial park, which includes a professional medical center, office buildings, and retail/restaurants. This system also feeds near Persimmon Ridge and the Polo Fields. It has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System. There are a few options available that will provide adequate pressures throughout the system.

Gas System Reinforcement Completed in 2007

- Old Henry Road Reinforcement
  - Install 5,700 ft of 8-inch medium pressure pipe north along Old Henry Rd to tie into the 8-inch main at 9207 Ash Land Ct.

Maximum Allowable Operating Pressure
The Crestwood/Pee Wee Valley/Simpsonville medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum gas system pressure (-12 ⁰F)
- Sasse Way – 13.6 psig

Regulator Operating Capacities
- HWY 1694 & WORTHINGTON LN – 14.7%
- OLD HENRY RD & TERRA CROSSING BV – 24.8%
- CONNER STATION & COLT RUN RD – 6.2%
- CRESTWOOD & OLD LAGRANGE RD. G-381 – 42.9%
- LAKESHORE DR. & OLD VEECHDALE RD G13108 – 40.3%
- ENGLISH STATION WAY G-580 – 51.0%
- WESTPORT RD.& MURPHY LN. G-456 – 84.3%
- OLD LAGRANGE RD.& COLLINS LN. G-578 – 26.9%
XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)

Recommended Gas System Reinforcements

Reinforcement Option 1
Loop approximately 7,150 feet of existing 4-inch medium pressure steel and plastic main with 6-inch plastic main along State Hwy 362 (Ash Avenue) from LaGrange Road, southeast to the existing 6-inch plastic main near Ashbrooke Drive.

Minimum gas system pressure (-12 °F)
- 2629 Hedgepath Trl – 19.9 psig
- 3405 Sasse Way – 13.0 psig
- 1601 Keever Court – 19.3 psig

Reinforcement Option 1a
This reinforcement would be the same as Option 1, but instead of using 6-inch plastic main for the loop, 8-inch plastic main would be used.

Minimum gas system pressure (-12 °F)
- 2629 Hedgepath Trl – 20.4 psig
- 3405 Sasse Way – 12.8 psig
- 1601 Keever Court – 19.8 psig

Reinforcement Option 2
Loop approximately 3,050 feet of 4-inch medium pressure steel main with 8-inch plastic main along LaGrange Road from the existing 8-inch steel main near Altawood Court, northeast to State Hwy 362 (Ash Avenue).

Minimum gas system pressure (-12 °F)
- 2629 Hedgepath Trl – 19.5 psig
- 3405 Sasse Way – 20.2 psig
- 1601 Keever Court – 19.0 psig

Reinforcement Option 3
This option would combine the main replacements from Option 1/1a and Option 2. For this option we would need to install 3,050 feet of 8-inch plastic main and 7,150 feet of 6-inch or 8-inch plastic main for a total of 10,200 feet of plastic main.

Minimum gas system pressure with Option 1 & 2 (-12 °F)
- 2629 Hedgepath Trl – 26.1 psig
- 3405 Sasse Way – 20.0 psig
- 1601 Keever Court – 25.2 psig

Minimum gas system pressure with Option 1a & 2 (-12 °F)
- 2629 Hedgepath Trl – 26.8 psig
- 3405 Sasse Way – 19.8 psig
- 1601 Keever Court – 25.9 psig
**XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)**

Reinforcement Option 4
This option would require the installation of approximately 5,300 feet of 6-inch medium pressure plastic main along Flat Rock Road between Robin Lane and Curry Branch Road.

*Minimum gas system pressure (-12 °F)*
- 2629 Hedgepath Trl – 18.9 psig
- 3405 Sasse Way – 15.2 psig
- 1601 Keever Court – 16.8 psig

Reinforcement Option 5
This option would require looping approximately 6,300 feet of 4-inch medium pressure steel main with 8-inch plastic main along Shelbyville Road beginning at the existing 8-inch steel main near Waterstone Way, east to Flat Rock Road.

*Minimum gas system pressure (-12 °F)*
- 2629 Hedgepath Trl – 22.5 psig
- 3405 Sasse Way – 16.2 psig
- 1601 Keever Court – 22.7 psig

Reinforcement Option 6
This reinforcement project combines Option 4 and Option 5. The main needed for this project would be 6,300 feet of 8-inch plastic and 5,300 feet of 6-inch plastic for a total of 11,600 feet of plastic main.

*Minimum gas system pressure (-12 °F)*
- 2629 Hedgepath Trl – 29.9 psig
- 3405 Sasse Way – 18.8 psig
- 1601 Keever Court – 28.7 psig

Reinforcement Option 7
This reinforcement project combines Options 1a, 2, 4, and 5. The main needed for this project would be 16,500 feet of 8-inch plastic main and 5,300 feet of 6-inch plastic main for a total of 21,800 feet of plastic main.

*Minimum gas system pressure (-12 °F)*
- 2629 Hedgepath Trl – 34.7 psig
- 3405 Sasse Way – 22.3 psig
- 1601 Keever Court – 33.4 psig
XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)

Reinforcement Option 8
This option requires installing approximately 13,400 feet of 6-inch plastic main on Todds Point Road from the existing 4-inch plastic main near Chapel Drive, southeast to the existing 6-inch plastic main on Aiken Road. Also, an additional 3,400 feet of 6-inch plastic main would need to be installed on State Hwy 1818 from Todds Point Road, northeast to Abbott Lane to connect with a small existing 35 psig system. This existing system would have to be uprated from 35 psig to 50 psig, and the orifice plates at the Abbotts Ln & Myers Ln regulator assembly would need to be changed to 1/2”. This option would require installing a total of 16,800 feet of 6-inch plastic main and would require uprating the system consisting 116 services from 35 psig to 50 psig. While this option may not be currently feasible, it would provide another feed into this area and allow for additional growth.

Minimum gas system pressure (-12 °F)
- 2629 Hedgepath Trl – 34.5 psig
- 3405 Sasse Way – 22.1 psig
- 1601 Keever Court – 32.9 psig
Crestwood/Pee Wee Valley/Simpsonville Reinforcement Options 1-8

- Option 3: Combines Option 1/1a and Option 2
- Option 6: Combines Option 4 and 5
- Option 7: Combines Option 1a, 2, 4 and 5
XX. Appendix – Mt. Washington High Pressure Distribution System

Options Considered
An attempt was made to parallel the existing 8-inch and 6-inch piping in order to solve the pressure and capacity problems. Almost the entire route (approximately 21 miles) of the system would have to be paralleled in order to correct the pressure and capacity problems.

Scenario 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Preston Highway regulator station to the Shepherdsville regulator pit at Lee Lane and Highway 44 (approximately 12.5 miles). In addition, the existing 6-inch piping (approximately 12 miles) would have to be paralleled in order to alleviate the restriction to moving the gas to the south end of the system.

*Project estimated cost: $10.9 MM*

Scenario 2
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

*Project estimated cost: $6.2 MM*

Scenario 3
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

*Project estimated cost: $5.8 MM*
Scenario 4
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line to the south end of the system. This would require installing approximately 16 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

Project estimated cost: $7.1 MM

Scenario 5
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line along Hwy 509 and Hwy 245 into Lebanon Junction. This would require installing approximately 12.5 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Project estimated cost: $5.5 MM
Mt. Washington High Pressure Distribution System – Overview

- PRK
- Fairdale
- Okolona
- Maryville
- Lebanon Junction, Kentucky
- Bardstown
- Maywood
- Rineyville
- West Point
- Muldraugh
- Radcliff

LG&E Muldraugh and Magnolia Gas Transmission Pipelines

LG&E Calvary Gas Transmission Pipeline

LG&E Magnolia Gas Transmission Pipelines
Mt. Washington High Pressure Distribution System – Mt. Washington Overview
Mt. Washington High Pressure Distribution System – Scenario 1

Preston Hwy Station

Lees Ln & Hwy 44

Preston Hwy 12.5 mile extension

Fairdale

Mt. Washington

Shepherdsville

Maryville

Mt. Washington High Pressure Distribution System – Scenario 1

Preston Hwy Station

Lees Ln & Hwy 44

Preston Hwy 12.5 mile extension

Fairdale

Mt. Washington

Shepherdsville

Maryville
Mt. Washington High Pressure Distribution System – Scenario 2

- Jim Beam Clermont Plant
- Location of new LG&E regulator facility
- Lebanon Junction
- Publishers Printing
- Jim Beam Boston Plant
- 8-inch high pressure extension 14.0 miles along Hwy 245
- LG&E Calvary Gas Transmission Pipeline
Mount Washington/Lebanon Junction High Pressure Gas System – Scenario 3

- Radcliff
- Muldraugh
- West Point
- Parkview
- Mt Washington
- Maryville
- Shepherdsville
- Jim Beam Clermont
- Jim Beam Boston
- Hwy 434 13 mile extension

New Regulator Facility
Publishers Printing
Mt. Washington High Pressure Distribution System – Scenario 4

- Mt. Washington
- Maryville
- Shepherdsville
- Bardstown
- New Regulator Facility
- Jim Beam Clermont
- Hwy 245/Cross Country
- Jim Beam Boston
- Muldraugh
- Radcliff
- West Point
- Jim Beam Boston
Mt. Washington High Pressure Distribution System – Scenario 5

Hwy 509
(12.5 miles)

New Regulator Facility

Jim Beam Clermont

Publishers Printing

Jim Beam Boston

Bardstown
Louisville Gas and Electric

Gas System Planning
Gas Construction Plan

August 2010
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I.  **Crestwood-Eminence-Bedford High Pressure Distribution System**

**Gas System Overview**
The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is supplied by the Eminence, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

**Regulator Facilities**
The regulator facilities that feed this system are as follows:

- Elder Park City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

**Maximum Allowable Operating Pressure**
From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

**Model Results**

**Minimum Gas System Pressure (-12°F)**
The predicted minimum gas system pressure is at 4021 Hwy 146 (80.93 psig).

**Regulator Operating Capacities**
- Elder Park City Gate Station – 16.9%
- Crestwood City Gate Station – 56.8%
- Bedford City Gate Station – 100%

**Note:** The reported capacities are without the proposed gas regulation equipment upgrades at the Bedford city gate station (2010) and the Crestwood city gate station (2011).

**Gas System Constraints**
The system is composed primarily of 4-inch pipeline, limiting the system’s capacity for expansion.
I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Connect the Ballardsville gas transmission line to the Crestwood-Bedford high pressure system with 5,800 feet of 8” steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22. **NOTE:** This reinforcement is referenced in Section II as part of Reinforcement 1.

*Minimum Gas System Pressure (-12°F)*
- 4021 Hwy 146 – **163.61 psig**

*Regulator Operating Capacities*
- Elder Park City Gate Station – **17.4%**
- Crestwood City Gate Station – **50.7%**
- Bedford City Gate Station – **100%**
  *Recommended Timeline – 2010-2013*

Reinforcement 2
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location. If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood-Bedford line should a failure occur.

*Minimum Gas System Pressure (-12°F)*
- Inlet to Pleasureville – **68.7 psig**

*Regulator Operating Capacities*
- Bedford City Gate Station – **73.4%**
- Crestwood City Gate Station – **57.8%**

*Recommended Timeline – 2010-2015*

Reinforcement 3
- Install a new city gate station near L’Esprit Farms at the intersection of East Highway 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along East Highway 146 to connect with the Elder Park/Ballardsville pipeline.
- Install a regulator station where Hwy 146 connects with the Elder Park/Ballardsville pipeline to lower the pressure to 100 psig from the new city gate station.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford high pressure pipeline at Smithfield Rd).
I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont’d)

Minimum Gas System Pressure (-12°F)
- 4021 Hwy 146 – 270.25 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 16.3%
- Crestwood City Gate Station – 37.4%
- Bedford City Gate Station – 90%

Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 1
II. East End Gate Stations

Gas System Overview
The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure
The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints
If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the Zorn Ave regulator station (253.6 psig).

The predicted minimum gas system pressure on the Crestwood system is located at 4021 Hwy 146 (80.9 psig).

The predicted minimum gas system pressure on the LaGrange system is located at 20 Quality Place (86.5 psig).

Regulator Operating Capacities
- Elder Park City Gate Station – 16.9%
- Crestwood City Gate Station – 56.81%
- LaGrange City Gate Station – 46.7%

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions
- Operate the Elder Park City Gate Station at 350 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig
II. **East End Gate Stations (cont’d)**

**Reinforcement 1**
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 7,500 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,800 feet of 8-inch pipeline.

**Minimum Gas System Pressure (-12°F)**
- Zorn Inlet – 311.1 psig
- 4021 Hwy 146 – 224.4 psig

**Regulator Operating Capacities**
- Elder Park City Gate Station – 19.3%
- Crestwood City Gate Station – 32.2%
- LaGrange City Gate Station – 46.7%

**Recommended Timeline – 2010 - 2015**

**Reinforcement 2**
Connect the Elder Park system to the LaGrange system

- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,400 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.

**Minimum Gas System Pressure (-12°F)**
- Zorn Inlet – 310.8 psig
- Springhouse Estates Inlet – 88.6 psig
- 4701 Hwy 146 – 80.9 psig

**Regulator Operating Capacities**
- Elder Park City Gate Station – 18.8%
- Crestwood City Gate Station – 56.8%
- LaGrange City Gate Station – 29.1%

**Recommended Timeline – 2010 – 2015**
East End Gate Stations – Reinforcement 1

- Elder Park City Gate Station
- Hwy 53 Main Extension
- Hwy 393 Main Extension
- Crestwood City Gate Station
East End Gate Stations – Reinforcement 2
III. LaGrange Medium Pressure Systems

Gas System Overview
The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure
These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

Minimum Gas System Pressure (-12°F)

<table>
<thead>
<tr>
<th>Sub-System MAOP</th>
<th>Location</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 psig systems</td>
<td>3500 Mattingly Rd [6447519]</td>
<td>7.4 psig</td>
</tr>
<tr>
<td>30 psig system</td>
<td>Parker Pl [6480299]</td>
<td>21.7 psig</td>
</tr>
<tr>
<td>35 psig systems</td>
<td>Kamer Ct [6430958]</td>
<td>28.7 psig</td>
</tr>
</tbody>
</table>

Regulator Operating Capacities:

35 psig Systems
- Hoffman Ln & Parkview Manor – 3.8%
- Button Ct & Commerce Pkwy G-21254 – 19.3%
- Allen Ln & Artisan Pkwy – 6%
- Hwy 53 & Cherry Creek Dr – 37.3%
- New Cedar Point Rd. & Old LaGrange G-364 – 54.3%
- Elder Park Rd. G-433 – 35.9%
- Moody Ln & Hwy 53 G-559 – 23.8%
- E. Moody Ln.& Cal Avenue G-593 – 7.8%
- Deer Run Drive G-553 – 14.1%
- Granger Rd. & Hwy 53 G-545 – 34%
- Park Rd. & Hwy 53 G-558 – 19.8%
- Zhale Smith Rd & Hwy 53 G-591 – 9.9%
- Springhouse Estates Section 1 G-599 – 71.6%
- Hwy 146 & Fort Pickens Rd G13112 – 0.0%
- Prestwick Dr. & Hwy. 53 G13115 – 38.6%
- Crystal Dr.& Grange Dr. G18329 – 22.6%
III. LaGrange Medium Pressure Systems (cont’d)

30 psig systems
- Regulator pit at Woodlawn Ave and Lagrange Rd – 16%
- Lagrange medium pressure regulator pit – 69.8%
- Regulator pit at Hoffman Ln – 47.1%

10 psig systems
- Regulator pit at Hwy 146 – 20.4%
- Regulator pit at Hwy 393 & Hwy 146 – 1.2%
- Regulator pit at Kings Ln & Hwy 146 – 1.6%
- Regulator assembly at Georgie Way and Moody Ln – 4%
- Regulator assembly at Hazelwood Dr & Elder Park Rd – 14.1%
- Regulator assembly at Sycamore Rd and Elder Park Rd – 26.8%

Gas System Constraints
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

Gas System Reinforcements Note
- Due to economic conditions, these plans have been put on hold for the time being.

Recommended Gas System Reinforcements:

Reinforcement 1
Extend gas mains and uprate LaGrange MP system as described in “An Analysis of the OCEDA Economic Development Campus” dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 Mcfh. The proposed reinforcement project requires installing:

- 15,000 ft of 4 inch pipe
- 4,000 ft of 6 inch pipe
- 12,000 ft of 8 inch pipe
- An uprate of 11.6 miles of existing pipeline and 467 existing customers
- A new regulator facility at Moody Lane and North Fible Lane

Minimum gas system pressure (-12°F):
- 2300 Stonybrook Ct – 42.7 psig

Regulator Operating Capacities:
- Moody Ln and North Fible Ln – 15.5%
- Granger Rd and Hwy 53 – 46.6%
- Elder Park Rd – 32.9%

Recommended Timeline – TBD
III. **LaGrange Medium Pressure Systems (cont’d)**

Reinforcement 2
Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in “An Analysis of Proposed Development at Buckner Crossings” dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90 Mcfh. The proposed reinforcement requires installing:

- 5,100 ft of 6-inch pipe
- 5,300 ft of 4-inch pipe
- 13,100 ft of 2-inch pipe
- Uprate 400 ft of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

**Minimum Gas System Pressure (-12°F)**
- Southern Patio Home Area – **29.3 psig**

**Regulator Operating Capacity**
- Hwy 393 & Commerce Pkwy – **89.4%**
- Commerce Pkwy & Button Court Ln – **18%**
LaGrange Medium Pressure Gas System – Reinforcement 1

OCEDA Development Area

New facility at Moody Lane and North Fible

Moody Lane

HWY 53
LaGrange Medium Pressure Gas System – Reinforcement 2

Button Court Ln

Hwy 393 & Hwy 146

Buckner Crossing Development Area

New Regulator Pit at Hwy 393 & Commerce Pkwy
IV. River Road Regulator Assemblies

Gas System Overview
Gas System Planning has identified eight regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park pipeline.

Gas System Reinforcement Completed in 2007
As part of the Farm Tap upgrade project, several medium pressure reinforcements have been made, resulting in the removal of two River Road assemblies. The reinforcements are:

- Installed 1,900 feet of 4-inch PL main in River Road from River Creek Dr up to Harrods Creek. Tie-in to regulator assembly at River Rd & Creekside Ct, uprate the River Creek Drive system from 10-35 psig and remove the Creekside Ct regulator assembly. New main will allow eventual tie-in to Harrods Creek MP system and retirement of River Creek Dr regulator assembly.
- Installed 2,200 feet of 4-inch PL main in River Road from 7009 River Rd to 7314 River Rd. Tie in to systems at River Rd & Private Dr, River Rd & Transylvania and River Rd & Mayfair Rd. Retire regulator assemblies at Private Dr and Mayfair Rd.

