OWEN Electric

A Touchstone Energy® Cooperative

March 31, 2005

Ms Beth O'Donnell
Public Service Commission
211 Sower Boulevard
PO Box 615
Frankfort, Kentucky 40602-0615

Dear Ms O'Donnell:

Enclosed is the response to Administrative Case No. 2005-00090.

Sincerely,

Owen Electric Cooperative

Robert Marshall
President & CEO

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APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 2005-00090 DATED March 10, 2005

1. Provide a summary description of you utility's resource planning process. This should include a discussion of generation, transmission, demand-side, and distribution resource planning.

   Owen Electric Cooperative (OEC), in conjunction with East Kentucky Power (EKP), bases its power requirement study on existing load levels, past load growth percentages and anticipated load additions to the system. Existing substation and distribution facilities are evaluated based on present and future load levels. Based upon the criteria established in the short and long range work plans, system improvement projects are evaluated and prioritized. Immediate projects forecasted in the long range work plan would be included in the present two-year work plan. All projects in the two-year work plan are evaluated for compatibility with the long range work plan.

2. Are new technologies for improving reliability, efficiency and safety investigated and considered for implementation in your power generation, transmission and distribution systems? **Yes.**

- Infrared Cameras – Implemented.
- Outage Management System – Implemented.
- Fault Indicators – Implemented.
- Battery Powered Tools – Implemented.
- Automated Meter Reading – Not implemented, still under review.
- Bucket Trucks For Service Technicians – Implemented (2 years to go on 4 year plan)
- Work Management System (Staking, Mapping & Scheduling) – 90% implemented.
- Automated Vehicle Locating System - Implemented.
- Automated Defibrillators – 90% Implemented.

5. Provide actual and weather-normalized annual coincident peak demands for calendar years 2000 through 2004 disaggregated into (a) native load demand, firm and non-firm; and (b) off-system demand, firm and non-firm.

a. Native Load Demand

Annual Peak	Actual Peak Demand (MW)
December-00	177.8
August-01	178.8
August-02	189.0
January-03	207.0
December-04	208.8

b. Weather Normalized Peak Demand (MW)

Annual Peak	Weather Normalized Peak Demand (MW)
December-00	203.9
August-01	190.6
August-02	186.0
January-03	223.8
December-04	224.1

18. Provide your utility's definition of "transmission" and "distribution."

Transmission facilities operate above 35 KV and distribution facilities operate below 35 KV.

26. Provide the yearly System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI"), excluding major outages, by feeder for each distribution substation on your system for the last 5 years.

OEC TOTAL SYSTEM DATA

Year	SAIFI	SAIDI (In Hours)
2003	.033	2.472
2004	.029	2.383

Data was not available for years 2000 through 2002. Specific feeder information is not available at this time.

27. Provide the yearly SAIDI and SAIFI, including major outages, by feeder for each distribution substation on your system for the last 5 years. Explain how you define major outages.

OEC TOTAL SYSTEM DATA

Year	SAIFI	SAIDI (In Hours)
2000	.048	2.399
2001	.046	2.226
2002	.038	2.928
2003	.034	3.021
2004	.034	5.420

OEC now has the capability to retrieve the above data. Our Outage Management System was installed mid-year of 2002 and was not fully functional until early 2003, all data prior to that was estimated. Specific feeder information is not available at this time. A major outage is defined as any outage affecting 5% or greater of our customer base.

28. What is an acceptable value for SAIDI and SAIFI? Explain how it was derived.

OEC has not developed specific values for these two indices.

29. Provide the yearly Customer Average Interruption Duration Index ("CAIDI") and the Customer Average Interruption Frequency Index ("CAIFI"), including and excluding major outages, on your system for the last 5 years. What is an acceptable value of CAIDI and CAIFI? Explain how it was derived.

Including Major Outages

Year	CAIDI	CAIFI (In Hours)
2000	50.367	0.020
2001	48.230	0.021
2002	76.975	0.013
2003	89.241	0.011
2004	158.335	0.014

OEC now has the capability to retrieve the above data. Our Outage Management System was installed mid-year of 2002 and was not fully functional until early 2003, all data prior to that was estimated. Specific feeder information is not available at this time.

Year	Excluding Major Outages CAIDI	CAIFI (In Hours)
2003	74.90	0.0133
2004	82.17	0.0120

Data was not available for years 2000 through 2002. Specific feeder information is not available at this time.

