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PUBLIC SERVICE
COMMISSION

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Elizabeth O'Donnell, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

May 18, 2006

Re: ***CONSIDERATION OF THE REQUIREMENTS OF THE FEDERAL ENERGY POLICY ACT OF 2005 REGARDING TIME-BASED METERING, DEMAND RESPONSE AND INTERCONNECTION SERVICE - ADM CASE 2006-00045***

Dear Ms. O'Donnell:

Enclosed for filing are an original and ten (10) copies of the Joint Testimony of Kent W. Blake, Greg Fergason, and Michael T. Leake on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company with regard to the above-cited case.

Copies are being provided to all parties of record.

Sincerely,

Kent Blake

Kent Blake

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE REQUIREMENTS OF THE FEDERAL ENERGY POLICY ACT OF 2005 REGARDING TIME-BASED METERING, DEMAND RESPONSE, AND INTERCONNECTION SERVICE	))))))	 CASE NO: 2006-00045

TESTIMONY OF
KENT W. BLAKE
DIRECTOR OF STATE REGULATION AND RATES
E.ON U.S. SERVICES, INC.

Filed: May 18, 2006

Q. Please state your name and business address.

A. My name is Kent Blake. I am currently employed as Director of State Regulation and Rates for E.ON U.S. Services, Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is threefold. First, I will briefly summarize the testimony of Gregory Fergason, who discusses some of the technical aspects of time-based rates, smart metering, and demand response programs, and Michael Leake, who discusses the technical aspects of the Companies' current interconnection standards and concerns about implementing a statewide standard.

Second, I will explain why the Companies are optimistic about the potential benefits of broadening the use of smart metering and time-based rates but nonetheless oppose a statewide and mandatory standard or set of standards concerning smart metering, time-based rates or demand response programs.

Third, I will explain at a high level why, though the Companies are not opposed to a statewide interconnection standard based on IEEE 1547 *per se*, they retain concerns related to cost allocation, reliability, and safety with regard to interconnection of distributed generation.

Q. Please summarize the testimony filed today by Gregory Fergason and Michael Leake.

A. Gregory Fergason is the Demand Side Management ("DSM") program manager for E.ON U.S. Services, Inc. His testimony discusses time-based pricing programs and provides the number of residential, commercial, and industrial customers on demand response tariffs, as well as an estimate of the associated load available from these customers because of demand response. He further explains why the Companies believe that, of the time-based schedules set forth in the federal Energy Policy Act of 2005 ("EPAct 2005"), critical peak pricing with a demand response component (e.g., use of load control devices) would be the most likely to result in a shift of load in the Companies' service territory from peak to off-peak.

Michael Leake is the Group Leader, Electric System Codes & Standards for E.ON U.S. Services, Inc. His testimony addresses what the Companies believe the Commission should at a minimum include in a mandatory interconnection standard. He also answers in the affirmative the Commission staff's question whether the Companies comply with the IEEE 1547 interconnection standard with respect to distributed generation of 10 MVA or less. Finally, Mr. Leake addresses the Companies' concerns with respect to programs targeting customers' open transition generation beyond the Load Reduction Incentive Rider the Companies already offer their customers.

<u>**Smart Metering, Time-Based Rates, and Demand Response Programs**</u>

Q. Please state the Companies' position on time-based pricing programs. Should the Commission adopt the time-based pricing standard in the Energy Policy Act of 2005? Should the Commission mandate any form of time-based pricing?

A. Because the Companies believe there is currently insufficient data concerning the demand response effect of incremental time-based rate programs beyond those the

Companies currently offer, as well as insufficient data concerning the cost-effectiveness of such programs, the Companies are opposed to any statewide and mandatory standard or set of standards concerning smart metering, time-based rates or demand response programs. The Companies further believe certain kinds of smart metering, time-based rates, and demand response programs will likely function better or worse in certain areas of Kentucky than others depending on logistical challenges, consumption patterns, and other issues that vary from area to area and utility to utility. Thus, in lieu of creating a mandatory standard or set of standards at this time, the Companies recommend that the Commission authorize pilot programs, such as the one LG&E is currently planning, to gather data to inform any future decisions the Commission might wish to make concerning these issues.

Q. Is LG&E preparing to engage in a pilot program to investigate the cost-effectiveness of a particular kind of time-based rate, smart metering, and demand response program?

A. Yes. For a complete description of the program, please see the Companies' Response to Commission Staff's Second Information Request No. 22(a). In brief, in its Final Order dated June 30, 2004 in Case No. 2004-00433 (LG&E's last base rate case), the Commission approved the unanimous resolution of a substantial number of issues as filed by the parties in a document entitled "Partial Settlement Agreement, Stipulation and Recommendation" ("the Settlement"). The Settlement partially outlines the pilot program on page 9 of the Final Order:

> "LG&E will establish a real time pricing pilot program for a 3-year term and participation will be limited up to 50 customers under Rate R and up to 50 customers under Rate GS; customers under

Rate LP are to be eligible for inclusion in the second year of the program."

Section 3.6 of the Settlement states that the goals of the pilot are: "(i) to determine the impact of the pilot program on its affected customers; (ii) to determine the amount of revenue loss from the pilot program, if any; (iii) to evaluate customer acceptance of the real time pricing program and (iv) to evaluate the potential for implementing the RTP [Real Time Pricing] program as either a permanent demand-side management program or as a standard rate schedule."