Regulator Facilities
The regulator facilities in this area with their operating capacity and maximum allowable operating pressure are as follows:

- River Road & Longview Avenue. G-622 - 18% (MAOP=10 psig).
- River Road & Woodside Road. G-623 - 15.9% (MAOP=35 psig).
- River Road & Box Hill Lane. G-515 - 13.3% (MAOP=20 psig).
- River Road & Lime Kiln Ln. G-624 - 25.3% (MAOP=20 psig).
- Blankenbaker Lane & River Road. G-335 - 12.3% (MAOP=50 psig).
- Glenview Ave. & River Road. G-329 - 14.4% (MAOP=50 psig).
- River Road & Rivers Edge Rd Sub. G-600 - 13.4% (MAOP =35 psig).
- River Road pit serving Rivercreek G-590 - 24.2% (MAOP=35 psig).
- River Road & Juniper Beach Dr. G-610 - 5.6% (MAOP=35 psig).
- River Road & Harbortown Rd. G-621 - 6.7% (MAOP=35 psig).
- River Road & Wolf Pen Branch Rd. – 46.2% (MAOP=50 psig).

Maximum Allowable Operating Pressure
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 250 psig.
IV. River Road Regulator Assemblies (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
- Install approximately 2,800 ft of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 300 ft of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure
- 5300 Juniper Beach Rd – 34.2 psig

Recommended Timeline – 2010-2015

Reinforcement 2
- Uprate River Rd & Woodside Rd medium pressure system from 10 psig to 50 psig.
- Uprate River Rd & Lime Kiln Ln medium pressure system from 20 psig to 50 psig.
- Install approximately 850 ft of 4-inch plastic gas main along Arden Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 1,200 ft of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.
- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.

Minimum Gas System Pressure (-12°F)
- 3950 Kresge Way – 25.03 psig

Recommended Timeline – 2010-2015

Reinforcement 3
- Uprate River Rd & Longview Ave medium pressure system from 10 psig to 35 psig.
- Install approximately 1,200 ft of 2-inch plastic gas main along River Road to connect Longview Ave and Rivers Edge systems.
- Remove the River Rd & Longview Ave regulator assembly.

Minimum Gas System Pressure (-12°F)
- 6120 Longview Ln – 32.69 psig

Regulator Operating Capacity
- River Rd & Rivers Edge Rd – 22.2 %

Recommended Timeline – 2010
River Road Regulator Assemblies – Reinforcement 1

River Creek

Harbortown

Main Extensions

Juniper Beach
River Road Regulator Assemblies – Reinforcement 2

Glenview

Lime Kiln

Woodside

Main Extensions
River Road Regulator Assemblies – Reinforcement 3

Boxhill

Longview

Riverside

Blankenbaker

Main Extension

Knights of Columbus

River’s Edge

Main Extension
V. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview
The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Maximum Allowable Operating Pressure
This medium pressure system has a maximum allowable operating pressure of 35 psig.

Regulator Operating Capacity
- Watterson Tr and Plantside Dr – 66.5%
- Tucker Station Rd & I-64 – 3.2%

Gas System Constraints
Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

Recommended Gas System Reinforcements:
Reinforcement 1
- Install approximately 1,700 feet of 6-inch medium pressure plastic pipeline west from Tucker Station & Lakefront Place, along Tucker Station Road, to the 6-inch pipeline ending on Plantside Drive (near Papa John’s building). This would allow for a multiple feed system, improving system reliability.
- Install approximately 850 ft of 6-inch medium pressure plastic pipeline west from the entrance of the proposed office park, along Tucker Station Road, to the 6-inch main ending east of Sycamore Place.
- Install approximately 1,200 ft of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.

Minimum gas system pressure (-12°F):
- 3025 Element Ln – 30.5 psig
- 2801 Constant Comment Pl – 30.6 psig

Regulator Operating Capacities:
- Tucker Station Rd & I-64 – 21.7%
- Watterson Tr & Plantside Dr – 82.7%

Recommended Timeline: 2010-2015
Plantside Drive Medium Pressure Gas System – Reinforcement 1

Eastern Kentucky Line

Install main on Tucker Station Road

Proposed Business Parks
VI. Bardstown Medium Pressure System

Gas System Overview
The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 3-5 years.

Regulator Facilities
The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

Maximum Allowable Operating Pressure (MAOP)
The Bardstown medium pressure system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 °F)
- 1755 Parkway Dr [39612160]- 24.55 psig

Regulator Operating Capacities
- Bardstown MP – 20.8%
- Chris's Creation MP – 16.5%

Gas System Constraints
Gas system constraints are caused by the lack of a direct gas supply route from the regulator station at the LG&E Bardstown office to the downtown Bardstown area. Due to current and anticipated growth, it will be necessary to reinforce the gas system.

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 1,650 ft of 4-inch plastic pipeline along property lines from Armag Ave to the existing 4-inch plastic on Spencer Mattingly Rd.

Minimum gas system pressure (-12 °F)
- 1755 Parkway Dr – 45.4 psig
VI. **Bardstown Medium Pressure System (cont’d)**

**Regulator Operating Capacities**
- Bardstown MP – 18.9%
- Chris's Creation MP – 32.5%

**Recommended Timeline** – 2010-2012

**Reinforcement 2**
Install approximately 3,500 ft of 4-inch plastic pipeline along Filiatreau Ln and tie into the existing 4-inch plastic main on Glenwood Dr.

**Minimum gas system pressure (-12 °F)**
- 1755 Parkway Dr – 45.7 psig

**Regulator Operating Capacities**
- Bardstown MP – 19%
- Chris's Creation MP – 31.5%

**Recommended Timeline** – TBD
**Note:** This reinforcement should be done in conjunction with the expansion of the Highway 605 industrial park. Results include Flowers Foods Bakery.
VII. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and HiLand
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Hwy 44 and Boardwalk

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on Winding Woods Trail (26.7 psig).
VII. Highway 44 Regulator Assemblies (cont’d)

Regulator Operating Capacities
- Mt Washington MP – 10.4%
- Hwy 44 and Woodlake – 21.4%
- Hwy 44 and Harris – 21.4%
- Hwy 44 and Fisher – 72.9%
- Hwy 44 and Highland Springs – 56.5%
- Hwy 44 and Bethel Church – 20.7%
- Hwy 44 and Azure – 6.9%
- Hwy 44 and Truman – 22.7%
- Hwy 44 and Kennedy – 5.9%
- Hwy 44 and Bogard – 51.7%
- Hwy 44 and Bells Mill – 21%
- Hwy 44 and Alpar – 1.8%
- Hwy 44 and Mockingbird – 47.8%
- Hwy 44 and Sunview – 42.6%
- Hwy 44 and Watergate – 1%
- Hwy 44 and HiLand – 5.2%
- Hwy 44 and Big Clifty – 10%
- Hwy 44 and Halls – 13.4%
- Hwy 44 and Boardwalk – 15.3%

Recommended Gas System Reinforcements

Reinforcement 1
- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 500 feet of 4-inch plastic main along Hwy 44.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,400 ft of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Change the orifice size of Hwy 44 and Halls Ln to ¼”
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)
- 504 Chimney Rock Dr. – 34.4 psig

Regulator Operating Capacities
- Hwy 44 and Halls Ln – 32.6%

Recommended Timeline – 2010-2015
VII. Highway 44 Regulator Assemblies (cont’d)

Reinforcement 2
- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,500 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

Minimum Gas System Pressure (-12°F)
- Douglas Drive – 34.9 psig

Regulator Operating Capacities
- Hwy 44 and Hi-Land – 6.2%

Recommended Timeline – 2010-2015

Reinforcement 3
- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.

Minimum Gas System Pressure (-12°F)
- Old Hickory Lane – 28.3 psig

Regulator Operating Capacities
- Hwy 44 and Sunview – 91.8%

Recommended Timeline – 2010-2015
Note: Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4
- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,100 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

Minimum Gas System Pressure (-12°F)
- 468 East Millwater Falls – 29.04 psig

Regulator Operating Capacities
- Hwy 44 and Bells Mill – 24.3%

Recommended Timeline – 2010-2015
VII. **Highway 44 Regulator Assemblies (cont’d)**

**Reinforcement 5**
- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,300 feet of 6 inch plastic main along Hwy 44.
- Connect Systems served by Bethel Church and Highland Springs facilities with 1,400 feet of 4- or 6-inch plastic main along Hwy 44.
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, and Bethel Church Road facilities.

*Minimum Gas System Pressure (-12°F)*
- Winding Woods Trail – **26.7 psig**

*Regulator Operating Capacities*
- Hwy 44 and Bogard – **44.1%**
- Hwy 44 and Azure – **42.8%**
- Hwy 44 and Highland Springs – **75.9%**

*Recommended Timeline – 2010-2015*

**Reinforcement 6**
- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,900 feet of 6-inch plastic pipe between Harris and Woodlake.
- Convert approximately 34 high-pressure services to medium pressure. **Note:** Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

*Minimum Gas System Pressure (-12°F)*
- Winding Woods Trail – **26.9 psig**

*Regulator Operating Capacities*
- Hwy 44 and Fisher – **65.2%**
- Hwy 44 and Woodlake – **63.8%**

*Recommended Timeline – 2010-2015*
Hwy 44 Regulator Assemblies – Reinforcement 2
Hwy 44 Regulator Assemblies – Reinforcement 4
Hwy 44 Regulator Assemblies – Reinforcement 5
VIII. Hodgenville Medium Pressure System

Gas System Overview
The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

Regulator Facilities
The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

Maximum Allowable Operating Pressure
The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is located at 2017 US Highway 31E (16.4 psig).

Regulator Operating Capacity
- Hodgenville Station – 22.6%

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Hodgenville medium pressure gas distribution system to 50 psig. This uprate will affect approximately 1,091 services and 25.5 miles of pipeline.

Minimum Gas System Pressure (-12°F)

Regulator Operating Capacity
- Highway 84 and Glendale Rd – 22.7%

Recommended Timeline – 2017
IX. Minor Lane Heights Renaissance Zone

Gas System Overview
The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Gas System Reinforcement Completed in 2007
- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 ft of 8-inch plastic main along Outer Loop, Stinnett Ln, proposed Air Commerce Way to serve UPS facility.

Regulator Facilities
The regulator facilities that feed this system are as follows:
- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure
The Minor Lane Heights system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at 2240 Outer Loop (46.1 psig). There is another low pressure point at the south end of Eagle Pass (46.6 psig).

Regulator Operating Capacities
- Preston City Gate Station MP – 52.7%
- Outer Loop and Grade Ln – 47.3%

Gas System Constraints
Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.
IX. Minor Lane Heights Renaissance Zone (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Install and remove gas mains according to “An Analysis of the Minors Lane Heights Renaissance Zone” dated 15 January 2007 or the latest version.

- Retire existing pipelines in the area.
- Install approximately 12,470 ft of 4-inch pipe
- Install approximately 1,975 ft of 6-inch pipe
- Install approximately 4,600 ft of 8-inch pipe

Minimum Gas System Pressure (-12°F)
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) – 53.14 psig

Regulator Operating Capacities
- Preston City Gate Station MP – 52.6%
- Outer Loop and Grade Ln – 54.4%

Recommended Timeline – 2010-2019
Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 1
X. **Mount Washington Medium Pressure System**

**Gas System Overview**  
The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

**Regulator Facilities**  
The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:
- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

**Maximum Allowable Operating Pressure (MAOP)**  
The Mount Washington medium pressure gas system has a maximum allowable operating pressure of 60 psig.

**Model Results**

**Minimum Gas System Pressure (-12°F):**  
The predicted minimum pressure is located on Pin Oak Drive (28.1 psig).

**Regulator Operating Capacities (-12°F):**
- Mt. Washington MP – 10.5%
- Bardstown Rd and Landis Ln – 25.3%

**Gas System Constraints**  
Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

**Recommended Gas System Reinforcements**

**Reinforcement 1**  
Install approximately 3,600 ft of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

**Minimum Gas System Pressure (-12°F):**
- Pin Oak Dr – 49.93 psig

**Regulator Operating Capacities (-12°F):**
- Mt. Washington MP – 8.8%
- Bardstown Rd and Landis Ln – 23.5%
- Vista Hills Blvd and Calvary Line – 100%

*Recommended Timeline – 2011-2015 – This should be done in conjunction with the development of the Oakland Hills subdivision.*
XI. Preston High Pressure Distribution System

Gas System Overview
The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure
The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this high pressure system is located at the inlet to the Preston and Antle regulator pit (68.4 psig)

Regulator Operating Capacities
• Preston City Gate Station – 50.5%

Gas System Constraints
Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Note: The current pressure on the Preston high pressure line prohibits a significant pressure differential across the existing and any new gas regulation facilities. The Preston high pressure pipeline is required to operate very low (75-85 psig) in order to maximize gas withdrawal from the Magnolia compressor station. Operating the Preston high pressure pipeline at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the existing gas regulation facilities.
XII. Penile Gas System Uprate Project

Gas System Overview
The 35 psig system north of the Penile City Gate Station is made up of Third Street Rd, St. Anthony’s Church Rd, Arnoldtown Rd, New Cut Rd, Windsor Forest Subdivision, and other residential and commercial customers. It is bordered to the North by St. Andrews Church Rd, to the South by Pond Creek, to the East by the existing EP system, and to the West by Lakeridge Dr. This uprate includes 97.5 miles of pipe and approximately 8,130 services.

Regulator Facilities
The regulator facilities that supply the gas to the Penile uprate area include:
- St. Andrews Church Road & I.C.R.R.
- New Cut Road & Old 3rd Street Road
- Old 3rd Street Road & Bamberrie Cr.
- Penile City Gate Station medium pressure facility.

Maximum Allowable Operating Pressure
The system has a maximum allowable operating pressure of 35 psig.

Model Results

Gas Regulator Facility Upgrades
- Change the regulation equipment at New Cut Road & Old 3rd Street Road to 3” Mooneys @ 100%.
- Change the regulation equipment at Old 3rd Street Road & Bamberrie Cr. to 3” Mooneys @ 100%.
- Change the set point pressure at Old Third Street Road & Manslick Road to its MAOP of 99 psig.
- Retire the Penile City Gate Station medium pressure gas facility.

Recommended Timeline – 2010

Medium Pressure Gas System Uprate
- Uprate the 35 psig system area to 60 psig and connect it to the existing 60 psig system below.
- Close Valves: 11819094, 12533053, 12332647, 11810152, 12533654, 12304851
- Open Valves: 12333758, 7484120
- Uprate regulators to 60 psig: 11814741, 12564146, 12342053_1, 12443141
Minimum gas system pressure (-12°F):
- 9605 Britannia Ct (33.8 psig)

Regulator Operating Capacities:
- St. Andrews Church Road & I.C.R.R. 10.6%
- New Cut Road. & Old 3rd Street Road 32.5%
- Old 3rd Street Road & Bamberrie Cr. 26%

Recommended Timeline – 2012-2013
XIII. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 °F).
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 °F) with the proposed gas loads and the Mount Washington high pressure system operating at 275 psig.
- Approximately 60-65 Mcf/h of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 56 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.
XIII. Mt. Washington/Lebanon Junction High Pressure Distribution System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

Recommended Timeline – 2012

Reinforcement 2
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.
Mt. Washington High Pressure Distribution System - Overview
Mt. Washington High Pressure Distribution System – Reinforcement 1

- Jim Beam Clermont Plant
- Location of new LG&E regulator facility
- Lebanon Junction
- 8-inch high pressure extension 14.0 miles along Hwy 245
- Jim Beam Boston Plant
- LG&E Calvary Gas Transmission Pipeline
- Publishers Printing

Bellar
XIV. Shepherdsville/Northern Bullitt County Uprate Project

Gas System Overview
The Shepherdsville/Northern Bullitt medium pressure gas system serves residential and commercial customers in Jefferson County and outlying areas between I-64 and I-264.

Regulator Facilities in uprated area
The regulator facilities that supply gas to the Shepherdsville/Northern Bullitt medium pressure system and are located in the uprate area are as follows:

- Regulator pit at Lee’s Lane and Hwy 44
- Regulator pit at Cedar Grove Road and I-65
- Regulator pit at Mud Lane and Antle Drive
- Regulator pit at Old Bardstown Rd and Thixton Ln
- Regulator pit at Vista Hills Blvd and Calvary Line

Maximum Allowable Operating Pressure
The Shepherdsville/Northern Bullitt medium pressure gas system has a maximum allowable operating pressure of 60 psig.

The medium pressure gas distribution system to the north of the 60 psig gas system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)

- 4002 Neagli Court (5.15 psig)
- 11103 Brook Bend Court (6.36 psig)

Regulator Operating Capacities

- Lee’s Lane and Hwy 44 - 20.5%
- Cedar Grove Road and I-65 - 18.6%
- Mud Lane and Antle Drive - 100%
- Old Bardstown Rd and Thixton Ln - 6.6%
- Vista Hills Blvd and Calvary Line - 51%

Gas System Constraints
Gas system constraints in this area are due to low inlet pressures on the Preston high pressure distribution pipeline. This high pressure gas system has a maximum allowable operating pressure of 110 psig. The pressure on the Preston high pressure distribution system is the most problematic during the end of the gas withdrawal season for the Magnolia compressor station.
XIV. Shepherdsville/Northern Bullitt County Uprate Project (cont’d)

Recommended Reinforcement
- Increase the boundaries for the 60 psig system to include the problem areas in the 35 psig system to the north.
- Uprate 153.4 miles of pipeline and approximately 14,675 customers
- Close valves 7458949, 7462206, 7498477, 7499040, 7533181, 7500148, 7514342, 7471363, 7471663
- Open valves 7510213, 7466257, 7466165, 7516765, 14935942, 7508381, 7462477, 7471635, 7471736, 7521689, 7489936, 7489066
- Uprate the regulator station at Preston Hwy and South Park Road to 60 psig.
- Uprate Preston & Springview to 60 psig. Replace the gas regulation equipment with low differential equipment.
- Mud Lane & Antle Drive - Replace the gas regulation equipment with low differential equipment.

Minimum gas system pressure (-12 °F) 60 psig system
- Entire 60psig- Kewana Ct (33.5 psig)
- Entire 60psig- Kendrick Crossing (36.2 psig)

Minimum gas system pressure (-12 °F) 35 psig system
- Inlet to Gardiner Ln & Schuff- (11 psig)
- 3202 Oak Haven Ct- (18.2 psig)

Regulator Operating Capacities
- Lee’s Lane and Hwy 44 - 23.4%
- Cedar Grove Road and I-65 - 20%
- Mud Lane and Antle Drive - 100%
- Old Bardstown Rd and Thixton Ln - 7.1%
- Vista Hills Blvd and Calvary Line - 52.8%
- Preston Hwy and South Park Road - 43.9%
- Preston Hwy and Springview - 51.2%

Recommended Timeline – 2011
Shepherdsville/Northern Bullitt County Uprate Project

Min Press: 40.5 psig
Min Press: 40.9 psig

Preston & Springview
Preston & South Park

Mudd Ln & Antle Dr

= closed valves  = open valves
XV. **Radcliff/Fort Knox Medium Pressure System**

**Gas System Overview**
The Radcliff/Fort Knox medium pressure system serves approximately 4,600 residential and small commercial customers. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/Fort Knox area over the next 8 years.