30. Identify and describe all reportable distribution outages from January 1, 2003 until the present date. Categorize the causes and provide the frequency of occurrence for each cause category.

Cause Description	Outages	Percent
Age/Deterioration	120	3.4
Birds/Animals	386	10.9
Equipment/Installation	407	11.5
Major Storm	25	0.7
Member/Public	135	3.8
Power Supplier	21	0.6
R.O.W. Preventable	104	2.9
R.O.W. Unpreventable	117	3.3
Scheduled	420	11.9
Unknown	414	11.7
Weather	1379	39.1
Totals	3528	

31. Does your utility have a distribution and/or transmission reliability improvement program?

a. How does your utility measure reliability?

SAIDI is used as a benchmark on a system-wide basis. Specific feeder reliability is handled individually.

b. How is the program monitored?

Outage Management System

c. What are the results of the system?

Threshold, targets, and stretch goals are adjusted each year.

d. How are proposed improvements for reliability approved and implemented?

Proposed improvements for reliability are approved by the Board.

32. Provide a summary description of your utility's:

a. Right-of-way management program. Provide the budget for the last 5 years.

OEC has a five year mechanical cutting schedule for its right-of-way and a two-year schedule on subdivision right-of-way clearing. OEC's mechanical and herbicide right-of-way programs are based on OEC's "Right-of-way Control Standards and Contractor Requirements." The budget for mechanical right-of-way clearing has been:

2000	$ 710,000
2001	$1,042,500
2002	$1,042,500
2003	$1,166,500
2004	$1,100,000

b. Vegetation management program. Provide the budget for the last 5 years.

OEC uses low-volume herbicide applications to supplement the mechanical right-of-way trimming. The budget for the herbicide program has been:

2000	$100,000
2001	$150,000
2002	$150,000
2003	$150,000
2004	$200,000

c. Transmission and distribution inspection program. Provide the budget for the last 5 years.

OEC distribution facilities are patrolled every two years in accordance with PSC requirements. Critical feeders are patrolled as often as every three months and infrared annually. No budget has been established for line patrol.

Below is the pole inspection program budget for the past five years:

2000	$ 93,099
2001	$104,132

2002	$ 79,198
2003	$135,612
2004	$143,585

33. Explain the criteria your utility uses to determine if pole or conductor replacement is necessary. Provide costs/budgets for transmission and distribution facilities replacement for the years 2000 through 2025.

OEC's criteria for determining pole replacement is based on OEC's pole treatment program and is outlined in the OEC "Pole Inspection Treatment Specification and Contractor Requirements." Underground conductor replacement is based on the criteria of two failures in a year or three failures overall for conductor in a specific area. Overhead conductor replacement is based on the outage history and selected by severity and frequency. Below are the budget amounts in these areas over the last five years:

Year	**Pole**	**O/H Conductor**	**U/G Conductor**
2000	$256,000	$1,263,000	$170,000
2001	$449,000	$2,235,000	$198,000
2002	$472,000	$1,978,000	$145,000
2003	$520,000	$1,296,000	$125,000
2004	$535,000	$1,857,000	$100,000
2005	$600,000	$2,200,000	$100,000
2006	$600,000	$2,200,000	$100,000
2007	$600,000	$2,200,000	$100,000
2008	$600,000	$2,200,000	$100,000
2009	$650,000	$2,200,000	$100,000
2010	$650,000	$1,800,000	$100,000
2011	$650,000	$1,800,000	$100,000
2012	$650,000	$1,800,000	$100,000
2013	$650,000	$750,000	$100,000
2014	$650,000	$750,000	$100,000
2015	$650,000	$750,000	$100,000
2016	$700,000	$750,000	$100,000
2017	$700,000	$750,000	$200,000
2018	$700,000	$750,000	$200,000
2019	$700,000	$750,000	$200,000
2020	$700,000	$750,000	$200,000
2021	$700,000	$750,000	$200,000
2022	$700,000	$750,000	$200,000
2023	$700,000	$750,000	$200,000
2024	$700,000	$750,000	$200,000
2025	$700,000	$750,000	$200,000

Parties Responsible For Answers to Appendix "B"

1)	Chuck Gill
2)	Bob Hood
5)	Chuck Gill
18)	Chuck Gill
26)	Rusty Williams
27)	Rusty Williams
28)	Bob Hood
29)	Rusty Williams
30)	Rusty Williams
31)	Rusty Williams
32) a, b	Chuck Gill
32) c	Rusty Williams
33)	Chuck Gill