COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES	)))))	ADMINISTRATIVE CASE NO. 2006-00494

SECOND DATA REQUEST OF COMMISSION STAFF TO JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES

Jurisdictional electric distribution utilities ("distribution utilities") are requested, pursuant to 807 KAR 5:001, to file with the Commission the original and six copies of the following information, with a copy to all parties of record. The information requested herein is due on or before February 23, 2007. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the person who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information requested herein has been provided, in the format requested herein, reference may be made to the specific location of said information in responding to this information request. Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") may file one document as KU/LG&E including a separate response for each company within each tabbed response where necessary.

All electric distribution utilities are to respond to the following questions:

1. Describe in detail how the company utilizes all of the reliability measures it monitors.

2. Has the company determined an appropriate operating range or performance threshold based on these measures? If yes, identify.

3. Describe in detail how the company develops formal plans to address its worst performing circuits. If the company does not develop such plans, indicate so in the response.

4. Why are momentary outages excluded?

5. Why are major event days or major storms excluded?

6. Provide a hard copy citing of the Rural Utilities Service ("RUS") reliability monitoring or reporting requirements or, in the alternative, provide an accessible Internet site.

7. Provide and describe in detail any service restoration or outage response procedure utilized.

8. Refer to the RUS drawing M1.30G "RIGHT-OF-WAY CLEARING GUIDE" ("ROW Guide"), a copy has been provided in Appendix A.

a. Is this type of clearance requirement appropriate for all areas of a distribution system? If not, what types of exclusions or exceptions should be made?

b. If the distribution utility is not already following this guide, provide an estimate of the cost and time-line to implement.

9. Refer to North American Electric Reliability Corporation ("NERC") standard FAC-003-1 "Transmission Vegetation Management Program" ("NERC Standard"), a copy is attached in Appendix B.

a. Does the company prefer the type of standard described in the NERC Standard over the type of standard described in the ROW Guide? Explain why you prefer one over the other.

b. Refer to section R3 of the NERC Standard and substitute "distribution" for "transmission." Is the distribution utility capable of meeting the reporting requirements described in the section? If not, why not?

c. Again referring to section R3 as applied to distribution, how many sustained outages would be reportable for the calendar year 2006?

10. Provide and discuss any right-of-way maintenance standard which is preferable to those identified in questions 1 and 2 above.

<u>Duke Energy Kentucky is to respond to the following questions:</u>

11. How many substations are equipped with Supervisory Control and Data Acquisition ("SCADA")? How many are not?

12. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

<u>Kentucky Power is to respond to the following questions:</u>

13. How many substations are equipped with SCADA? How many are not?

14. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

<u>KU/LG&E are to respond to the following questions:</u>

15. How many substations are equipped with SCADA? How many are not?

16. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

17. Describe in detail the capabilities of the Outage Management System to monitor outages and provide reliability-related information.

Big Sandy is to respond to the following question:

18. Why doesn't Big Sandy exclude any outages from its reliability measures?

Clark Energy is to respond to the following question:

19. Describe the value of the measures described in items 1 though 4 of Clark's response to Question No. 1 in Staff's first data request.

Farmers is to respond to the following question:

20. Can Farmers monitor System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") in addition to Customer Average Interruption Duration Index ("CAIDI")?

Grayson is to respond to the following questions:

21. Why doesn't Grayson monitor or track distribution reliability?

22. Does RUS require that Grayson report any distribution reliability measures or service interruptions?

23. Does Grayson have the capability to monitor SAIDI, SAIFI and CAIDI?

24. How does Grayson define a sustained outage?

Inter-County is to respond to the following question:

25. Can Inter-County monitor SAIFI and CAIDI in addition to SAIDI?

Jackson Energy is to respond to the following question:

26. Describe in detail the capabilities of the Outage Management Software to monitor outages and provide reliability-related information.

Jackson Purchase is to respond to the following questions:

27. Why doesn't Jackson Purchase exclude any outages from its reliability measures?

28. Describe in detail the capabilities of the new outage management and reporting system to monitor outages and provide reliability-related information.

Kenergy is to respond to the following questions:

29. Why doesn't Kenergy exclude any outages from its reliability measures?

30. How many substations are equipped with SCADA? How many are not?

31. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

32. Describe in detail the capabilities of the Outage Management System to monitor outages and provide reliability-related information.

Licking Valley is to respond to the following question:

33. Can Licking Valley monitor SAIFI and CAIDI in addition to SAIDI?

Meade County is to respond to the following questions:

34. Why doesn't Meade County exclude any outages from its reliability measures?

35. Describe in detail the capabilities of the Hunt Turtle II AMI System relating to monitor outages and provide reliability-related information.

Nolin is to respond to the following questions:

36. How many substations are equipped with SCADA? How many are not?

37. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

38. Describe in detail the capabilities of the new AMR System to monitor outages and provide reliability-related information.

Owen is to respond to the following question:

39. Can Owen monitor SAIDI, SAIFI and CAIDI in addition to the measures noted in its response to Staff's First Data Request?

Salt River is to respond to the following questions:

40. Can Salt River monitor CAIDI in addition to SAIDI and SAIFI?

41. How many substations are equipped with SCADA? How many are not?

42. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

43. Describe in detail the capabilities of the AMR System to monitor outages and provide reliability-related information.