**Regulator Facilities**
The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W Vine Street.

**Maximum Allowable Operating Pressure**
The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

**Model Results**

**Minimum Gas System Pressure (-12°F)**
The predicted minimum gas system pressure is located at **480 Berkley Ct (32.6 psig).**

**Regulator Operating Capacity (includes asphalt plant load):**
- Radcliff #1: 23.6% (23.6%)
- Radcliff #2: 47% (47%)

**Gas System Constraints**
The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off of St. Andrews Dr will require significant reinforcement.
XV. Radcliff/Fort Knox Medium Pressure System (cont’d)

Recommended Gas System Reinforcement

Reinforcement 1

- Replace existing regulators in Radcliff #2 with 4x3 Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 60 psig.

Note: Additional BRAC load was estimated to be 240 Mcfh based on anticipated number of new residences and current load. This load was proportionately distributed throughout the system.

Minimum gas system pressure (-12°F)

- 1004 Muirfield Ct (32.7 psig)
- 568 St. Andrews Rd (54.33 psig)

Regulator Operating Capacities

- Radcliff #1 – 49.4%
- Radcliff #2 – 14.1%

Recommended Timeline – 2010-2018

Reinforcement 2

- Install 4,800’ of 4-inch plastic main in Otter Creek Rd from existing 4-inch steel main to the 2-inch plastic main in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.
Radcliff/Fort Knox – Reinforcement 1 & 2

Uprate area

Radcliff #1

Radcliff #2

St. Andrews Dr

Reinforcement #2
XVI. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System

Gas System Overview
The Crestwood/Pee Wee Valley/Simpsonville medium-pressure system will require reinforcement to continue to serve the new developments in the area which include professional medical centers, office buildings, and retail/restaurants. This system also supplies the Persimmon Ridge and the Polo Fields developments. The system has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville medium pressure system. There are a few options available that will provide adequate pressures throughout the system.

Gas System Reinforcement Completed in 2007

- Old Henry Road Reinforcement
  - Install 5,700 ft of 8-inch medium pressure pipe north along Old Henry Rd to tie into the 8-inch main at 9207 Ash Land Ct.

Maximum Allowable Operating Pressure
The Crestwood/Pee Wee Valley/Simpsonville medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum gas system pressure (-12°F)
- 1400 Rutland Club Ct – **29.53 psig**

Regulator Operating Capacities
- Hwy 1694 & Worthington Lane – 17.4%
- Old Henry Road & Terra Crossing Blvd. – 51.4%
- Connor Station Road & Colt Run Road – 6.4%
- Crestwood & Old LaGrange Road. G-381 – 30.7%
- Lakeshore Drive. & Old Veechdale Road G13108 – 45.7%
- English Station Way. G-580 – 49.8%
- Westport Road & Murphy Lane. G-456 – 89.8%
- Old LaGrange Road & Collins Lane. G-578 – 22%
XVI. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)

Reinforcement Option 1
This option would require the installation of approximately 5,100 feet of 6-inch medium pressure plastic main along Flat Rock Road between Robin Lane and Curry Branch Road.

.Minimum gas system pressure (-12°F)
- 1400 Rutland Club Ct – 29.6 psig
- 16302 Draw Rein Ct – 29.6 psig

Reinforcement Option 2
This option would require the installation of approximately 8,300 feet of 4-inch medium pressure plastic main along Percy Mill Rd/Johnson Rd beginning at the existing 2-inch main on Percy Mill Rd and ending at the existing 4-inch main on Crosstimbers Dr.

Note: This option would require crossing Floyds Fork.

.Minimum gas system pressure (-12°F)
- 1400 Rutland Club Ct – 32.6 psig
- 16302 Draw Rein Ct – 32.6 psig

Reinforcement Option 3
- Extend 6-inch plastic main on Aiken Rd 13,150 feet to the existing 6-inch main at Flat Rock Rd.
- Install 3,000 feet of 4-inch plastic on Johnson Rd from Aiken Rd. south to Crosstimbers Dr.

Note: This option would require crossing Floyds Fork.

.Minimum gas system pressure (-12°F)
- 10523 Championship Ct. – 36.37 psig
- 5704 Laurel Ln – 36.47 psig

Reinforcement Option 4
- Install 6,600 feet of 8-inch high pressure main along Gilliland Rd from the Eastern KY line north to Shelbyville Rd.
- Install 3,500 feet of 8-inch high pressure main along Shelbyville Rd east to Flat Rock Rd.
- Install 9,000 feet of 8-inch high pressure main from the intersection of Shelbyville Rd and Flat Rock Rd northeast to Polo Fields Ln.
- Install Regulator Station at Polo Fields Ln with a set pressure of 50 psig.

Note: This option would require crossing I-64.

.Minimum gas system pressure (-12°F)
- 10523 Championship Ct. – 36.4 psig
- 5704 Laurel Ln – 36.5 psig
XVI. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)

Reinforcement Option 5
This reinforcement is a combination of reinforcements 1 and 3. It requires the installation of 18,250 feet of 6-inch main and 3,000 feet of 4-inch main. It also requires crossing Floyds Fork.

Minimum gas system pressure (-12 °F)
- 10523 Championship Ct. – 36.4 psig
- 1605 Polo Club Ct. – 19 psig

Reinforcement Option 6
- Perform reinforcement 1
- Install 16,500 feet of 8-inch high pressure along Shelbyville Rd from Conner Station and Colt Run Rd RS to Flat Rock Rd.
- Install 9,000 feet of 8-inch high pressure along Flat Rock Rd to Polo Fields Ln.
- Install a regulator station set at 50 psig that feeds Polo Fields Ln from the new high pressure.

Minimum gas system pressure (-12 °F)
- 2631 Hedgepath Trail – 39.8 psig
- 2102 Polo Creek Ln. – 39.9 psig
Crestwood/Pee Wee Valley/Simpsonville Reinforcement Options 1-6

Note: Option 5 combines Option 1 and Option 3
XVII. East End 20-inch Gas Transmission Pipeline Reinforcement Project

Gas System Overview and Constraints
The concerns for the East side of the gas system stems from the lack of flexibility under design conditions. When the weather is cold, high demand volumes limit how the gas can be delivered. Under design conditions, the East side of the gas system is supplied only by the Texas Gas transmission system and system constrains limit how well other sources would be able to supply that demand.

While the demand distribution percentage between east and west remains consistent based on city gate station supply, the total supply volume increases by a factor of 10 from a 0 HDD to a design day. In warmer weather, the lower total demand gives Gas Control more flexibility in how to transport gas through the system. As the total demand increases, that flexibility decreases due to various infrastructure constraints.

Recommended Gas System Reinforcements

Install a 20-inch pipeline approximately 5.3 miles along Hurstbourne Parkway from the Piccadilly valve assembly to the 12-inch Eastern Kentucky pipeline located at Hurstbourne Lane and Timberwood Circle.

This will enable gas from the Bardstown Road city gate station or from the Calvary pipeline to be moved into the east end gas system. This will also enable storage gas to supplement the area surrounded by the Bardstown Road city gate station. This assumes that pipeline modifications are made to bring a new pipeline from the Magnolia/Muldraugh gas storage areas to the Preston city gate station. This will help eliminate the dependency on the Western Kentucky pipelines (blue, yellow and green) and the St. Helens gas regulation facility.
East End 20-inch Gas Transmission Pipeline Reinforcement Project
XVIII. **New City Gate Station – Oldham County**

**Gas System Overview**
As gas system load growth continues eastward consideration should be given to retire the LaGrange city gate station and construct a new city gate station further east. The LaGrange city gate station is located in a poor location in the bend of Highway 146 adjacent to the railroad.

Recommend installing a new city gate station just north of the intersection of Old Sligo Road and Yager Lane in LaGrange. This station will be supplied by the Texas Gas transmission system.

**Recommended Gas System Reinforcements**

**Reinforcement 1**
- Extend approximately 1.6 miles of 8-inch pipe along Yager Ln and then southwest on Old Sligo Rd.
- Follow N Hwy 53 south with 1.4 miles of 8-inch pipe to Jefferson Street in downtown LaGrange.
- Follow Jefferson Street to the west with 4,000 ft of 8-inch pipe to 710 W Jefferson Street.
- Install a new regulator facility to reduce gas from the new transmission line to 90 psig and connect to the existing 8” high pressure system.
- At the intersection of Old Sligo Rd and Fort Pickens Rd (from the new city gate station) extend the 6-inch main south 2.4 miles along Fort Pickens Rd to the existing 6-inch steel pipeline. Attach pipes with new regulator facility at Fort Pickens Rd and E Highway 146.

  - 4x3 Mooney (35%) for City Gate Station- Utilization: 41%
  - 4x3 Mooney (35%) at 710 W Jefferson St- Utilization: 39.4%
  - 2” Mooney (35%) at Fort Pickens and E Highway 146- Utilization: 32%
  - **Total mileage: 6 miles**

**Reinforcement 2**
- Install a new high pressure regulator facility at Hwy 22 and Old Lagrange Rd in Crestwood.
- From that new facility, extend 4-inch pipe west 3.9 miles along W Hwy 146/LaGrange Rd. Connect to existing 4-inch high pressure.
- This will provide connectivity between the Eastern Kentucky pipeline system and the Crestwood/Ballardsville/LaGrange systems.

  - 2” Mooney (35%) at Hwy 22 and Old LaGrange- Utilization: 35%.
  - **Total mileage: 3.9 miles**
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I. Crestwood-Eminence-Bedford High Pressure Distribution System

Gas System Overview
The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is fed by the Eminence, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Eminence City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

Maximum Allowable Operating Pressure
From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is at 4021 Hwy 146 (198.19 psig).

Regulator Operating Capacities
- Elder Park City Gate Station – 16.0%
- Crestwood City Gate Station – 41.6%
- Bedford City Gate Station – 33%

Note: The reported capacities are with the gas regulation equipment upgrades at the Bedford city gate station (2010) and the Crestwood city gate station (2012).

Gas System Constraints
The system is composed primarily of 4-inch pipeline, limiting the system’s capacity for expansion.
I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Connect the Ballardsville gas transmission line to the Crestwood-Bedford HP system with 5,500 feet of 8” steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22. **NOTE:** Reinforcement done as part of Section II Reinforcement 1.

*Minimum Gas System Pressure (-12°F)*
- 4021 Hwy 146 – 214.2 psig

*Regulator Operating Capacities*
- Elder Park City Gate Station – 16.3%
- Crestwood City Gate Station – 39.3%
- Bedford City Gate Station – 33.1%

Reinforcement 2
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location. If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood–Bedford line should a failure occur.

*Minimum Gas System Pressure (-12°F)*
Inlet to Pleasureville – 68.7 psig

*Regulator Operating Capacities*
Bedford City Gate Station – 73.4%
Crestwood City Gate Station – 57.8%

Reinforcement 3
- Install a new city gate station near L’Esprit Farms at the intersection of E Hwy 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along E Hwy 146 to connect with the Elder Park/Ballardsville Line.
- Install a regulator station where Hwy 146 connects with the Elder Park/Ballardsville Line to lower the pressure to 100 psig from the new city gate station.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).
I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont’d)

Minimum Gas System Pressure (-12°F)
- 4021 Hwy 146 – 259.31 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 15.4%
- Crestwood City Gate Station – 35.0%
- Bedford City Gate Station – 23.9%

Reinforcement 4
- Install a new City Gate Station just north of the intersection of Old Sligo Rd and Yager Ln in LaGrange. This station will be fed from the Texas Gas Transmission Line.
- Extend approximately 1.6 miles of 8-inch pipe along Yager Ln and then southwest on Old Sligo Rd.
- Follow N Hwy 53 south with 1.4 miles of 8-inch pipe to Jefferson Street in downtown LaGrange.
- Follow Jefferson Street to the west with 4,000 feet of 8-inch pipe to 710 W Jefferson Street.
- Install a new regulator facility to reduce gas from the new transmission line to 90 psig and connect to the existing 8” HP.
- At the intersection of Old Sligo Rd and Fort Pickens Rd (from the new city gate station) extend the 6-inch main south 2.4 miles along Fort Pickens Rd to the existing 6-inch steel pipeline. Attach pipes with new regulator facility at Fort Pickens Rd and E Highway 146.
  - 4x3 Mooney (35%) for City Gate Station- Utilization: 41%
  - 4x3 Mooney (35%) at 710 W Jefferson St- Utilization: 39.4%
  - 2” Mooney (35%) at Fort Pickens and E Highway 146- Utilization: 32%
Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 1
Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 3

- Crestwood City Gate Station
- LaGrange City Gate Station
- Elder Park City Gate Station
- New Regulator Facility
- New City Gate Station
- Main Extensions
Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 4

- New City Gate Station
- Main Extensions
- LaGrange City Gate Station
- New Regulator Facilities
- Elder Park City Gate Station
II. East End Gate Stations Gas System Overview

The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure
The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the La Grange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints
If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the Zorn Ave regulator station (258.6 psig).
The predicted minimum gas system pressure on the Crestwood system is located at 4021 Hwy 146 (198.2 psig).
The predicted minimum gas system pressure on the LaGrange system is located at 20 Quality Place (87.2 psig).

Regulator Operating Capacities
- Elder Park City Gate Station – 16.0%
- Crestwood City Gate Station – 41.6%
- LaGrange City Gate Station – 31.1%

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions
- Operate the Elder Park City Gate Station at 300 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig
II. East End Gate Stations Overview (cont’d)

Reinforcement 1
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 7,500 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,800 feet of 8-inch pipeline
  ○ (NOTE: this only helps the systems if the Crestwood facility is shut down.)

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – 315.5 psig
- 4021 Hwy 146 – 243.9 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 15.7%
- Crestwood City Gate Station – 44.9%
- LaGrange City Gate Station – 31.1%

Reinforcement 2
Connect the Elder Park system to the LaGrange system

- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,400 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.
  ○ (NOTE: this only helps the systems if the LaGrange facility is shut down.)

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – 258.8 psig
- Springhouse Estates Inlet – 88.9 psig
- 4021 Hwy 146 – 198.2 psig

Regulator Operating Capacities
- Elder Park City Gate Station – 16.7%
- Crestwood City Gate Station – 41.6%
- LaGrange City Gate Station – 23.3%
II. East End Gate Stations Overview (cont’d)

Reinforcement 3

- Install a new high pressure regulator facility at Hwy 22 and Old Lagrange Rd in Crestwood.
- From that new facility, extend 4-inch pipe west 3.9 miles along W Hwy 146/LaGrange Rd. Connect to existing 4-inch high pressure.

2” Mooney (35%) at Hwy 22 and Old LaGrange- Utilization: 32.3%
East End Gate Stations – Reinforcement 1

- Elder Park City Gate Station
- Hwy 393 Main Extension
- Crestwood City Gate Station
- Hwy 53 Main Extension
East End Gate Stations – Reinforcement 2

LaGrange City Gate Station

Hwy 393 Main Extension

Elder Park City Gate Station

Hwy 146/Fox Run Rd Main Extension
East End Gate Stations – Reinforcement 3

New Facility at Hwy 22 & Old Lagrange
Main Extension
Connect to Eastern Kentucky Line
III. LaGrange Medium Pressure Systems

Gas System Overview
The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure
These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

Minimum Gas System Pressure (-12°F)

<table>
<thead>
<tr>
<th>Sub-System MAOP</th>
<th>Location</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 psig systems</td>
<td>3500 Mattingly Rd [6447519]</td>
<td>7.7 psig</td>
</tr>
<tr>
<td>30 psig system</td>
<td>Parker Pl [6480299]</td>
<td>24.75 psig</td>
</tr>
<tr>
<td>35 psig systems</td>
<td>Kamer Ct [6430958]</td>
<td>29.3 psig</td>
</tr>
</tbody>
</table>

Regulator Operating Capacities:

35 psig Systems
- HOFFMAN LN & PARKVIEW MANOR TBD – 3.6%
- BUTTON CT & COMMERCE PKWY G-21254 – 17.6%
- ALLEN LN & ARTISAN PKWY TBD – 5.7%
- HWY 53 & CHERRY CREEK DR TBD – 52.4%
- NEW CEDAR POINT RD. & OLD LAGRAN G-364 – 51%
- ELDER PARK RD. G-433 – 33.7%
- MOODY LN & HWY 53 G-559 – 22.6%
- E.MOODY LN.& CAL AVE G-593 – 7.4%
- DEER RUN DR G-553 – 13.4%
- GRANGER RD. & HWY.53 G-545 – 27.5%
- PARK RD. & HWY. 53 G-558 – 20%
- ZHALE SMITH RD & HWY 53 G-591 – 9.5%
- SPRINGHOUSE ESTATES SECTION 1 G-599 – 41%
- HWY 146 & FORT PICKENS RD G13112 – 0.06%
- PRESTWICK DR. & HWY. 53 G13115 – 36.7%
- CRYSTAL DR.& GRANGE DR. G18329 – 21.5%
- HWY 146 & I-71 – 16.6%
III. LaGrange Medium Pressure Systems (cont’d)

30 psig systems
- Regulator pit at Woodlawn Ave and Lagrange Rd – 13.7%
- Lagrange medium pressure regulator pit – 56%
- Regulator pit at Hoffman Ln – 55.9%

10 psig systems
- Regulator pit at Hwy 393 & Hwy 146 – 1.2%
- Regulator pit at Kings Ln & Hwy 146 – 1.5%
- Regulator assembly at Georgie Way and Moody Ln – 3.7%
- Regulator assembly at Hazelwood Dr & Elder Park Rd – 13.4%
- Regulator assembly at Sycamore Rd and Elder Park Rd – 25.5%

Gas System Constraints
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

Gas System Reinforcements Note
- Due to economic conditions, these plans have been put on hold for the time being.

Recommended Gas System Reinforcements:

Reinforcement 1
Extend gas mains and uprate LaGrange MP system as described in “An Analysis of the OCEDA Economic Development Campus” dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 MCFH. The proposed reinforcement project requires installing:

- 15,000 feet of 4 inch pipe
- 4,000 feet of 6 inch pipe
- 12,000 feet of 8 inch pipe
- An uprate of 11.6 miles of existing pipeline and 467 existing customers
- A new regulator facility at Moody Lane and North Fible Lane

Minimum gas system pressure (-12°F):
- 2300 Stonybrook Ct – 42.7 psig

Regulator Operating Capacities:
- Moody Ln and North Fible Ln – 15.5%
- Granger Rd and Hwy 53 – 46.6%
- Elder Park Rd – 32.9%
III. LaGrange Medium Pressure Systems (cont’d)

Reinforcement 2
Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in “An Analysis of Proposed Development at Buckner Crossings” dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90MCFH. The proposed reinforcement requires installing:

- 5,100 feet of 6-inch pipe
- 5,300 feet of 4-inch pipe
- 13,100 feet of 2-inch pipe
- Uprate 400 feet of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

Minimum Gas System Pressure (-12°F)
- Southern Patio Home Area – 29.3 psig

Regulator Operating Capacity
- Hwy 393 & Commerce Pkwy – 89.4%
- Commerce Pkwy & Button Court Ln – 18%
LaGrange Medium Pressure Gas System – Reinforcement 1

OCEDA Development Area

New facility at Moody Lane and North Fible

Moody Lane

HWY 53
LaGrange Medium Pressure Gas System – Reinforcement 2

Button Court Ln

Hwy 393 & Hwy 146

Buckner Crossing Development Area

New Regulator Pit at Hwy 393 & Commerce Pkwy
IV. Prospect Medium Pressure System

The system surrounding Hwy 1793 in Oldham County needs piping reinforcement. Due to long stretches of small diameter piping the area along Belknap Beach Road and River Glen Lane is suffering. The system is fed by two regulator facilities off of Hwy 42 set at 35 psig and the minimum pressure at these points is 19 psig. Located just 250 feet away is a 20 psig system, fed by the Riverbluff Farms facility on Hwy 42, which supplies the River Glen area. It is recommended that these 2 systems are tied together to reinforce the system and reduce consequence from an emergency.

