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BEFORE THE
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AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES - CASE NO. 2006-0494

CLARK ENERGY
COOPERATIVE, INC
WINCHESTER, KENTUCKY

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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. 2006-0494

RESPONSE TO DATA REQUEST OF
THE KENTUCKY PUBLIC SERVICE COMMISSION
DATED DECEMBER 12, 2006

Clark Energy Cooperative, Inc. ("Clark Energy"), pursuant to the Public Service Commission's (PSC) information request dated December 12, 2006, hereby submits the following response dated January 8th, 2007 regarding Case No. 2006-0494.

DATE: January 8th, 2007

ATTEST:

Paul G. Embs
President & CEO

Clark Energy Cooperative, Inc.
Case No. 2006-0494
Request for Information by PSC

Question No. 1: Does utility management measure, monitor, or track distribution reliability?

Answer: Yes.

Part a: If so, describe the measures used and how they are calculated.

Answer: Detail accounts of system outages are entered into Milsoft's Utility Solutions Dispatch Software program as they occur noting all pertinent information. Multiple reports are then available to break the outages into manageable data for evaluation.

Some of the most used reports are as follows:

1. Devices out multiple times – Helps track down reoccurring problems
2. Outage cause report – contains information on specific causes (a list of causes are included later in this report) and equipment failure (highlights faulty materials and equipment)
3. Customers affected by area – lists numbers of customers still off in an area during an outage.
4. Monthly outages – reports are made monthly to Clark Energy's board of directors
5. Monthly outages by feeder – lists substation and individual circuit outage numbers.

RUS requires Cooperatives to track and report an indice on their annual form 7 financial and statistical report with the acronym SAIDI (system average interruption duration frequency index) that measures the total duration of interruptions that a customer would see on average each year. One factor added into this equation is extreme storm, which is included in the reliability chart listed later in this report

Another indice reviewed by utility management is CAIDI (customer average interruption duration frequency) which measures how efficient we are in restoring service after an interruption.

Internal corporate reliability goals were set and monitored by our board of directors in 2006 so they could see what level of reliability the cooperative is providing.

Part b: If reliability is monitored, provide the results for the past 5 years for system wide reliability.

Answer:

	Year	Power supplier	Extreme storm	Pre-arranged	Other	TOTAL
	2001	0.38	0.00	0.00	1.40	1.78
	2002	0.02	0.00	0.10	0.83	0.95
	2003	1.30	9.06	0.00	1.27	11.63
	2004	0.18	0.00	0.02	2.83	3.03
	2005	0.30	0.00	0.01	1.01	1.32

Question No. 2: Are any outages excluded from your reliability measurement? If so, what criteria are used to exclude outages?

Answer: Only momentary outages are excluded from our reliability measurement.

Question No. 3: Does the utility differentiate between momentary and sustained outages?

Answer: Yes

Part a: What criteria are used to differentiate?

Answer: Momentary outages and a sustained outage are two different events and are handled as such. Only sustained outages longer than 1 minute are considered to be an outage and are entered into the outage management software program.

The cost of retrofitting all down line reclosers to report momentary events would be very expensive to install and maintain.

Part b: Is information about momentary interruptions recorded?

Answer: Yes. Reading are taken from automatic reclosing device counters several times each year for preventive maintenance issues.

Question No. 4: At what level of detail does the utility record customer outages (individual customer, by re-closer, by circuit, by substation, etc.)?

Answer: Below is a list of items contained within the outage management program:

1. Starting and ending time and date of outage
2. Total number of customers out of service
3. Individual customers information (address, account number, phone number ect.)
4. Customers substation and substation feeder name
5. Priority customers (including life support information)
6. Protective devises projected to be open
7. Notes and remarks pertinent to outage
8. Check list of possible problems from customer
9. Calling history and outage history of each customer calling in
10. Recorded voice messages from customer

Question No. 5: How does the utility detect that a customer is experiencing an outage?

Answer: All outages must be reported by the customer/member.

Question No. 6: How does the utility know when a customer is restored?

Answer: A concerted effort is made to return the customers call to make sure service is back on. Our outage management program is equipped with a call back feature that we use to assist dispatchers during large outages.