Shelby Energy is to respond to the following questions:

44. Can Shelby Energy monitor SAIDI, SAIFI and CAIDI in addition to the measures noted in its response to Staff's First Data Request?

45. Why doesn't Shelby Energy exclude any outages from its reliability measures?

46. How many substations are equipped with SCADA? How many are not?

47. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

South Kentucky is to respond to the following questions:

48. How many substations are equipped with SCADA? How many are not?

49. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

50. Describe in detail the capabilities of the Outage Management System to monitor outages and provide reliability-related information.

Taylor County is to respond to the following questions:

51. Can Taylor County monitor SAIFI and CAIDI in addition to SAIDI?

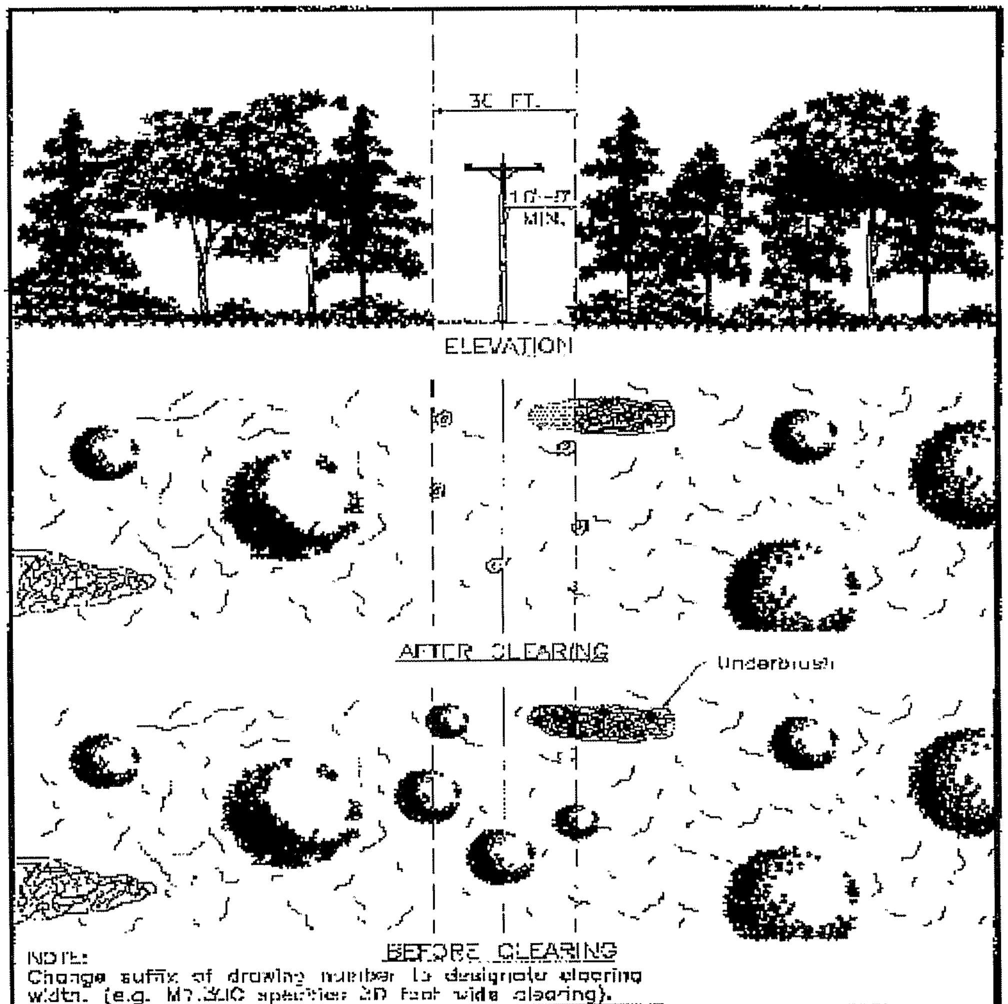
52. Why doesn't Taylor County exclude any outages from its reliability measures other than those where equipment automatically restores service?

Beth O'Donnell
Executive Director
Public Service Commission
P.O. Box 615
Frankfort, Kentucky 40602

DATED February 9, 2007

cc: All Parties

Appendix A



JPEC clears right-of-way 30' wide for single phase lines and 40' wide for multi-phase lines.	RIGHT-OF-WAY CLEARING GUIDE	
	APRIL 2005 RUS	M1.30G (R1)

Appendix B

A. Introduction

1 **Title: Transmission Vegetation Management Program**

2 **Number:** FAC-003-1

3 **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. Applicability:

4.1. Transmission Owner.

4.2. Regional Reliability Organization.

4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

5 Effective Dates:

5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.

5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications1 .

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   RRO

   NERC

   1.2. Compliance Monitoring Period and Reset

   One calendar Year

   1.3. Data Retention

   Five Years

   1.4. Additional Compliance Information

   The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

   2.1. Level 1:

   2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

   2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

   2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

   2.2. Level 2:

   2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

   2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

   2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

   2.3. Level 3:

   2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

   2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06