Minimum Gas System Pressure (-12°F)
Louisville Yacht Club- **19.3 psig**
14462 River Glades Drive- **19.6 psig**

Regulator Operating Capacities
- Riverbluff Farms & Hwy 42 – **8.4%**
- Hwy 42 & Hwy 1793 – **43.6%**
- Hwy 42 & Barbizon Place – **6.2%**

**Recommended Gas System Reinforcements:**

Reinforcement 1
Install new pipe to connect the two systems.

- Uprate the Riverbluff Farms system to 35 psig
- Install 1500’ of 4-inch pipe to connect the existing 4-inch on River Glades Dr to the existing 4-inch on S Rose Island Rd.

Minimum Gas System Pressure (-12°F)
Louisville Yacht Club- **29.8 psig**
14462 River Glades Drive- **32.0 psig**

Regulator Operating Capacities
- Riverbluff Farms & Hwy 42 – **19.0%**
- Hwy 42 & Hwy 1793 – **34.0%**
- Hwy 42 & Barbizon Place – **5.1%**
Prospect Medium Pressure System

Hwy 42 & Barbizon

Hwy 42 & 1793

Riverbluff & 42
V. **Windsor Forest 35 psig Medium Pressure System**

The Windsor Forest area of the west end system has experience lower minimum pressures since the retirement of the Preston City Gate medium pressure facility. It is bordered by Pond Creek to the south and is just a natural ending point for all flows of gas in that system. There are currently plans to install a medium pressure facility and Old 3rd & Manslick to feed this system.

**Existing Model Results**

Minimum Gas System Pressure (-12°F)
- Britannia Court- **9.6 psig**
- Twin Lakes Court- **10 psig**

Regulator Operating Capacities
- Dixie Hwy & East Pages Ln – **55.3%**
- St. Andrews Church Rd & ICRR – **48.0%**
- Old 3rd St. Rd. & Bamberrie Cr – **24.2%**
- New Cut Rd & Old 3rd Street Rd- **21.0%**

**Recommended Reinforcements:**

Reinforcement 1

- (Already Planned) Install a 2” Mooney assembly from the 12-inch high pressure distribution piping along Manslick Rd. Install 100 feet of 8-inch inlet piping and 100 feet of 4-inch outlet piping.
- Install approximately 230 feet of 4-inch pipe on Arnoldtown Road just north of Windsor Lakes Pkwy.

Minimum Gas System Pressure (-12°F)
- Britannia Court- **17.4 psig**
- Twin Lakes Court- **18.7 psig**

Regulator Operating Capacities
- Dixie Hwy & East Pages Ln – **53.8%**
- St. Andrews Church Rd & ICRR – **48.1%**
- Old 3rd St. Rd. & Bamberrie Cr – **19.6%**
- New Cut Rd & Old 3rd Street Rd- **15.2%**
- New Station at Old 3rd & Manslick- **39.1%**
VI. River Road/Highway 42 Regulator Assemblies

Gas System Overview
Gas System Planning has identified eleven regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park Line.

Gas System Reinforcement Completed
As part of the Farm Tap upgrade project, several medium pressure reinforcements were made, resulting in the removal of two River Road Assemblies. The reinforcements are:

- The Jeffersontown system was uprated to 50 psig MAOP in 2008 which uprated the Blankenbaker, Glenview, and Lime Kiln facilities.

Regulator Facilities
The regulator facilities in these areas are as follows:

- RIVER RD. & WOODSIDE RD. G-623 16.5%
- RIVER RD. & BOX HILL LN. G-515 12.5%
- RIVER RD. & LIME KILN LN. G-624 11.5%
- BLANKENBAKER L.N. & RIVER RD. G-335 10.7%
- RIVER RD & GLENVIEW G-329 6.4%
- RIVER RD. & RIVERS EDGE SUB. G-600 20.6%
- RIVER RD.PIT SER RIVERCREEK G-590 22.4%
- RIVER RD. & JUNIPER BEACH DR. G-610 5.2%
- RIVER RD. &HARBOR TOWN RD. G-621 6.4%
- RIVER BLUFF FARMS & HWY. 42 G-339 8.4%
- RIVER RD. & DUROC ACE. G-579 6.8%
- HUNTING CREEK G-328 22.0%
- COVERED BRIDGE & WOODBRIDGE G-1898 3.0%
- COVERED BRIDGE RD & COVERED COVE G-584 1.1%
- MELROSE RETAIL G-19321 1.9%
- HWY. 42 & HUNTERS RIDGE DR. G-607 15.5%
- HWY. 42 & HAYFIELD WAY G18755 10.9%
- HIGH MEADOWS PIKE G-543 13.6%
- HWY. 42 & HILLCREST SUB. G-612 12.4%

Maximum Allowable Operating Pressure
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 300 psig.

The Lime Kiln Ln, Glenview, and Woodside Rd system has a maximum allowable operating pressure of 50 psig.

All other systems have a maximum allowable operating pressure of 35 psig.
VI. River Road/ Hwy 42 Regulator Assemblies (cont’d)

The Ballardsville Line contains many regulators with subsystems that could be combined for better flow and less maintenance. The Glenview and Indian Hills areas of Jefferson County along River Road contain five facilities that could be retired. The Blankenbaker Ln, Lime Kiln Ln, Glenview, and Woodside Rd systems have a maximum allowable operating pressure of 50 psig. The River’s Edge Rd, Juniper Beach Dr, Harbortown Rd, and Rivercreek Dr, and Box Hill Ln systems have a maximum allowable operating pressure of 35 psig.

Recommended Gas System Reinforcements

Reinforcement 1
- Install approximately 2,800 feet of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 300 feet of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure (-12°F)
- 5301 Juniper Beach Rd – 34.2 psig

Regulator Facility Utilization (-12°F)
- River Rd. Pit serving Rivercreek – 34%

Reinforcement 2
- Install approximately 850 feet of 4-inch plastic gas main along Arden Rd and 540 feet of 2-inch plastic gas main on Glenview Ave at Orion Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 2500 feet of 4-inch plastic gas main along River Rd and 1,200 feet of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.
- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Wolfpen Ridge Ct – 27.3 psig
- Phoenix Hill Dr- 34.3 psig

Regulator Facility Utilization (-12°F)
- River Rd. & Glenview – 9.8%
VI. River Road/ Hwy 42 Regulator Assemblies (cont’d)

Reinforcement 3
- Uprate the Rivers Edge and Box Hill Ln systems to 50 psig.
- Install approximately 800 feet of 2-inch plastic gas main along Longview Ln to connect Longview Ave to the Box Hill Ln system.
- Install approximately 1450 feet of 2-inch plastic gas main along River Rd to connect the Woodside Rd and Box Hill Ln systems.
- Install approximately 1200 feet of 4-inch plastic gas main on River Rd to connect the Blankenbaker and Rivers Edge systems.
- Retire the River Rd & Rivers Edge facility

Minimum Gas System Pressure (-12°F)
- Phoenix Hill Drive – 34.4 psig
- Cedar Ridge Court- 32.7 psig

Regulator Operating Capacity
- River Rd & Box Hill Ln – 39.5 %
- Blankenbaker & River Rd 11.8%

Reinforcement 4
- Install 900 feet of 4-inch pipe along Hwy 42 from Hunting Creek Drive to Covered Bridge Rd and 2200 feet of 4-inch pipe from Hwy 42 to the Covered Bridge regulator facility.
- Retire the Covered Bridge & Woodbridge facility and the Covered Bridge & Covered Cove facility.

Minimum Gas System Pressure (-12°F)
- Beachland Beach Road – 26.6 psig
- Talahi Way- 34.7 psig

Regulator Operating Capacity
- River Rd & Duroc Ave – 6.8 %
- Hunting Creek- 21.9%
- Hwy 42 & Hayfield- 4.3%
VI. River Road/ Hwy 42 Regulator Assemblies (cont’d)

Reinforcement 5
- Install 3600 feet of 4-inch pipe along Hwy 42 from the existing 4-inch pipe just west of Hayfield Way to the Melrose Retail facility, connecting it to the Hwy 42 & Hayfield Way, Riverbluff Farms & Hwy 42, Hwy 42 & Hunters Ridge Rd, and Melrose Retail facilities.
- Install 130’ of 2-inch plastic on Ridgemoor Drive to cross Hwy 42 and connect the subsystems.
- Retire the Riverbluff Farms & Hwy 42, Hwy 42 & Hunters Ridge Rd, Melrose Retail facilities, and High Meadows Pike facilities.

Minimum Gas System Pressure (-12°F)
- Beachland Beach Road – 26.6psig
- Deercross Drive- 32.0 psig

Regulator Operating Capacity
- Highway 42 & Hayfield – 10.9 %
- Hwy. 42 & Hillcrest Sub. 12.4%
- River Rd. & Duroc Ave- 6.8%
- Hunting Creek- 22.1%
River Road Regulator Assemblies – Reinforcement 1

Harbortown

Main Extensions

River Creek

Juniper Beach
River Road Regulator Assemblies – Reinforcement 2

Glenview

Lime Kiln

Woodside

Main Extensions
River Road Regulator Assemblies – Reinforcement 3

Woodside

Boxhill

Blankenbaker

River’s Edge

Main Extension

Main Extension
VII. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview
The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Maximum Allowable Operating Pressure
This medium pressure system has a maximum allowable operating pressure of 35 psig.

Regulator Operating Capacity
- Watterson Tr and Plantside Dr – 40.9%
- Tucker Station Rd & I-64 – 2.7%

Gas System Constraints
Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

Recommended Gas System Reinforcements:
Reinforcement 1
- Install approximately 1,200 feet of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.
- Install approximately 2,400 feet of 6-inch medium pressure plastic pipeline west from the existing 4-inch main at Tucker Station and Sycamore Station to 12711 S Pope Lick Rd. This would feed the proposed businesses expected to fill the area.

Minimum gas system pressure (-12°F):
- 10315 Watterson Trail – 24.1 psig
- Sycamore Station Place – 30.0 psig

Regulator Operating Capacities:
- Tucker Station Rd & I-64 – 20.5%
- Watterson Tr & Plantside Dr – 45.0%

Recommended Timeline:
Note: This reinforcement should be completed after the Kentucky Department of Transportation widens Tucker Station Road and Pope Lick Road.
Plantside Drive Medium Pressure Gas System – Reinforcement 1

Eastern Kentucky Line

Install main on Tucker Station Road

Proposed Business Parks
VIII. Jeffersontown/Fern Creek Medium Pressure System

Gas System Overview
The Jeffersontown and Fern Creek areas are part of a large medium pressure gas system that serves the southeastern part of Jefferson County. This system is composed of rural, residential, and small commercial customers and has continued to experience rapid growth in these sectors. The majority of Jeffersontown and Fern Creek areas are served from the following regulator facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator pit at Taylorsville Road and Hopewell Road (Jeffersontown Pit)
- Regulator assembly at Gentry Lane and the Calvary Line
- Regulator pit at Cedar Creek Road and the Calvary Line
- Regulator station at Hudson Lane

Maximum Allowable Operating Pressure
The Jeffersontown/Fern Creek medium pressure gas system has a maximum allowable operating pressure of 55 psig.

Model Results

Minimum Gas System Pressures (-12 °F)
- 11708 Kewana Ct – 21.66 psig

Regulator Operating Capacity
Cedar Creek & Calvary- 15.4%
Cedar Grove & I-65- 31.1%
Hudson Ln. Station- 73.8%
Hwy 44 & Lees Ln- 22.9%
Jeffersontown Pit- 15.5%
Mud Ln & Antle Dr- 100%
Old Bardstown & Thixton- 9.8%
Outer Loop & Grade Ln- 40.4%
Preston Hwy & Springview- 59.3%
Preston Hwy & South Park- 39.7%
Vista Hills & Calvary Line- 64.3%

Gas System Constraints
Gas system constraints in this area are primarily due to the infrastructure of small diameter piping coming from the sources as well as isolated areas. Due to current and anticipated growth it will be necessary to perform gas system reinforcement work.
VIII. Jeffersontown/Fern Creek Medium Pressure System (cont’d)

Recommended Gas System Reinforcement

Reinforcement 1
Upate the Bluegrass Industrial Park to 55 PSIG and connect to the Jeffersontown 60psig system

- Close valves 372425, 372411 and 372374
- Uprate the Watterson Trail & Plantside Dr and Tucker Station Rd. & Betty Ray Ln facilities to 55psig.
- Open valves 121:02, 372376, and 372434

Minimum gas system pressure (-12°F)
- 11708 Kewana Ct – 33.6 psig

Regulator Operating Capacity
- Cedar Creek & Calvary- 14.3%
- Cedar Grove & I-65- 30.7%
- Hudson Ln. Station- 68.1%
- Hwy 44 & Lees Ln- 22.7%
- Jeffersontown Pit- 15.6%
- Mud Ln & Antle Dr- 100%
- Old Bardstown & Thixton- 9.6%
- Outer Loop & Grade Ln- 39.9%
- Preston Hwy & Springview- 57.9%
- Preston Hwy & South Park- 38.7%
- Vista Hills & Calvary Line- 63.6%
Jeffersontown/Fern Creek Medium Pressure System- Reinforcement

Tucker Station & Betty Ray facility

Watterson Tr. & Plantside facility

Valves 372425, 372411, 372374

Valves 121:02, 372376, 372434
**IX. Bardstown Medium Pressure System**

**Gas System Overview**
The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 2-3 years.

**Gas System Reinforcements completed in 2012**
Approximately 1,300 feet of 4-inch pipe was installed to connect the gap from Armag Ave to Spencer Mattingly Road.

**Regulator Facilities**
The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

**Maximum Allowable Operating Pressure (MAOP)**
The Bardstown medium pressure system has a maximum allowable operating pressure of 55 psig.

**Model Results**

**Minimum Gas System Pressure (-12 °F)**
- 1755 Parkway Drive- 41.33 psig

**Regulator Operating Capacities**
- Bardstown MP – 26.5%
- Hwy 245 & Calvary – 45.8%
Bardstown Medium Pressure Gas System
X. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and Hi-Land
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Board Walk Ave & Hwy 44

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on Winding Woods Trail (27.4 psig).
X. Highway 44 Regulator Assemblies (cont’d)

Regulator Operating Capacities
- Mt Washington MP – 11.8%
- Hwy 44 and Woodlake – 22.8%
- Hwy 44 and Harris – 23.0%
- Hwy 44 and Fisher – 79.4%
- Hwy 44 and Highland Springs – 63.7%
- Hwy 44 and Bethel Church – 23.2%
- Hwy 44 and Azure – 7.8%
- Hwy 44 and Truman – 26.8%
- Hwy 44 and Kennedy – 6.8%
- Hwy 44 and Bogard – 1.9%
- Hwy 44 and Bells Mill – 25.9%
- Hwy 44 and Alpar – 2.2%
- Hwy 44 and Mockingbird – 57.9%
- Hwy 44 and Sunview – 53.1%
- Hwy 44 and Watergate – 1.3%
- Hwy 44 and HiLand – 6.5%
- Hwy 44 and Big Clifty – 13.8%
- Hwy 44 and Halls – 18.3%
- Hwy 44 and Boardwalk – 20.1%

Recommended Gas System Reinforcements

Reinforcement 1
- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 600 feet of 4-inch plastic main along Hwy 44 and Halls Ln.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,100 feet of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Change the orifice size of Hwy 44 and Halls Ln to ¼”
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Tanager Lane – 34.3 psig

Regulator Operating Capacities
- Hwy 44 and Halls Ln – 43.3%
X. Highway 44 Regulator Assemblies (cont’d)

Reinforcement 2
- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,500 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

Minimum Gas System Pressure (-12°F)
- Douglas Drive – 34.9 psig

Regulator Operating Capacities
- Hwy 44 and Hi-Land– 7.9 %

Reinforcement 3
- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.
- Change the orifice size of Hwy 44 & Sunview to 3/8”.

Minimum Gas System Pressure (-12°F)
- Old Hickory Lane – 28.7 psig

Regulator Operating Capacities
- Hwy 44 and Sunview – 53.1%

Note: Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4
- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,100 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

Minimum Gas System Pressure (-12°F)
- 468 East Millwater Falls – 29.6 psig

Regulator Operating Capacities
- Hwy 44 and Bells Mill – 29.4%
X. Highway 44 Regulator Assemblies (cont’d)

Reinforcement 5
- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,300 feet of 6 inch plastic main along Hwy 44.
- Connect systems served by Hwy 44 & Azure and Hwy 44 & Bethel Church with 1,950 feet of 4-inch plastic pipe along Hwy 44.
- Connect systems served by Bethel Church and Highland Springs facilities with 1,400 feet of 4- or 6-inch plastic main along Hwy 44.
- Change the orifice size of Hwy 44 & Azure to 3/8”
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, Azure, and Bethel Church Road facilities.

Minimum Gas System Pressure (-12°F)
- Winding Woods Trail – 29.6 psig

Regulator Operating Capacities
- Hwy 44 and Bells Mill Rd – 30.9%
- Hwy 44 and Bogard– 30.7%
- Hwy 44 and Highland Springs – 91.6%
- Hwy 44 and Fisher Ln – 80.3%

Reinforcement 6
- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,000 feet of 6-inch plastic pipe between Harris and Woodlake from Half Moon Drive to Woodlake Drive.
- Convert approximately 34 high-pressure services to medium pressure.
  Note: Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

Minimum Gas System Pressure (-12°F)
- Winding Woods Trail – 27.4 psig

Regulator Operating Capacities
- Hwy 44 and Fisher – 78.9%
- Hwy 44 and Woodlake – 47.9%
Hwy 44 Regulator Assemblies – Reinforcement 1

- 4-inch Main Extensions
- Board Walk
- Big Clifty
- Hwy 44 and Halls Ln Regulator Assembly
Hwy 44 Regulator Assemblies – Reinforcement 4

Bells Mill

Main Extension
Hwy 44 Regulator Assemblies – Reinforcement 5

Main Extension

Highland Springs

HWY 44

Bells Mill

Bogard

Kennedy

Azure

Bethel Church
Hwy 44 Regulator Assemblies – Reinforcement 6

Main Extension

Fisher

Woodlake

Mt. Washington MP Station

Harris
XI. Hodgenville Medium Pressure System

Gas System Overview
The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

Regulator Facilities
The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

Maximum Allowable Operating Pressure
The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is located at 2017 US Highway 31E (16.7 psig).