Question No. 7: Are the causes of outages categorized and recorded? If they are, provide a list of the categories used.

Answer: Yes, outage causes are categorized and recorded. The list is as follows:

1. Aircraft
2. Animal
3. Animal/bird
4. Animal/large bird
5. Bad conductor
6. Bad connection
7. Cattle rubbing
8. Customer responsible
9. Deterioration
10. Dig in
11. Fire
12. Ice
13. Imbalance
14. Insect
15. Lightning
16. Low Clearance
17. Major Storm
18. Other
19. Overload
20. Pole washout/high water
21. Power supplier
22. Scheduled
23. Snow
24. Squirrel
25. Tree/limb in R/W
26. Tree/limb out of R/W
27. Unknown cause
28. Vandals
29. Vehicles
30. Wind
31. Wire break
32. Woodcutter

Question No. 8: Can the utility record outage information for each circuit in the system including for each customer outage:

Part a: Length of each disruption?

Answer: Yes

Part b: Number of customers affected by each disruption?

Answer: Yes

Part c: Number of customers served by each circuit?

Answer: Yes

Part d: Cause of each interruption?

Answer: Yes

Question No. 9: If the answer to any part of Item 8 is no, what would be required to enable the utility to collect this level of data?

Answer: N/A

Part a: Provide an estimated cost to obtain this level of detail.

Answer: N/A

Part b: Provide an estimated timeline to implement such upgrades.

Answer: N/A

Question No. 10: Does the utility follow any type of standard (e.g., ANSI A300) for trimming trees in or near to the distribution right-of-way?

Answer: As a rule, Clark Energy Cooperative follows RUS specifications for the clearing of overhead lines which calls for 15 feet of clearance (30 feet total) on either side of a primary overhead line and in the case of trimming trees beneath the line, a minimum of 8 feet from the nearest tree branch to the lowest primary line.

Directional pruning techniques are also used to direct tree limbs growth away from the lines.

Question No. 11: What criteria does the utility use to determine when vegetation maintenance or tree trimming is required?

Answer: Consideration is given according to species of trees, yearly rain fall and the density of brush and trees in any given area. Some parts of our system have a heavy growth of trees while other areas are more agricultural in nature.

To combat this, while our servicemen are performing their semi-annual system line patrol, they draw up work orders by priority on trees in the Right/of/Way corridor including yard trees that are in need of trimming or cutting. These work orders are given to the Right/of/Way contractor's general foreman for routing and completion.

Question No. 12: Is the tree trimming performed by utility personnel or by contractor? If by contractor, describe the controls management uses to ensure trees are trimmed per utility requirements.

Answer: The majority of tree trimming work for Clark Energy is preformed by a qualified ROW contractor. The Manager of System Maintenance is in charge of inspecting the work completed by the contractors.

Question No. 13: Is any portion of the utility system subject to local codes or ordinances regarding tree trimming or vegetation management?

Answer: No

Part a: Which areas of the system are covered by local codes or ordinances?

Answer: N/A

Part b: For each covered area, what do the local codes or ordinances require?

Answer: N/A

Question No. 14: How often does the utility clear its distribution easements?

Answer: There are several factors involved when discussing the length of time it takes to rotate the system. Here is a list of schedules that we try to maintain.

1. High priority trees – 2 years
2. Customer request work orders – 3 to 6 months
3. Low volume foliar spray – 4 to 5 years
4. System maintenance clearing – 6 to 7 years

Question No. 15: How much has the utility spent on distribution easement clearing for each of the last 5 years? Include the cost per mile expended.

Answer:

Year	2001	2002	2003	2004	2005	
Total cost	$886,441.98	$863,970.38	$999,998.64	$1,120,684.26	$1,080,277.90	
Miles of line	2,713	2,741	2751	2,775	2,793	
Cost per mile	$326.73	$315.21	$363.50	$403.85	$386.78	

Question No. 16: What annual amount of money is included in the current retail rates for distribution easement clearing?

Answer: Clark Energy's budget for 2007 for Right/of/Way clearing is approximately $ 1,000,000.