Regulator Operating Capacity
- Hodgenville Station – 22.6%

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Hodgenville medium pressure gas distribution system to 45psig. This uprate will affect approximately 1,091 services and 25.5 miles of pipeline.

Minimum Gas System Pressure (-12°F)
- 2017 US Highway 31E – 43.2 psig

Regulator Operating Capacity
- Hodgenville Station – 20.6%
XII. Waste Management Relocation Project

Gas System Overview
The Penile City Gate Station supplies gas to the Preston City Gate Station via a 20-inch transmission pipeline (the Penile to Preston Line). The Penile to Preston Line crosses Waste Management landfill property from the Outer Loop to I-65. The two primary feeds associated with this pipeline are from the Penile and Preston City Gate Stations. Due to planned construction at the landfill, approximately 6,000 feet of the Penile to Preston Line that run through the landfill property must be relocated.

Maximum Allowable Operating Pressure
The Penile to Preston Line has a maximum allowable operating pressure of 420 psig.

Recommended Relocation
Shift the portion of the pipeline that runs through landfill property approximately 500 feet to the southeast. The pipeline should roughly run along an access road in the landfill and should reconnect with the existing pipeline before it crosses underneath I-65. This relocation will require approximately 6,600 feet of 20-inch high-pressure pipeline.
XIII. Minor Lane Heights Renaissance Zone

Gas System Overview
The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Gas System Reinforcement Completed in 2007
- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 feet of 8-inch plastic main along Outer Loop, Stinnett Ln, and proposed Air Commerce Way to serve UPS facility.

Regulator Facilities
The regulator facilities that feed this system are as follows:
- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure
The Minor Lane Heights system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at **2240 Outer Loop (46.1 psig)**. There is another low pressure point at the south end of Eagle Pass (46.6 psig).

Regulator Operating Capacities
- Preston City Gate Station MP – **52.7%**
- Outer Loop and Grade Ln – **47.3%**

Gas System Constraints
Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.
XIII. Minor Lane Heights Renaissance Zone (cont’d)

Recommended Gas System Reinforcements

Reinforcement 1
Install and remove gas mains according to “An Analysis of the Minors Lane Heights Renaissance Zone” dated 15 January 2007 or the latest version.

- Retire existing pipelines in the area.
- Install approximately 1,200 feet of 2-inch pipe
- Install approximately 15,400 feet of 4-inch pipe
- Install approximately 5,600 feet of 8-inch pipe

Minimum Gas System Pressure (-12°F)
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) – 32.3 psig

Regulator Operating Capacities
- Preston City Gate Station MP – 53.1%
- Outer Loop and Grade Ln – 41.5%
Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 1
XIV. Mount Washington Medium Pressure System

Gas System Overview
The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

Regulator Facilities
The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:

- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

Maximum Allowable Operating Pressure (MAOP)
The Mount Washington medium pressure gas system has a maximum allowable operating pressure of 60 psig and is set at 55 psig.

Model Results

Minimum Gas System Pressure (-12 °F):
The predicted minimum pressure is located on Pin Oak Drive (22.7 psig).

Regulator Operating Capacities (-12 °F):

- Mt. Washington MP – 11.8%
- Bardstown Rd and Landis Ln – 28.2%

Gas System Constraints
Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 5,900 feet of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

Minimum Gas System Pressure (-12 °F)

- Pin Oak Dr – 45.3 psig

Regulator Operating Capacities (-12 °F):

- Mt. Washington MP – 9.7%
- Bardstown Rd and Landis Ln – 26.0%
- Vista Hills Blvd and Calvary Line – 100%
Mount Washington Medium Pressure System – Reinforcement 1

- Vista Hills & Calvary
- Main Extension
- Bardstown & Landis
- Mt. Washington MP
XV. Preston High Pressure Distribution Pipeline Reinforcement

Gas System Overview
The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure
The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this high pressure system is located at the inlet to the Preston and Antle regulator pit (51.3 psig)

Regulator Operating Capacities
- Preston City Gate Station – 28.6%

Gas System Constraints
Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
The State Highway Department plans on completing a corridor alignment along Cooper Chapel Road, in the City of Okolona.

- Install approximately 37,490 feet of 12-inch high pressure gas pipeline from the Calvary line at Old Bardstown & Thixton to the Preston high pressure line.
- Install a new regulator facility (4x3 Mooney assemblies with 100% plates) at Preston Highway and Cooper Chapel Road to reduce the pressure from the Calvary Line to 110 psig.

Minimum Gas System Pressure (-12°F)
- Preston and Antle inlet – 87.5 psig

Regulator Operating Capacities
- New facility at Cooper Chapel and Preston Highway – 61.3%
XV. Preston High Pressure Distribution Pipeline Reinforcement (cont’d)

Eventually, the pipeline would be extended further south along Preston Highway and this would allow a second feed for the high pressure system (see Section XIX). Without the second feed, if the Preston high pressure pipeline was damaged, the areas of Okolona and Maryville and a portion of Shepherdsville would be lost.

Reinforcement 2

• Extend the 8-inch steel high-pressure main south along Preston Highway from Mud Lane to Bells Mill Road (approx. 20,000 feet).
• Install a medium pressure regulator facility at Bells Mill Road and Preston Highway (4x3 Mooney with 100% plates) to be tied into the 8-inch medium pressure main on Preston Highway or Bells Mill Road.

Minimum Gas System Pressure (-12°F)

• Inlet to new Facility at Preston & Bells Mill – 70.1 psig

Regulator Operating Capacities

• Cooper Chapel and Preston – 70.6%
• Mud and Antle – 28.6%
• Preston and Bells Mill – 51.5%

Note: The current pressure on the Preston HP line prohibits a significant pressure differential across the new regulator assembly. The results shown are after Reinforcement 1 has been completed. Operating the Preston HP line at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the new assembly.
Preston Highway High Pressure Pipeline – Reinforcement 1

- Cooper Chapel Road
- Independence School Road
- New Regulator Facility
- New 12” high-pressure line
- I-265

Attachment to Response to AG-1 Question No. 440(e)

Page 296 of 356

Bellar
XVI. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 °F).
- Due to the reduction in the contract from Tennessee Gas at Calvary in 2012, the Mount Washington high pressure facility is drooping with an inlet pressure of 261 psig.
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 °F) with the existing loads for 2013 and the Mount Washington high pressure system operating at 275 psig.
- LG&E cannot meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 °F) with the proposed gas loads and the Mount Washington high pressure system operating at 275 psig.
- Approximately 45 MCFH of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 55 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.
- LG&E can meet gas load projections until 2016 with a 2% residential and commercial load growth projection and the Shepherdsville gas distribution system
uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2016.

- LG&E can meet gas load projections until 2012 with a 4% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2012.
LG&E can meet gas load projections until 2011 with a 5% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2011.

**Recommended Gas System Reinforcements**

**Reinforcement 1**
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

**Recommended Timeline – 2016**

**Note:** For further information regarding proposed reinforcements to this system, see Section XXII.

**THIS IS NOT AN OPTION AT CALVARY’S CURRENT CONTRACT AMOUNT.**
Mt. Washington High Pressure Distribution System – Reinforcement 1

Jim Beam Clermont

New regulator facility

8-inch high pressure extension

Publishers Printing

Jim Beam Boston

Bardstown
XVII. Brandenburg High Pressure System

Gas System Overview
The Brandenburg high-pressure distribution system serves the cities of Brandenburg and Doe Valley, and the surrounding area. Gas is supplied from Doe Run storage field lines at Riggs Junction. The Brandenburg area continues to experience residential and commercial growth.

Note: The pipeline in this system may be in poor condition. Field data collected during the 2002/2003 heating season indicated pressure loss higher than predicted from the system model. This may be due to water intrusion and iron sulfide in the pipeline. Further data should be collected to monitor the condition of this pipeline.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is at the inlet of the regulator pit serving the Brandenburg medium-pressure system located at Old US 60 and Highway 933 (133.0 psig).

Area Reinforcements

The Brandenburg high-pressure distribution system is comprised of 4.3 miles of 4-inch pipeline that would need to be reinforced or replaced to support future growth. It is recommended to either loop the 4.3 miles of 4 inch high pressure pipe or replace it with 8-inch pipe.
**XVIII. Radcliff/Fort Knox Medium Pressure System**

**Gas System Overview**
The Radcliff/Fort Knox medium pressure system serves approximately 4,600 residential and small commercial customers. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/Fort Knox area over the next 8 years.

**Regulator Facilities**
The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W Vine Street.

**Maximum Allowable Operating Pressure**
The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

**Model Results**

**Minimum Gas System Pressure (-12°F)**
The predicted minimum gas system pressure is located at **480 Berkley Ct (32.8 psig)** and **569 St. Andrews Dr (33.0 psig)**

**Regulator Operating Capacity (includes asphalt plant load):**
- Radcliff #1: 23.1%
- Radcliff #2: 47.5%

**Gas System Constraints**
The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off St. Andrews Dr will require significant reinforcement.
XVIII. Radcliff/Fort Knox Medium Pressure System (cont’d)

Recommended Gas System Reinforcement

Reinforcement 1
- Replace existing regulators in Radcliff #2 with 2” Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 55 psig.

Note: Additional BRAC load was estimated to be 240 MCFH based on anticipated number of new residences and current load. This load was proportionately distributed throughout the system.

Minimum gas system pressure (-12°F)
- 480 Berkley Ct (50.2 psig)
- 568 St. Andrews Rd (50.7 psig)

Regulator Operating Capacities
- Radcliff #1 – 47.8%
- Radcliff #2 – 43.6%

Reinforcement 2
- Install 4,800’ of 4-inch PL main in Otter Creek Rd from existing 4-inch CT to 2-inch PL in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.
**XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System**

**Gas System Overview**
The Crestwood/Pee Wee Valley/Simpsonville medium-pressure system will require reinforcement to continue to serve the Norton Commons development and the Old Brownsboro Crossing commercial park, which includes a professional medical center, office buildings, and retail/restaurants. This system also feeds near Persimmon Ridge and the Polo Fields. It has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System. There are a few options available that will provide adequate pressures throughout the system.

**Maximum Allowable Operating Pressure**
The Crestwood/Pee Wee Valley/Simpsonville medium pressure system has a maximum allowable operating pressure of 45 psig.

**Model Results**

*Minimum gas system pressure (-12°F)*
- 1400 Rutland Club Ct – **22.3 psig**
- 18521 Bridgemore – **24.3 psig**
- 10523 Championship Court- **31.4 psig**

*Regulator Operating Capacities*
- Hwy 1694 & Worthington – 14.6%
- Old Henry & Terra Crossing – 47.1%
- Conner Station & Colt Run – 6.0%
- Crestwood & Old LaGrange – 30.4%
- Lakeshore Drive & Old Veechdale – 40.6%
- English Station Way – 46.5%
- Westport Road & Murphy Lane – 76.8%
- Old LaGrange Road & Collins Lane G-578 – 14.3%
XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)

Reinforcement Option 1
Extend the 8” high pressure gas main on Aiken Road and install a facility at Aiken Road and Flat Rock Road

- Install approximately 3 miles of 8-inch steel high pressure main along Aiken Road from the existing 8-inch on Old Henry Road to Flat Rock Road.
- Install a 4x3 Mooney assembly (35%) at Aiken and Flat Rock to feed the medium pressure system.

Minimum gas system pressure (-12 °F)
- 1400 Rutland Club Ct – 36.6 psig
- 18521 Bridgemore– 34.5 psig
- 10523 Championship Court- 31.4 psig

Regulator Operating Capacities
- New Facility @ Aiken & Flat Rock- 30.5%

NOTE: This would require crossing Floyd’s Fork

Reinforcement Option 2a
Extend the 4” high pressure gas main on Abbott Lane and install a facility at Aiken Road and Floydsburg Road.

- Install approximately 3 miles of 4-inch steel high pressure pipe along Aiken Road from the existing 4-inch on Abbott Lane along State Hwy 1818 and Floydsburg Road to Aiken Road.
- Install a 2” Mooney assembly (35%) at Aiken Road and Floydsburg Road to feed the medium pressure system.

Minimum gas system pressure (-12 °F)
- 1400 Rutland Club Ct – 32.8 psig
- 18521 Bridgemore– 31.4 psig
- 10523 Championship Court- 31.4 psig

Regulator Operating Capacities
- New Facility @ Aiken & Floydsburg- 28.5%

NOTE: This would require crossing Floyd’s Fork
XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)

Reinforcement Option 2b
- Complete Reinforcement 2a.
- Install 1.3 miles of 4-inch plastic medium pressure pipe along Johnson Road and Aiken Road from Crosstimbers Drive to Flat Rock Road.

Minimum gas system pressure (-12 °F)
- 1400 Rutland Club Ct – **35.5 psig**
- 18521 Bridgemore – **31.4 psig**
- 10523 Championship Court - **31.4 psig**

NOTE: This would require crossing Floyd’s Fork

Reinforcement Option 2c
- Complete Reinforcement 2a and 2b.
- Install approximately 1 mile of 6-inch plastic pipe along Flat Rock Road from Curry Branch Road to Long Run Park Road.
- Install approximately 1200 feet of 4-inch plastic pipe along Moser Farm Road beginning at Hitt Lane and ending at the existing 4-inch pipe on Moser Farm Road.

Minimum gas system pressure (-12 °F)
- 1400 Rutland Club Ct – **35.7 psig**
- 18521 Bridgemore – **34.4 psig**
- 10523 Championship Court - **36.2 psig**

NOTE: This would require crossing Floyd’s Fork

Reinforcement Option 3a
- Install approximately 1 mile of 6-inch plastic pipe along Flat Rock Road from Curry Branch Road to Long Run Park Road.
- Install approximately 1200 feet of 4-inch plastic pipe along Moser Farm Road beginning at Hitt Lane and ending at the existing 4-inch pipe on Moser Farm Road.
- Install 1.3 miles of 4-inch plastic medium pressure pipe along Johnson Road and Aiken Road from Crosstimbers Drive to Flat Rock Road.
- Install approximately 3,000 feet of 4-inch pipe along Bridgemore Lane from the existing 2-inch pipe south to connect at Shelbyville Road.
XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont’d)

Minimum gas system pressure (-12 °F)
- 1400 Rutland Club Ct – **25.4 psig**
- 18521 Bridgemore– **34.8 psig**
- 10523 Championship Court- **36.1 psig**

Reinforcement Option 3b
- Complete Reinforcement 3a
- Install approximately 1.6 miles of 6-inch main along Aiken Road from the existing 6-inch at Arnold Palmer Blvd to Johnson Road.

Minimum gas system pressure (-12 °F)
- 1400 Rutland Club Ct – **33.9 psig**
- 18521 Bridgemore– **38.4 psig**
- 10523 Championship Court- **36.2 psig**
- 5302 Manor Court- **32.9 psig**

NOTE: This would require crossing Floyd’s Fork

Reinforcement Option 4
As a long term reinforcement, it is recommended to connect the Crestwood high pressure line and the Simpsonville high pressure line to bring a high pressure feed into the Polo Fields are for future development.

- Install approximately 10.6 miles of 4-inch high pressure main from the existing 6-inch on Abbott Lane (Crestwood line) to the existing 8-inch on Colt Run Road via Long Run Road and Shelbyville Road.
- Install a 2” Mooney assembly (35%) at the intersection of Abbot Lane and Flat Rock Road to reduce the pressure from the Crestwood line to 180 psig.
- Install a 2” Mooney assembly at Long Run Road and Pope Dale Road to feed the 45 psig medium pressure system.

Minimum gas system pressure (-12 °F)
- 1400 Rutland Club Ct – **30.3 psig**
- 18521 Bridgemore– **43.4 psig**
- 10523 Championship Court- **31.4 psig**
- 5302 Manor Court- **34.2 psig**

NOTE: This would require crossing Floyd’s Fork
Crestwood/Pee Wee Valley/Simpsonville- Reinforcement 2ab

New Facility at Flat Rock Road

Main Extensions

Main Extension

2a

2c

2b
XX. Crestwood/Picadilly High Pressure Extension

The Ellingsworth City Gate Station is located on Blankenbaker Parkway just north of Interstate 64 and serves from Cannons Lane Station in Louisville to Simpsonville and Crestwood. The Bardstown City Gate Station is located on Bardstown Road near Watterson Trail and serves the area from the Bardstown Road Station to Bardstown, KY.

Maximum Allowable Operating Pressure
The Ellingsworth system has a maximum allowable operating pressure of 200 psig and is fed by the Ellingsworth and English Station City Gate Stations. The Bardstown system has a maximum allowable operating pressure of 400 psig from Bardstown Road Station to Bardstown, KY.

Gas System Constraints
If either of the gate stations that feed the Eastern Kentucky Line were temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Ellingsworth system is located at the inlet to the Watterson Trail & Plantside Drive facility (112.9 psig).
The predicted minimum gas system pressure on the Bardstown system is located at the inlet to Mount Washington Station (261.01 psig).

Regulator Operating Capacities
- Ellingsworth City Gate Station – 23.8%
- English Station City Gate Station – 29.1%
- Bardstown City Gate Station – 70.5%

Recommended Gas System Reinforcements
Attach the Eastern Kentucky Line to the Bardstown Line by installing 6.2 miles of 8-inch high pressure pipe from the Jeffersontown Pit at Taylorsville Road and Interstate 265 to the Picadilly valves at the intersection of S Hurstbourne Parkway and Hames. Install a 2” Mooney assembly at Taylorsville Road and I-265 to reduce the pressure to 180 psig.
XXI. Appendix – Mt. Washington High Pressure Distribution System

Options Considered
An attempt was made to parallel the existing 8-inch and 6-inch piping in order to solve the pressure and capacity problems. Almost the entire route (approximately 21 miles) of the system would have to be paralleled in order to correct the pressure and capacity problems.

Scenario 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Preston Highway regulator station to the Shepherdsville regulator pit at Lees Lane and Highway 44 (approximately 12.5 miles). A new regulator facility with a set pressure of 275 psig would have to be installed from the existing 16 inch HP at Preston City Gate Station. In addition, the existing 6-inch piping (approximately 12 miles) would have to be paralleled in order to alleviate the restriction to moving the gas to the south end of the system.

Scenario 2
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Scenario 3
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.
XXI. Appendix – Mt. Washington High Pressure Distribution System (cont’d)

Scenario 4
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line to the south end of the system. This would require installing approximately 16 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

Scenario 5
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line along Hwy 509 and Hwy 245 into Lebanon Junction. This would require installing approximately 12.5 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.
Mt. Washington High Pressure Distribution System – Overview
Mt. Washington High Pressure Distribution System – Mt. Washington Overview

- Mt. Washington
- LG&E Mt. Washington High Pressure Gas Facility
- Shepherdsville
- Highway 44
- Pine Creek Forest
- Jim Beam Clermont Plant
- Highway 44
- LG&E Calvary Gas Transmission Pipeline
- Lebanon Junction
- Jim Beam Boston Plant
- Bardstown
- LG&E 6-inch High Pressure Pipeline on Highway 61
- LG&E 8-inch High Pressure Pipeline on Highway 61
- Publishers Printing
Mt. Washington High Pressure Distribution System – Scenario 2

- Jim Beam Clermont Plant
- Location of new LG&E regulator facility
- 8-inch high pressure extension 14.0 miles along Hwy 245
- Publishers Printing
- Jim Beam Boston Plant
- Lebanon Junction
- LG&E Calvary Gas Transmission Pipeline
Mt. Washington High Pressure Distribution System – Scenario 4

- Mt. Washington
- Maryville
- Shepherdsville
- West Point
- Muldraugh
- Radcliff
- Jim Beam Clermont
- Hwy 245/Cross Country
- Jim Beam Boston
- New Regulator Facility

Bellar
GAS SYSTEM PLANNING

LONG-TERM CONSTRUCTION PLAN

APRIL 2015

Louisville Gas & Electric
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I. Crestwood-Eminence-Bedford High Pressure Distribution

The Crestwood-Bedford high-pressure distribution system serves the areas of Crestwood, Smithfield, Campbellsburg and Bedford. The system is supplied by the Bedford and Crestwood city gate stations and serves a small number of large industrial and commercial customers including Safety Kleen, Steel Technologies, Rose Hill Greenhouse, and Hussey Copper. The Elder Park City Gate Station supplies the Ballardsville pipeline from Zorn Avenue city gate in Louisville to Moody Lane station at Highway 53 in Oldham County.

### Maximum Allowable Operating Pressure

From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig. The Ballardsville pipeline has a maximum allowable operating pressure of 400 psig.

### Minimum Gas System Pressure (-12°F)

<table>
<thead>
<tr>
<th>Pressure</th>
<th>Location</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>350 psig</td>
<td>Eminence Station</td>
<td>189.3 psig</td>
</tr>
<tr>
<td>380 psig</td>
<td>Pleasureville, KY</td>
<td>182.3 psig</td>
</tr>
<tr>
<td>400 psig</td>
<td>Zorn Ave Station</td>
<td>124.6 psig</td>
</tr>
</tbody>
</table>

### Regulator Operating Capacities

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crestwood City Gate</td>
<td>20.6%</td>
</tr>
<tr>
<td>Elder Park City Gate</td>
<td>25.5%</td>
</tr>
<tr>
<td>Bedford City Gate</td>
<td>34.4%</td>
</tr>
</tbody>
</table>

### Gas System Constraints

The Crestwood-Bedford line and Ballardsville Line are dependent upon the successful operation of all three facilities. If any of these three gate stations were temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is supplied by that gate station. In addition, the system is primarily composed of 4-inch pipeline, limiting the system’s capacity for expansion.

### Recommended Gate Station Operating Conditions

- Operate the Elder Park City Gate Station at 300 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the Bedford City Gate Station at 300 psig
I. Crestwood-Eminence-Bedford High Pressure Distribution Cont’d

Reinforcement 1

Connect the Ballardsville pipeline to the Crestwood-Bedford pipeline.
- Install 6,000 feet of 8-inch steel gas transmission pipeline on Highway 53 from Moody Lane to Highway 22.

Minimum Gas System Pressure (-12F):
- Eminence Station ............ 212.7 psig
- Pleasureville, KY ............ 205.4 psig
- Zorn Ave Station ............ 124.6 psig

Regulator Operating Capacities:
- Crestwood City Gate .......... 19.2%
- Bedford City Gate ............ 32.2%
- Elder Park City Gate .......... 25.9%

Reinforcement 2

Replace the Eminence high pressure regulator pit with a control valve.
- Installing a control valve at the Eminence station could be used to isolate either side of the Crestwood-Bedford pipeline should a failure occur and/or in case of emergency shutdown of either city gate station.
  o The Eminence medium pressure system will lose pressure.

Minimum Gas System Pressure (-12F):
- Pleasureville, KY ............. 277 psig

Regulator Operating Capacities:
- Crestwood City Gate ........... 40%
- Bedford City Gate ............ 16%

Reinforcement 3a

Install a new city gate station to supply the LaGrange high pressure system.
- Install a new city gate station near L’Esprit Farms from the Texas Gas Transmission pipeline at the intersection of E Hwy 146 and Lake Jericho in LaGrange.
- Extend 4 miles of 8-inch pipe along E Hwy 146 to the Elder Park/Ballardsville line.
- Install a regulator station to lower the pressure to 100 psig from the new city gate.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

Minimum Gas System Pressure (-12F):
- Eminence Station ............ 316 psig
- Pleasureville, KY ............ 310 psig

Regulator Operating Capacities:
- Crestwood City Gate ........... 14%
- Bedford City Gate ............ 33%

Reinforcement 3b

Install a new city gate station to supply the Bedford-Crestwood & Ballardsville lines.
- Install a new city gate station, fed from the Texas Gas Transmission Pipeline, at Old Sligo Rd and Yager Ln. in LaGrange.
- Extend 1.6 miles of 8-inch pipe along Yager Ln, Old Sligo Rd., and 1.4 miles along N Hwy 53 to Jefferson Street, and 4,000 feet along Jefferson Street.
- Install a regulator station on Jefferson Street to lower the pressure to 90 psig from the new city gate station.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).
Crestwood-Eminence-Bedford Reinforcement Overview

- Old Sligo & Yager city gate
- 1.6 miles of 8-inch pipe
- 4 miles on Hwy 146
- 5.4 miles on Hwy 153
- 6,000 feet on Highway 53

L'Esprit Farms city gate
II. East End Gate Stations Gas Systems Overview

The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393. It serves the Ballardsville pipeline on the northeast border of Louisville from Elder Park to Zorn Avenue. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Crestwood, Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

### Maximum Allowable Operating Pressure

The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the La Grange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

### Minimum Gas System Pressure (-12°F)

<table>
<thead>
<tr>
<th>Pressure (psig)</th>
<th>Location</th>
<th>Pressure (psig)</th>
</tr>
</thead>
<tbody>
<tr>
<td>200</td>
<td>1 Quality Place</td>
<td>84.9</td>
</tr>
<tr>
<td>350</td>
<td>Pleasureville, KY</td>
<td>252.0</td>
</tr>
<tr>
<td>400</td>
<td>Zorn Ave Station</td>
<td>124.6</td>
</tr>
</tbody>
</table>

### Regulator Operating Capacities

<table>
<thead>
<tr>
<th>City Gate Station</th>
<th>Operating Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crestwood City Gate</td>
<td>20.6%</td>
</tr>
<tr>
<td>Elder Park City Gate</td>
<td>25.5%</td>
</tr>
<tr>
<td>LaGrange City Gate</td>
<td>34.4%</td>
</tr>
</tbody>
</table>

### Gas System Constraints

The Crestwood, Ballardsville, and LaGrange systems are dependent upon the successful operation of all three facilities. Each facility independently controls the gas to its area. If any of these three gate stations were temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is supplied by that gate station. An interconnection of the systems is recommended for reliability.
II. East End Gate Stations Gas Systems Overview

**Reinforcement 1**

Connect the Elder Park System to the Crestwood system in case of emergency or scheduled shutdown of the Crestwood City Gate Stations.
- Install 7,500’ of 8-inch pipe on Highway 393.
- Install 6,000’ of 8-inch pipe on Highway 53 (Also in Section I).

<table>
<thead>
<tr>
<th>Minimum Gas System Pressure (-12F):</th>
<th>Regulator Operating Capacities:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zorn Ave Inlet 124.9 psig</td>
<td>Crestwood City Gate 22.0%</td>
</tr>
<tr>
<td>Pleasureville, KY 254.0 psig</td>
<td>Elder Park City Gate 25.0%</td>
</tr>
<tr>
<td>1 Quality Place 85.1 psig</td>
<td>LaGrange City Gate 40.6%</td>
</tr>
</tbody>
</table>

**Reinforcement 2**

Connect the Elder Park System to the LaGrange System in case of an emergency or scheduled shut down of the LaGrange City Gate Station.
- Install 6,600 of 8-inch pipe on Highway 393 from Elder Park Road to Hwy 146.
- Install a facility at Hwy 393 and Hwy 146 to reduce the pressure to 90 psig.
  - 4” Mooney regulators

<table>
<thead>
<tr>
<th>Minimum Gas System Pressure (-12F):</th>
<th>Regulator Operating Capacities:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zorn Ave Inlet 123.0 psig</td>
<td>Crestwood City Gate 19.4%</td>
</tr>
<tr>
<td>Pleasureville, KY 252.0 psig</td>
<td>Elder Park City Gate 29.3%</td>
</tr>
<tr>
<td>1 Quality Place 87.4 psig</td>
<td>Hwy 146 &amp; Hwy 393 20.5%</td>
</tr>
</tbody>
</table>

**Reinforcement 3**

Combine Reinforcement 1 and 2 in case of an emergency or scheduled shutdown of the Lagrange City Gate Station and/or the Crestwood City Gate Station.
- Install 7,500’ of 8-inch pipe on Highway 393.
- Install 5,900’ of 8-inch pipe on Highway 53.
- Install 6,600 of 8-inch pipe on Highway 393 from Elder Park Road to Hwy 146.
- Install a facility at Hwy 393 and Hwy 146 to reduce the pressure to 90 psig.

<table>
<thead>
<tr>
<th>Minimum Gas System Pressure (-12F):</th>
<th>Regulator Operating Capacities:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zorn Ave Inlet 123.0 psig</td>
<td>Crestwood City Gate 0%</td>
</tr>
<tr>
<td>Pleasureville, KY 253.4 psig</td>
<td>Elder Park City Gate 33.4%</td>
</tr>
<tr>
<td>1 Quality Place 87.1 psig</td>
<td>LaGrange City Gate 0%</td>
</tr>
</tbody>
</table>
East End City Gate Stations Reinforcement Overview

- Crestwood City Gate
- LaGrange City Gate
- Elder Park City Gate
- New Hwy 146 & Hwy 393
- To Zorn Ave
- To Pleasureville

- 6,000' on Hwy 53
- 6,600' on Hwy 393
- 7,500' on Hwy 393

Attachment to Response to AG-1 Question No. 440(e)
Page 332 of 356
Bellar
III. LaGrange Medium Pressure Systems

The LaGrange Medium pressure systems are supplied from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-supply systems and one larger, multiple-supply system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

<table>
<thead>
<tr>
<th>Minimum Gas System Pressure (-12ºF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 psig</td>
</tr>
<tr>
<td>25 psig</td>
</tr>
<tr>
<td>30 psig</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Maximum Allowable Operating Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Regulator Operating Capacities</th>
</tr>
</thead>
<tbody>
<tr>
<td>30 psig Systems:</td>
</tr>
<tr>
<td>Hoffman Ln and Parkview Mano</td>
</tr>
<tr>
<td>Button Ct and Commerce Pkwy</td>
</tr>
<tr>
<td>Allen Ln and Artisan Pkwy</td>
</tr>
<tr>
<td>Hwy 53 and Cherry Creek Dr</td>
</tr>
<tr>
<td>New Cedar Point &amp; Old Lagrange</td>
</tr>
<tr>
<td>Regulator Pit at Elder Park Rd</td>
</tr>
<tr>
<td>Moody Ln and Hwy 53</td>
</tr>
<tr>
<td>E Moody Ln and Cal Ave</td>
</tr>
<tr>
<td>Deer Run Rd and Fox Trail Dr</td>
</tr>
<tr>
<td>Granger Rd and Hwy 53</td>
</tr>
<tr>
<td>Park Rd and Hwy 53</td>
</tr>
<tr>
<td>Zhale Smith Rd and Hwy 53</td>
</tr>
<tr>
<td>Springhouse Estates Subdivision</td>
</tr>
<tr>
<td>Hwy 146 and Fort Pickens Rd</td>
</tr>
<tr>
<td>Prestwick Dr and Hwy 53</td>
</tr>
<tr>
<td>Crystal Dr and Grange Dr</td>
</tr>
</tbody>
</table>

| 25 psig Systems: |
| Woodlawn Ave & Lagrange       | 16%       |
| Lagrange medium pressure pit  | 68%       |
| Hoffman Ln                     | 46%       |

| 10 psig Systems: |
| Hwy 393 & Hwy 146      | 1%         |
| Kings Ln & Hwy 146     | 2%         |
| Georgie Way and Moody Ln| 4%         |
| Hazelwood Dr & Elder Park Rd | 14%     |
| Sycamore & Elder Park   | 26%        |

<table>
<thead>
<tr>
<th>Gas System Constraints</th>
</tr>
</thead>
<tbody>
<tr>
<td>Areas of low pressure are constrained by small diameter piping and single regulator stations supplying the systems. The recent reduction in system operating pressure due to new MAOP interpretations of regulations has also put a strain on deliverability. There are multiple single-supply facilities in the LaGrange area that could be removed to reduce the number of dead-end gas systems and reduce O&amp;M costs by removing equipment.</td>
</tr>
</tbody>
</table>
LaGrange System Overview

LaGrange City Gate

Elder Park City Gate

BALLARDSVILLE LINE
III. LaGrange Medium Pressure Systems Cont’d

Reinforcement Purpose
Install piping reinforcements within the LaGrange 30 psig system to address the minimum pressure point and minimize the system pressure drop.

Reinforcement 1a
- Reduce the set pressure of the Hwy 146 & Fort Pickens Rd facility to 25 psig and increase the equipment orifices.
- Install 600’ of 4-inch pipe from the regulator facility to the existing 4-inch pipe on E Jefferson St.

Regulator Operating Capacities:
- Hoffman Ln .......................... 33.3%
- Woodlawn Ave & Lagrange ...... 13.0%
- Lagrange med pressure pit ....... 50.6%
- Hwy 146 & Fort Pickens Rd .... 67.5%

Minimum Gas System Pressure (-12F):
- 503 Parker Place .................... 19.6 psig

Reinforcement 1b
- Follow reinforcement 1a.
- Reduce the set pressure of the Button Ct & Commerce Pkwy facility to 25 psig and increase the equipment orifice.
- Install 3,600’ of 4-inch pipe along Commerce Pkwy to connect the existing systems.

Regulator Operating Capacities:
- Hoffman Ln .......................... 33.3%
- Woodlawn Ave & Lagrange ...... 13.0%
- Lagrange med pressure pit ....... 50.6%
- Hwy 146 & Fort Pickens Rd .... 67.5%
- Button Ct & Commerce Pky .... 25.3%

Minimum gas system pressure (-12°F):
- Cedar Springs Pkwy .......... 21 psig
- 503 Parker Place ............. 19.6 psig

Reinforcement 1c
- Follow reinforcement 1b.
- Reduce the set pressure of the Hoffman Ln & Parkview Manor facility to 25 psig.
- Install 1,000’ of 4-inch pipe along Crystal Drive to connect the systems.

Regulator Operating Capacities:
- Hoffman Ln .......................... 33.3%
- Woodlawn Ave & Lagrange ...... 13.0%
- Lagrange med pressure pit ....... 50.6%
- Hwy 146 & Fort Pickens ........ 67.5%
- Hoffman & Parkview Manor .... 62.3%

Minimum gas system pressure (-12°F):
- Cedar Springs Pkwy .......... 21.4 psig
- 503 Parker Place ............. 19.6 psig
Lagrange Reinforcement 1 Overview

1a
Hwy 146 & Fort Pickens facility
600’ of 4” Pipe

1b
Button Ct & Commerce Pkwy
3,600’ of 4” Pipe

1c
Hoffman Ln & Parkview Manor
1,000’ of 4” Pipe
III. LaGrange Medium Pressure Systems Cont’d

Reinforcement Purpose
Uprate the LaGrange 30 psig medium pressure system to 35 psig to increase the capacity of the system and improve minimum pressures.

Reinforcement 2

- Uprate the Hoffman Ln, Lagrange Medium Pressure City, and Woodlawn Ave & Lagrange Rd facilities to a set pressure of 30 psig.

Regulator Operating Capacities:
- Hoffman Ln .......................... 46.4%
- Woodlawn & Lagrange Rd .... 15.8%
- Lagrange City ......................... 69.3%

Minimum gas system pressure (-12°F):
- 503 Parker Place ................. 21.8 psig
- 1037 Shoreline Dr ............ 22.4 psig
### III. LaGrange Medium Pressure Systems Cont’d

#### Reinforcement Purpose
There are multiple single-supply facilities in the LaGrange area which could be combined to reduce the number of dead-end systems and reduce O&M costs by removing equipment.

#### Reinforcement 3a
Combine single-supply systems along Hwy 53 and retire regulator facilities.
- Install a total of 3,000’ of 4-inch pipe along Hwy 53 to connect the Granger Rd & Hwy 53, Zhale Smith Rd & Hwy 53, Hwy 53 & Cherry Creek Dr, Prestwick Dr & Hwy 53, and Park Rd & Hwy 53 systems.
- Remove the Zhale Smith Rd & Hwy 53, Prestwick Dr & Hwy 53, and Park Rd & Hwy 53 regulator facilities.

**Regulator Operating Capacities:**
- Elder Park Rd .. 34.5%
- Granger Rd & Hwy 53 .. 26.8%
- Hwy 53 & Cherry Creek Dr .. 86.4%

**Minimum gas system pressure (-12°F):**
- 2115 Prestwick Dr .. 27.7 psig

#### Reinforcement 3b
Combine single-supply systems along Elder Park Rd and retire regulator facilities.
- Install a total of 1,800’ of 2-inch pipe to connect the three (3) 10 psig systems.
- Retire the Sycamore Rd & Elder Park Rd, and Hazelwood Dr & Elder Park Rd regulator facilities.

**Regulator Operating Capacities:**
- Elder Park & Elder Park Cutoff .. 83%

**Minimum gas system pressure (-12°F):**
- 2810 Borowick Ct .. 9.1 psig

#### Reinforcement 3c
Combine single-supply systems along W Hwy 146 and retire regulator facilities.
- Reduce set pressure of Hoffman Ln & Parkview, Allen Ln & Artisan Pkwy, and Button Ct & Commerce Pkwy facilities to 25 psig.
- Install 9,000’ of 4-inch pipe to connect systems and provide reinforcement.
- Retire Allen Ln & Artisan, Woodlawn Ave & Lagrange Rd, and Hoffman Ln facilities.
- (Optional Reinforcement: Install 9,700’ of 6” pipe along Fort Pickens Rd to reinforce and facilitate growth).

**Regulator Operating Capacities:**
- Springhouse Estates .. 57.3%
- Lagrange med pressure pit .. 56.8%
- Hoffman & Parkview Manor .. 85.5%
- Button Ct & Commerce Pkwy .. 31%
- Hwy 146 & Fort Pickens Rd .. 35.6%

**Minimum gas system pressure (-12°F):**
- Cedar Springs Pkwy .. 19.1 psig
III. LaGrange Medium Pressure Systems Cont’d

Reinforcement 3d

Combine single-supply systems along Hwy 146 and retire regulator facilities.
- Install a total of 4,800’ of 4-inch pipe to connect the systems.
- Uprate the Hwy 146 system to 35 psig.
- Remove the Industrial Park Rd & Hwy 146, Button Ct & Commerce Pky, and Hwy 393 regulator facilities.

Regulator Operating Capacities:
- Springhouse Estates: 58.4%
- Lagrange med pressure pit: 59.4%
- Hoffman & Parkview Manor: 89.5%
- Hwy 146 & Fort Pickens Rd: 37.3%
- New Cedar Pt & Old Lag: 66.4%
- Fox Run Road: 38.1%
- Hwy 53 & Cherry Creek: 86.4%
- Elder Park Rd: 34.7%
- Grange Dr & Hwy 53: 26.6%

Minimum gas system pressure (-12°F):
- Cedar Springs Pkwy: 19.1 psig
- 2115 Prestwick Drive: 27.7 psig
- 2810 Borowick Circle: 9.1 psig
- 5303 Kamer Ct: 23.2 psig

Reinforcement 4

Combine all regulator retirement reinforcements 3a-3d.
- Install 3.5 miles of 2-inch and 4-inch pipe.
- Uprate the Hwy 146 system to 35 psig.
- Remove the following 11 facilities: Zhale Smith Rd & Hwy 53, Prestwick Dr & Hwy 53, Park Rd & Hwy 53, Sycamore Rd & Elder Park Rd, Hazelwood Dr & Elder Park Rd, Allen Ln & Artisan, Woodlawn Ave & Lagrange Rd, Hoffman Ln, Industrial Park Rd & Hwy 146, Button Ct & Commerce Pky, and Hwy 393.

Regulator Operating Capacities:
- Fox Run Rd: 37.3%
- New Cedar Point & Old Lagrange: 1.2%

Minimum gas system pressure (-12°F):
- 5303 Kamer Ct: 23.2 psig
Lagrange Reinforcement 3 Overview

3a

ZHOLE SMITH RD & HWY 53
PRESTWICK DR & HWY 53
PARK RD & HWY 53
E. MOODY LN
2115 PRESTWICK DR

3b

SYCAMORE RD & ELDER PARK RD
ELDER PARK & ELDER PARK CUTOFF
ELDER PARK RD
Hazelwood Dr & Elder Park Rd

3c

CEDAR SPRINGS PKWY
Optional Reinforcement

3d

NEW CEDAR POINT & OLD LAGRANGE
Hwy 393
HIGHWAY 146
Industrial Park & Hwy 146

= 3,000’ of 4” Pipe
= 1,800’ of 4” Pipe
= 9,000’ of 4” Pipe
= 4,800’ of 4” Pipe
= Retired Facilities
III. LaGrange Medium Pressure Systems Cont’d

**Reinforcement Purpose**
Extend gas mains and uprate LaGrange medium pressure system as described in “An Analysis of the OCEDA Economic Development Campus” dated November 7th, 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 Mcfh.

**Reinforcement 1**

Uprate the system to 50 psig.

Install
- 12,000’ of 4 inch pipe
- 20,500’ of 8 inch pipe
- Facility at Moody Ln & N Fible Ln

Upgrade Equipment
- Hwy 53 & Cherry Creek
- Park Rd & Hwy 53
- Elder Park Rd

Minimum gas system pressure (-12°F):
- 2303 Stoneybrook Ct ...............40.7 psig

Regulator Operating Capacities:
- Moody Ln & N Fible ................34.1%
- Hwy 53 & Cherry Creek ............91.4%
- Elder Park Rd ......................23.3%
- Grange Dr & Hwy 53 ..............77.5%
- Park Rd & Hwy 53 ..................30.1%
III. LaGrange Medium Pressure Systems Cont’d

**Reinforcement Purpose**
Extend gas pipelines and uprate Hwy 393 & Hwy 146 system as described in “An Analysis of Proposed Development at Buckner Crossings” dated October 16th, 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90 Mcfh.

**Reinforcement 1**

Uprate the system to 50 psig.
Install
- 6,600’ of 2 inch pipe
- 6,300’ of 4 inch pipe
- 5,200’ of 6 inch pipe

Upgrade Equipment
- Hwy 393
- Button Ct & Commerce Pkwy

**Minimum gas system pressure (-12°F):**
- New Development .................... 41.0 psig

**Regulator Operating Capacities:**
- Hwy 393 ................................... 36.7%
- Button Ct & Commerce Pkwy ..... 46.3%
IV. Prospect Medium Pressure System

The Prospect system surrounds Hwy 1793 and the Harmony Landing Country Club in Oldham County. This system was recently uprated to 60 psig and is supplied by two regulator facilities off of Hwy 42. Located nearby are 20 and 35 psig systems, supplied by the Riverbluff Farms and the Hillcrest Sub facilities on Hwy 42, which supply the River Glen and Hillcrest areas.

<table>
<thead>
<tr>
<th>Maximum Allowable Operating Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>These subsystems have maximum allowable operating pressures of 20, 35 and 60 psig, as detailed below.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Minimum Gas System Pressure (-12°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>System</td>
</tr>
<tr>
<td>--------</td>
</tr>
<tr>
<td>15 psig</td>
</tr>
<tr>
<td>30 psig</td>
</tr>
<tr>
<td>55 psig</td>
</tr>
</tbody>
</table>

Regulator Operating Capacities

| Hwy 42 & Barbizon Place | 8.1% |
| Hwy 42 & Hwy 1793       | 57.4% |
| Riverbluff Farms & Hwy 42| 11.1% |
| Hwy 42 & Hillcrest Sub  | 31.6% |

Gas System Constraints

Areas of low pressure are constrained by small diameter piping and one-way supply points within the system. It is recommended that the existing systems are connected together to reinforce the system and reduce consequence in the case of an emergency.
IV. Prospect Medium Pressure System Cont’d

**Reinforcement 1a**

Perform uprates and installations as necessary to connect the systems.
- Uprate the Riverbluff Farms & Hwy 42 facility to 60 psig MAOP (NOP = 55 psig).
- Install 1,500’ of 4-inch pipe along River Glades Drive to S Rose Island Rd between the existing 4-inch pipelines.

Minimum gas system pressure (-12°F):
- Louisville Yacht Club ........51.3 psig

Regulator Operating Capacities:
- Hwy 42 & Barbizon Pl ............6.6%
- Hwy 42 & Hwy 1793 ..............44.8%
- Riverbluff Farms & Hwy 42 ....25.7%

**Reinforcement 1b**

Perform uprates and installations to join the Prospect system to the Hillcrest system.
- Complete Reinforcement 1a.
- Uprate the Hwy 42 & Hillcrest and High Meadows Pike facilities to 60 psig MAOP.
- Install 1,200’ of 4” pipe on Hwy 42, tying into the existing main on Hayfield.
- Install 2,600’ of 4” pipe on Hwy 42 from Paramount Way to Hwy 1793.
- Install 200’ of 4-inch pipe at High Meadows Pike and Hwy 42.
- Close valve 98:01.

Minimum gas system pressure (-12°F):
- Louisville Yacht Club ........51.3 psig

Regulator Operating Capacities:
- Hwy 42 & Barbizon Pl ............6.6%
- Hwy 42 & Hwy 1793 ..............59.8%
- Riverbluff Farms & Hwy 42 ....48.6%
- Hwy 42 & Hillcrest Sub ..........18.8%
## V. River Road/Highway 42 Regulator Assemblies

The Elder Park line contains multiple single-feed subsystems ranging in pressure in addition to its contribution to the Jefferson County 50 psig subsystem. Gas System Planning has identified multiple subsystems along River Road that could be combined and regulator facilities that could be removed.

### Maximum Allowable Operating Pressure

The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 300 psig. All medium pressure subsystems have maximum allowable operating pressures of 50 psig, 35 psig, 20 psig, and 10 psig as listed below.

### Regulator Operating Capacities

#### 30 psig Systems:

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>River Rd &amp; Woodside Rd</td>
<td>28%</td>
</tr>
<tr>
<td>River Rd &amp; Harbortown Rd</td>
<td>10%</td>
</tr>
<tr>
<td>River Rd &amp; Duroc Ave</td>
<td>10%</td>
</tr>
<tr>
<td>River Rd &amp; Juniper Beach Dr</td>
<td>8%</td>
</tr>
<tr>
<td>River Rd &amp; River’s Edge</td>
<td>36%</td>
</tr>
<tr>
<td>River Rd Pit Serving Rivercreek</td>
<td>35%</td>
</tr>
<tr>
<td>River Rd &amp; Mockingbird Valley</td>
<td>8%</td>
</tr>
<tr>
<td>Hwy 42 &amp; Hayfield Way</td>
<td>6%</td>
</tr>
<tr>
<td>Hwy 42 &amp; Hunters Ridge Dr</td>
<td>21%</td>
</tr>
<tr>
<td>Hwy. 42 &amp; Hillcrest Sub</td>
<td>32%</td>
</tr>
<tr>
<td>Coveredbridge &amp; Covered Cov</td>
<td>1%</td>
</tr>
<tr>
<td>Coveredbridge &amp; Woodbridge</td>
<td>1%</td>
</tr>
<tr>
<td>High Meadows Pike</td>
<td></td>
</tr>
<tr>
<td>Hunting Creek</td>
<td>30%</td>
</tr>
<tr>
<td>Melrose Retail</td>
<td>3%</td>
</tr>
</tbody>
</table>

#### 45 psig Systems:

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blankenbaker Ln &amp; River Rd</td>
<td>20%</td>
</tr>
<tr>
<td>Glenview Ave &amp; River Rd</td>
<td>11%</td>
</tr>
<tr>
<td>River &amp; Wolf Pen Branch Rd</td>
<td>100%</td>
</tr>
<tr>
<td>10 psig:</td>
<td></td>
</tr>
<tr>
<td>River Rd &amp; Waldoah Pl</td>
<td>8%</td>
</tr>
<tr>
<td>River Rd. &amp; Box Hill Ln</td>
<td>21%</td>
</tr>
<tr>
<td>River Rd &amp; Lime Kiln Ln</td>
<td>19%</td>
</tr>
<tr>
<td>River Rd &amp; Kingfish Pit</td>
<td>43%</td>
</tr>
<tr>
<td>Riverbluff Farms &amp; Hwy 42</td>
<td>11%</td>
</tr>
</tbody>
</table>

#### 15 psig:

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>River Rd. &amp; Box Hill Ln</td>
<td>21%</td>
</tr>
<tr>
<td>River Rd &amp; Lime Kiln Ln</td>
<td>19%</td>
</tr>
<tr>
<td>River Rd &amp; Kingfish Pit</td>
<td>43%</td>
</tr>
<tr>
<td>Riverbluff Farms &amp; Hwy 42</td>
<td>11%</td>
</tr>
</tbody>
</table>

### Gas System Constraints

Maintenance and operating costs can be reduced by eliminating a number of gas regulator facilities. In addition, a reduction of single-supply systems in case of emergency will facilitate lesser system consequences and the merging of systems will improve gas flow.
River Road/Highway 42 Overview

To Elder Park

Zorn Ave Station

Attachment to Response to AG-1 Question No. 440(e)
V. River Road/Highway 42 Regulator Assemblies Cont’d

Reinforcement 1

Combine Kingfish, Mockingbird Valley, and Waldoah systems and remove regulators.

- Uprate the Kingfish and Waldoah systems to 35 psig.
- Install 1,300’ of 4-inch pipe along River Rd to connect the systems.
- Retire the River Rd & Kingfish and River Rd & Waldoah regulator facilities.

Minimum gas system pressure (-12°F):
- 2930 Waldoah Beach Rd.......... 30 psig

Regulator Operating Capacities:
- River Rd & Mockingbird Valley...86%

Reinforcement 2

Combine Box Hill Ln and Rivers Edge Rd systems and remove Box Hill Ln regulator station.

- Uprate the Box Hill Ln system to 35 psig.
- Install 1,400’ of 4-inch pipe along River Rd to connect the Box Hill Ln and Rivers Edge Rd systems.
- Retire the River Rd & Box Hill Ln facility.

Minimum gas system pressure (-12°F):
- 6524 Longview Lane.............. 23 psig

Regulator Operating Capacities:
- River Rd & Rivers Edge Rd...... 56%
Reinforcement 3

Combine Woodside, Glenview, and Lime Kiln systems and remove regulators.
- Uprate Woodside and Lime Kiln systems to 35 psig
- Install 900’ of 4-inch pipe from Arden Rd to Woodside Rd.
- Install 600’ of 4-inch pipe on Glenview Ave at Brittany Woods and 550’ at Orion Rd.
- Install 1,100’ of 4-inch pipe on Lime Kiln Ln at Orchard Ridge Ln.
- Retire the Woodside Rd & Lime Kiln facilities.
- Increase the orifice size of the River Rd & Wolf Pen Branch Rd facility.

Minimum gas system pressure (-12°F):
- Wolfpen Ridge Court..............29 psig

Regulator Operating Capacities:
- Glenview Ave & River Rd........13%
- River Rd & Wolf Pen Branch  62%

Reinforcement 4

Combine Transylvania Ave. Hunter’s Ridge, and Hwy 42 with the Duroc Ave system and remove regulator stations.
- Uprate the Transylvania system to 35 psig
- Install 1,200’ of 4-inch pipe at River Rd and Timber Ridge Dr to connect the systems.
- Retire the River Rd & Transylvania facility.
- Install 2,700’ of 4-inch on Hwy 42 from Hayfield Way to 13310 Hwy 42.
- Retire Hunters Ridge and 13310 Hwy 42 facilities.

Minimum gas system pressure (-12°F):
- Louisville Sailing Club........19 psig

Regulator Operating Capacities:
- River Rd & Duroc Ave............64%
- Hunting Creek....................30%
- Hwy 42 & Hayfield Way..........56%
V. River Road/Highway 42 Regulator Assemblies Cont’d

Reinforcement 5

Combine Rivercreek and Wolfpen Branch systems and retire Rivercreek facility.

- Uprate the Rivercreek system to 50 psig
- Install 30’ of 4-inch pipe at River Rd and Wolf Pen Branch Rd to tie in the systems.
- Retire the River Rd Serving Rivercreek facility.
- Increase the orifice size of the River Rd & Wolfpen Branch facility.

Minimum gas system pressure (-12°F):
- 7604 Wolfpen Ridge Ct ....30 psig
- Wolf Pen Branch Facility outlet....45 psig
- 5700 Captains Quarters Rd....44 psig

Regulator Operating Capacities:
- River Rd & Wolfpen Branch......65%

Reinforcement 6

Combine Prospect systems and retire regulator facilities.

- Uprate the Riverbluff Farms, High Meadows Pike, and Hillcrest facilities to 60 psig MAOP.
- Install 1,225’ of 4-inch pipe along Hwy 42 at Hayfield Way to connect the High Meadows, Hayfield, and Riverbluff systems.
- Install 2,600’ of 4-inch pipe on Hwy 42 at Paramount Way to connect the Hillcrest and Prospect systems.
- Install 200’ of 4-inch pipe at Hwy 42 and High Meadows Pike to connect the High Meadows and Hillcrest systems.
- Install 1,500’ of 4-inch pipe along River Glades Ln to connect the Riverbluff and Prospect systems.
- Close valve 98:01.
- Retire the High Meadows Pike, Riverbluff Farms and Hwy 42 & Hwy 1793 facilities.

Minimum gas system pressure (-12°F):
- Louisville Yacht Club.............44 psig

Regulator Operating Capacities:
- Hwy 42 & Hillcrest.....................53%
- Hwy 42 & Barbizon Pl.................10%
VI. Crestwood/Simpsonville Medium Pressure System

The Crestwood/Simpsonville medium pressure system is a 45 psig single system covering the mid-eastern portion of the LG&E system. It includes areas of East Jefferson County, Crestwood, Anchorage, Simpsonville and Peewee Valley and is bordered by I-265, I-71, and Shelbyville Rd. This system is supplied by eight regulator facilities from both the Eastern Kentucky and the Crestwood high pressure pipelines. The area experiences continual high end residential and commercial growth that is putting a strain on the gas supply.

Regulator Operating Capacities

45 psig Systems:
- Hwy 1694 & Worthington Ln: 16%
- Old Henry & Terra Crossing Bv: 48%
- Conner Station & Colt Run Rd: 10%
- W Hwy 22 & Old Lagrange Rd: 32%

55 psig Systems:
- Glenarm & Halls Hill: 16%

Maximum Allowable Operating Pressure

This Crestwood/Simpsonville system has a maximum allowable operating pressure of 50 psig (NOP = 45 psig).

Minimum Gas System Pressure (-12°F)

| 45 psig | Rutland Club Court  | 20.8 psig |
|         | Bridgemoore Ln      | 23.1 psig |
| 45 psig | Cherry Hills Court  | 23.9 psig |
|         | Championship Ct     | 30.7 psig |
| 45 psig | Pebble Court        | 31.1 psig |
|         | Clore Lane          | 35.6 psig |

Gas System Constraints

The Crestwood/Simpsonville medium pressure system suffers from small diameter trunk lines, unfortunate location barriers such as Floyd’s Fork River, and consistent growth. It has already experienced growth away from any strong sources of gas supplies and the infrastructure is no longer conducive to supporting new development. In order to serve current and future loads, it has been determined that reinforcements are necessary. The neighborhoods of Persimmon Ridge and Polo Fields represent the bulk of the existing constraining system while new subdivisions such as Norton Commons and Brookfield are adding strain to the north.
Crestwood/Simpsonville Overview

Championship Court

Clore Ln

Pebble Ct

Rutland Club Ct

Cherry Hills Ct

Bridgmore Ln

Old Henry & Terra Crossing

English Station Way

Conner Station & Colt Run Rd
VI. Crestwood/ Simpsonville Medium Pressure System Cont’d

### Reinforcement 1a

**General Reinforcements:** Add reinforcements to improve system flow.

- Install 4 miles of 4-inch high pressure steel from the Crestwood MP station to the Old Lagrange & Collins Ln facility.
- Install a 2” Mooney assembly to separate the Crestwood line.
- Install a 2” Mooney assembly at Lagrange Rd and Ash Ave.

**Minimum gas system pressure (-12°F):**

- 6400 Clore Ln .......... 39.0 psig
- 6202 Pebble Ct ............ 30.0 psig
- 10523 Championship Ct .... 30.7 psig

**Regulator Operating Capacities:**

- W Hwy 22 & Old Lagrange .... 28.5%
- Old Lagrange Rd & Collins Ln .... 17.5%
- Westport Rd & Murphy Ln .... 76.4%
- Hwy 1694 & Worthington .... 15.4%
- Hwy 146 & Ash Ave .......... 32.2%

### Reinforcement 1b

Install 1a and add additional small reinforcements to improve system flow.

- Install 1,400’ of 8-inch pipe on W Hwy 22 at Orchard Grass Blvd.
- Install 420’ of 4-inch pipe on Spring Hill Trace at Morningside Dr.
- Install 700’ of 4-inch pipe on Old Lagrange Rd at the Hwy 329 Bypass
- Loop 2,000’ of 6-inch pipe on Worthington Ln at Brownsboro Rd.

**Minimum gas system pressure (-12°F):**

- 6400 Clore Ln .......... 39.1 psig
- 6202 Pebble Ct ............ 37.7 psig
- 10523 Championship Ct .... 38.1 psig

**Regulator Operating Capacities:**

- W Hwy 22 & Old Lagrange .... 28.6%
- Old Lagrange Rd & Collins .... 17.2%
- Westport Rd & Murphy Ln .... 74.3%
- Hwy 146 & Fort Pickens .... 17.6
VI. Crestwood/ Simpsonville Medium Pressure System Cont’d

Reinforcement 2a
Accounting for growth: Install reinforcements to increase the pressure at Clore Ln after 100 Mcfh has been added.

- Complete Reinforcement 1b
- Loop 2 miles of 6-inch pipe along Hwy 22 and Clore Ln from the Crestwood pit to Spring Hill Trace.

<table>
<thead>
<tr>
<th>Minimum gas system pressure (-12°F):</th>
</tr>
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<tbody>
<tr>
<td>6400 Clore Ln</td>
</tr>
<tr>
<td>6202 Pebble Ct</td>
</tr>
<tr>
<td>10523 Championship Ct</td>
</tr>
</tbody>
</table>

Regulator Operating Capacities:

- W Hwy 22 & Old Lagrange............43.6%
- Old Lagrange Rd & Collins..........17.9%
- Westport Rd & Murphy Ln............76.7%
- Hwy 1694 & Worthington Ln.........18.0%

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Reinforcement 2b
Accounting for growth: In addition to reinforcement 2a, install pipe across I-71 to connect to the Glenarm & Halls Hill system.

- Uprate the Glenarm & Halls Hill system to 50 psig (45 MOP)
- Install 1 mile of 8-inch pipe across I-71 and Harrod’s Creek at Hwy 329 to Zaring Road to connect and loop existing pipe.

<table>
<thead>
<tr>
<th>Minimum gas system pressure (-12°F):</th>
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</thead>
<tbody>
<tr>
<td>6400 Clore Ln</td>
</tr>
<tr>
<td>6202 Pebble Ct</td>
</tr>
<tr>
<td>10523 Championship Ct</td>
</tr>
</tbody>
</table>

Regulator Operating Capacities:

- W Hwy 22 & Old Lagrange............36.6%
- Old Lagrange Rd & Collins...........17.6%
- Westport Rd & Murphy Ln............75.5%
- Glenarm & Halls Hill................88.9%
VI. Crestwood/ Simpsonville Medium Pressure System Cont’d

Reinforcement 3a

Improve minimum system pressures in Polo Fields.

- Install 1 mile of 6-inch pipe on Flat Rock Rd near Long Run Golf Course.
- Install 1,600’ of 4-inch pipe on Bridgemore Ln to connect to the existing pipe on Shelbyville Rd.
- Loop 4.3 miles of pipe along Shelbyville Rd with new 6-inch pipe from the existing 8-inch to Conner Station & Colt Run Rd facility. Connect to Flat Rock Road.

Minimum gas system pressure (-12ºF):
- 1415 Rutland Club Ct ......... 30.8 psig
- 18521 Bridgemore Ln ......... 40.9 psig
- 1205 Cherry Hills Ct .......... 32.0 psig

Regulator Operating Capacities:
- Conner Station & Colt Run Rd .... 8.3%
- English Station Way ................. 45.9%
- Old Henry & Terra Crossing ....... 44.7%

Reinforcement 3b

Improve minimum system pressures in Polo Fields.

- Install 2.5 miles of 6-inch pipe along Aiken Road from Arnold Palmer Blvd to Flat Rock Rd (cross Floyds Fork).
- Install 2.5 miles of 6-inch pipe along Johnson Rd from Aiken Rd to the existing main at Shelbyville Rd (cross Brush Run).
  - Both require the crossing of waterways.

Minimum gas system pressure (-12ºF):
- 1415 Rutland Club Ct ......... 33.5 psig
- 18521 Bridgemore Ln ......... 31.4 psig
- 1205 Cherry Hills Ct .......... 34.1 psig

Regulator Operating Capacities:
- Conner Station & Colt Run Rd .... 4.5%
- English Station Way ................. 47.5%
- Old Henry & Terra Crossing ....... 51.9%

Reinforcement 3c

Improve minimum system pressures in Polo Fields.

- Combine Reinforcements 3a and 3b.

Minimum gas system pressure (-12ºF):
- 1415 Rutland Club Ct ......... 37.0 psig
- 18521 Bridgemore Ln ......... 41.5 psig
- 1205 Cherry Hills Ct .......... 36.8 psig

Regulator Operating Capacities:
- Conner Station & Colt Run Rd .... 7.8%
- English Station Way ................. 45.3%
- Old Henry & Terra Crossing ....... 47.8%
Crestwood/Simpsonville Reinforcement 3 Overview

=Minimum Pressure

=River Crossing
Question No. 441

Responding Witness: Lonnie E. Bellar

Q-441. Provide a copy of the latest study LG&E-KU conducted regarding the feasibility and cost effectiveness of joining a Regional Transmission Organization.

A-441. See attached.
1 Executive Summary

A cross-functional team was assembled to conduct a high level analysis of the estimated costs and benefits of LG&E-KU (“LKE” or “the Companies”) regional transmission organization (RTO) membership, specifically for Midwest Independent Transmission System Operator (MISO) and PJM Interconnection (PJM). The analysis of joining MISO and PJM covered a ten year study period from 2013 through 2022. The analysis was modeled after a similar study, EKPC RTO Membership Assessment\(^1\), performed by Charles River Associates (CRA) for East Kentucky Power Corporation in their consideration of joining PJM.

- **RTO membership is unfavorable.** LKE’s RTO Membership Analysis shows an unfavorable ten-year present value for RTO membership ranging from ($103) M for PJM to ($216) M for MISO.
- **Key driver is “backbone” transmission costs.** Allocation of large transmission expansion projects costs across RTO members is the primary cost driver of RTO membership.

2 Methodology

LKE Transmission Strategy and Planning assembled a cross–functional team for the RTO Membership Analysis.\(^2\) The team was comprised of representatives from Transmission Policy & Tariffs, Federal Regulation & Policy, Regulated Trading and Dispatch, and Economic Analysis. The CRA EKPC RTO Membership Assessment was used as a general guideline for this analysis.

- The methodology for the LKE analysis was consistent with the methodology and testimony from the 2006 MISO exit proceedings.
- The methodology took into consideration changes to the tariff structures and business practices of the RTOs since the exit proceedings.

The intent of the analysis was to incorporate updated data and information to assess the costs and benefits of RTO membership at a high level, as opposed to an exhaustive

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\(^1\)March 2012 http://psc.ky.gov/pscscf/2012%20cases/2012-00169/20120503_ekpc_application_volume%201.pdf, Exhibit RLL-2

\(^2\) The Compliance Department was apprised of all meetings to ensure maintenance of Standards of Conduct between Transmission function and Trading function employees.
RTO Membership Analysis

These results were viewed as a threshold to determine if further in-depth study is warranted.

3 Key Assumptions
This analysis was conducted for a ten year horizon, 2013 through 2022, a period identical to the CRA study conducted for EKPC. The following key simplifying assumptions were incorporated into the analysis:

- LKE would continue to maintain its own capacity to meet a target planning reserve margin established consistently with current processes.
- No changes in locational marginal prices (LMP) due to planned RTO transmission expansions
- No impact from Firm Transmission Rights/Auction Revenue Rights (FTR/ARR) and congestion cost
- No impact from allocation of over collection of marginal losses
- No impact from uplifts or make whole payments other than those identified
- No impact from potential transmission cost sharing within alternative, non-RTO Order 1000 regional planning region

4 Cost / Benefit Components

4.1 Allocation of “Backbone” Transmission Expansion Costs
The key driver of the outcome of this analysis was the allocation of “backbone” transmission expansion costs.

- For PJM, transmission expansion costs of $176 million (present value) represent more than half of the estimated absolute cost of RTO membership (excluding the benefits).
- For MISO these costs are $241 million (present value), approximately 60% of the estimated absolute cost of membership (excluding the benefits).

4.1.1 MISO Multi-Value Projects
Under current MISO policy, the cost of new transmission projects that address energy policy and/or provide widespread benefits across the footprint are considered “multi-value projects” (MVP). The cost of MVP are allocated 100% “postage stamp” to load,

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3 MISO collects incremental value of financial losses through the locational marginal price (LMP), which can result in over-collection. MISO has a process to allocate any over-collection back to the load serving entities.
RTO Membership Analysis

i.e., all load pays the same rate for MVP irrespective of where located in the footprint, and are recovered under Schedule 26A of the MISO Tariff. LKE’s share of the $5.4 billion in MVP projects currently identified in the Midwest ISO Transmission Expansion Planning (MTEP) process is based on the “indicative annual charges for approved MVP” published on the MISO website, applied to LKE loads projected per the 2013 Business Plan. As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period.

4.1.2 PJM Regional Transmission Expansion Planning
Under current PJM policy, the cost of new “backbone” high voltage transmission projects approved under its annual Regional Transmission Expansion Planning (RTEP) process is allocated on a uniform basis to all PJM loads based on the non-coincident annual peak of each PJM transmission zone. These charges are recovered under Schedule 12 of the PJM tariff. “Backbone” facilities comprise “Regional Facilities” that operate above 500 kV and “necessary lower voltage facilities” that operate below 500 kV that must be constructed or strengthened to support new Regional Facilities. As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period. The allocation to LKE for projects documented in the RTEP within this analysis period has been estimated using PJM’s allocation methodology and is a key cost driver for the PJM case.

4.2 Modeled Components
Two components of the analysis, Operating Reserve and Trade Benefits, were estimated by Generation Planning (GP) using the Companies’ planning models. Because the models were already developed for other planning purposes, only minimal changes were required to use the models to estimate these components.

4.2.1 Operating Reserve
The reduced operating reserve capacity benefits of joining MISO or PJM were estimated by reducing the Companies’ “spinning reserve” requirement from 230 MW to 100 MW, for a present value benefit of $14 M. GP revised the operating reserve input in the Companies’ reliability planning software, SERVM, which resulted in a target system planning reserve margin (RM) of 15% (1% lower than the existing target RM of 16%).

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5 For discussion of the “unique circumstances” surrounding Entergy joining Midwest ISO that justify Energy’s five year MVP exemption and eight year MVP cost phase-in, see 139 FERC ¶ 61,056 at ¶¶ 70,181,213.
6 CRA Study, p. 12.
7 With the existing 16% RM target, GP would choose to purchase temporary capacity through a PPA in years with an annual RM between 14% and 15% and would choose permanent capacity in a year with a RM below 14%. With
RTO Membership Analysis

GP used this new RM to evaluate the impact to the Companies’ expansion plan using a spreadsheet model to calculate the expected RM and using Strategist software.

The table below shows the expected RMs with no new capacity after Cane Run 7 in 2015 and the corresponding capacity additions needed with the existing and new target RMs.

<table>
<thead>
<tr>
<th>Year</th>
<th>RM w/o New Capacity</th>
<th>Existing Expansion Plan (16% RM Target)</th>
<th>New Expansion Plan (15% RM Target)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td>14.7%</td>
<td>165 MW PPA</td>
<td>NA</td>
</tr>
<tr>
<td>2017</td>
<td>14.1%</td>
<td>165 MW PPA</td>
<td>NA</td>
</tr>
<tr>
<td>2018</td>
<td>12.5%</td>
<td>605 MW CCCT</td>
<td>605 MW CCCT</td>
</tr>
</tbody>
</table>

With the new 15% target RM, the 165 MW Power Purchase Agreements (PPAs) in 2016 and 2017 in the existing expansion plan could be avoided, resulting in an estimated cost savings of $9.6 M each year. However, the absence of the PPAs results in higher expected system production costs of approximately $0.2 M in both 2016 and 2017, as estimated by GP using PROSYM software.

4.2.2 Trade Benefits

The trade benefits of joining MISO or PJM were estimated by GP using PROSYM as lower native load production costs and higher off-system sales (OSS) margins that resulted from the following:

- Reducing the spinning reserve requirement from 230 MW to 100 MW
- Eliminating RTO expenses for OSS and purchases
- Eliminating 3rd party transmission expenses for purchases
- Eliminating LG&E-KU transmission expenses for OSS and purchases
- Eliminating $2 “costless adder” for OSS and purchases

The eliminated LG&E-KU transmission and $2 costless adder expenses were deducted from the total savings because they do not represent actual savings to the Companies. The PJM and MISO analyses used electricity price forecasts specific to each RTO.

- The resulting net trade benefits total between $11 M and $15 M annually over the study period for each RTO
- The present value of trade benefits is approximately $90 M for both PJM and MISO.

the new 15% RM target, a PPA would be chosen for years with RMs between 13% and 14%; permanent capacity would be chosen below 13%.
4.3 Other Components

4.3.1 Administrative charges
Both MISO and PJM have various tariff schedules to recover the administration cost of operating the markets and providing services to their respective footprints. For MISO, these costs were estimated using $/MWh cost projections contained in the MISO 2011 Budget presentation published on their website. Administrative costs for PJM were estimated based upon the costs noted in the CRA study.

4.3.2 Transmission Revenue
Both MISO and PJM allocate third-party transmission revenues to the transmission owners in their respective footprints. MISO uses a formula based on allocation of plant in service and transmission flows to allocate transmission revenue. This allocation was assumed to be approximately $1 M per year to LKE, loosely based upon prior experience in MISO. The projected allocation to LKE from PJM was estimated using the PJM transmission revenues shown in the CRA study, multiplied by LKE’s estimated proportion of PJM’s total transmission revenue requirement, which calculated to be approximately 2.7%.

4.3.3 Uplift Costs
Both MISO and PJM have various mechanisms for allocating uplift costs that result from operations of the markets and payments made to others that are not offset by revenues. Typically, for both RTOs, these costs are the result of committing units in real-time that were not committed in the day-ahead market. In MISO these costs are referred to as “revenue sufficiency guarantee” (RSG) costs and, in the PJM market, as “operating and balancing reserve cost”. Both RTOs also have other sources of these “revenue insufficient” costs. For MISO, RSG cost was assumed to be a net zero for LKE, but a load ratio share of the historic Revenue Neutrality Uplift cost of $100 million per year was assumed. For this analysis, the PJM allocation of these costs to LKE was assumed to be negligible, which is consistent with the CRA study.

4.3.4 FERC Charges
Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just “wholesale” load as LKE is assessed outside of an RTO. For this analysis, the

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9 Load ratio share roughly estimated based on LKE peak load of 7200 and total MISO peak load of ~107,000 or 6.6%
RTO Membership Analysis

current FERC assessment charges were escalated for inflation and applied to LKE Energy for load as given in the 2013 Business Plan.

4.3.5 Net Zero Components
Two components, congestion cost/ARR/FTR and ancillary services market, have been identified that would be considered of net zero benefit. It is expected that the value of the ARR/FTR may equal or exceed the congestion costs; however, the net cost or benefit will not be known with certainly until such rights are issued. A company may choose to self-supply ancillary services and be no worse off than before joining an RTO. While there could be some potential benefit in the RTO market, there is no means to estimate the value of such benefit.\(^\text{10}\)

4.3.6 Eliminated Administration Charges
Membership in either PJM or MISO would result in a re-alignment of internal cost for the provision of certain services. For the purposes of this analysis, it was assumed that LKE would no longer need the current Independent Transmission Operator (ITO) or Reliability Coordinator (RC) services provided by TranServ and TVA, respectively. There also likely would be a reduction in cost in the balancing authority services provided by internal staffing. This reduction would be offset to some degree by increases in internal staffing to manage the day to day operations in the RTO, as well as for back office settlement of the RTO statements and invoices on a daily basis.

4.3.7 De-Pancaking
LKE currently pays “depancaking” cost to certain entities as a result of the 2006 MISO exit.\(^\text{11}\) It is assumed that all of these payments would cease if LKE were to join either PJM or MISO.

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\(^{10}\) See Charles River Associates EKPC RTO Membership Assessment (March 2012)

\(^{11}\) LKE pays costs for certain entities to keep them from having to pay more for transmission now than when the Companies were in MISO, known as depancaking costs.
## MISO Summary

### Cost

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<td>MISO Admin Cost ($M)</td>
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<tr>
<td>MISO FERC Fees (Incremental of Present) ($M)</td>
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<td>-1.6</td>
<td>-1.6</td>
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<td>-34.8</td>
<td>-43.6</td>
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### Benefits

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<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>6.75%</td>
<td>7.1</td>
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<td>12.3</td>
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<td>0.0</td>
<td>9.4</td>
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<td>LKE Elimination of TVA RC Cost ($M)</td>
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### Net of Cost + Benefits

| Net of Cost + Benefits                  | -4.8  | -9.2  | -18.8 | -23.0 | -27.7 | -42.7 | -49.7 | -56.2 | -53.6 | -52.7 |               | -216.5|
## PJM Summary

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<td>LKE Elimination of TEE Group Admin Charge ($M)</td>
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<td><strong>Sum of Benefits</strong></td>
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| Net of Cost + Benefits                    | 9.6  | -2.3 | -19.0 | -11.2 | -10.9 | -19.6 | -19.0 | -31.6 | -31.6 | -31.3 | -103.0                     |
RTO Membership Analysis

7 Additional Considerations and Uncertainties

7.1 NERC Compliance Requirements
Since the companies own and operate certain facilities used in interstate commerce or that have the potential to impact the bulk electric system, the Companies are required to comply with Reliability Standards for planning and operating the bulk electric system, as developed by the North American Electric Reliability Corporation (NERC). Under current operations, LG&E/KU Transmission Owner (TO) are responsible for over 1,200 NERC compliance requirements falling under the Reliability Standards. It is estimated that slightly over 300 of these requirements would be performed by an RTO and no longer an internal function if the companies were to join and RTO. While this reduction is noted qualitatively, the study does not estimate a financial cost/benefit related to compliance.

7.2 Regulatory Environments – MISO, PJM
There has been considerable realignment of RTO memberships since 2006. Examples include the departure from MISO of First Energy and Duke-Ohio. Both entities are now PJM transmission owning members. MISO has retained and, with the joining of Entergy, BREC, and Dairyland Power, gained members who operate in non-contestable load areas, while PJM has solidified membership of transmission owners operating in states that have retail access and unbundled utilities.\textsuperscript{12} Given this realignment between MISO and PJM membership, it is likely that more of Kentucky’s regulatory paradigm and LKE’s traditional regulated utility business model would be accommodated in MISO versus PJM. For example, the entities within MISO that had been advocating for capacity markets are simply not as politically strong as they once may have been. Moreover, membership in PJM would almost certainly pit LKE interests against those of the traditional PPL companies on matters of significance to all concerned.

7.3 Future RTO Market/Program Implementation
The costs/benefits of “markets” or “programs” that each RTO may implement in the future are uncertain and so cannot be reflected in this analysis.

8 Conclusion
The results of this threshold analysis reveal that a more in depth study of the cost and benefits of RTO membership is not warranted at this time. Further, the study results confirm the prudence of LKE continuing with the establishment the Southeast Order 1000 Planning Region.

\textsuperscript{12} Ameren-Illinois’s continued membership in MISO being a notable exception.