As Gregory Fergason more fully describes in his testimony filed in this proceeding today, LG&E currently has designed the pilot program to use smart meters with demand response capabilities (i.e., load control functions) to implement a time-based rate structure with a critical peak pricing component. LG&E believes that this time-based rate, smart metering, and demand response structure, coupling time of use pricing (i.e., critical peak pricing) with load control devices, may prove to be cost-effective for the Companies and their customers; however, the Companies cannot affirmatively draw any conclusions until they implement, and collect and analyze data from, the pilot program. LG&E will refrain from instituting the pilot until the conclusion of this proceeding to ensure that the pilot will comply with any requirements the Commission may establish in this proceeding.

Q. The pilot you describe above is directed toward residential and small commercial customers. What, if any, demand response tariffs and riders do the Companies already have in place for those customers as well as large commercial and industrial customers?

A. Please see the attached lists of LG&E's and KU's current demand response tariffs and riders (Exh. KWB-1). The lists contain brief descriptions of the tariffs and riders.

<u>Interconnection Standards</u>

Q. Please state the Companies' position on interconnection standards. Should the Commission adopt the interconnection standard in the Energy Policy Act of 2005? Should the Commission mandate any form of interconnection standard?

A. The Companies are not opposed to a mandatory interconnection standard *per se*. In particular, the Energy Policy Act of 2005 ("EPAct 2005") interconnection standard, set out in § 1254 of EPAct 2005, incorporates the standards contained in IEEE 1547. As the Companies stated in their Response to Commission's Order dated February 24, 2006, Interconnection Question No. 1, the Companies already have on file several tariffs such as Small Qualified Facilities and Large Qualified Facilities that involve interconnection to the Companies' distribution system. These interconnections are based on the IEEE 1547 standard and could be modified to specify requirements for all types of interconnections, even small capacity interconnections such as net metering. Thus, the Companies' have no objection to an interconnection standard based on IEEE 1547; however, the Companies do have certain cost, reliability, and safety concerns with respect to distributed generation.

Q. What are the Companies' cost-related concerns with respect to distributed generation?

A. Whatever interconnection standard(s) the Commission chooses to mandate, the Companies believe, with the exception of small or simple interconnections such as net metering (which require a minimum level of review), the interconnecting customer should, consistently with the principle of cost causation, bear the majority of associated costs. This should include costs related to the following:

- System planning studies required to accommodate the interconnection
- Special metering requirements
- Technical review and administration of the interconnection requirements
- Infrastructure enhancements required to accommodate larger interconnection distributed generation
- Protective equipment required at the interconnection point provided by the utility

In addition, distributed generation customers should pay for the stand-by service they require and be compensated for no more than the utilities' avoided cost for energy customers provide.

Q. What are the Companies' reliability- and safety-related concerns with respect to distributed generation?

A. Safety is always among the Companies' primary concerns, and it is certainly a primary concern with respect to interconnected systems, as well as customers' maintenance of their interconnected systems. For example, because the Companies do not control a customer's interconnected generation, there is no way to guarantee that a distribution line to which the customer's generation is interconnected will be de-energized when a lineman works on the line. Moreover, the addition of distributed generation could result in longer restoration times if it becomes standard practice physically to isolate (visibly open) distributed generation sites from the system before restoration work is performed. Also of concern is the cost to install safe and reliable switching to connect distributed generation to the grid and to provide remote control of these switches to ensure proper utilization during peak periods.

Reliability is also a significant concern. Typical small distributed generation would have limited impact on system planning because of its questionable availability when it is most needed. Distributed generation from renewable resources, particularly wind and hydroelectric, is not a reliable supply during summer peak conditions. Distributed generation from small emergency generators has not been proven to be capable of running for long periods of time during summer peak conditions.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says that he is Director of State Regulation and Rates for E.ON U.S. Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Kent W Blake
KENT W. BLAKE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of May, 2006.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

VICTORIA B. HARPER
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Sept. 20, 2006

Louisville Gas and Electric Company

Time-based Metering/Demand Response Tariff Provisions

Tariff/Rider	Description of Service/Provision
Residential	
Commercial Industrial	
Tariff LC-TOD	Commercial Time-of-Day
Tariff LP-TOD	Industrial Time-of-Day
Tariff LI-TOD	Atypical Time-of-Day
Rider CSR1	Curtailable Service Rider
Rider CSR2	Curtailable Service Rider
Rider CSR3	Curtailable Service Rider
Rider LRI	Load Reduction Incentive
Tariff STOD	Small Time-of-Day

Service Description

Commercial Time-of-Day - Available to customers above 2MW. Charges utilize a combination of seasonal and time-of-day demand price differentials.

Industrial Time-of-Day - Available to customers above 2MW. Charges utilize a combination of seasonal and time-of-day demand price differentials.

Atypical Time-of-Day - Available to customers above 20MW. Charges utilize a combination of seasonal and time-of-day demand price differentials.

Curtailable Service Rider 1 - Restricted to customers as of 5/12/04. Provides a credit for customer agreeing to reduce demand upon request

Curtailable Service Rider 2 - Available as a rider to any power schedule for customers agreeing to reduce demand a minimum of 1MW upon request. Provides a credit to billing.

Curtailable Service Rider 3 - Available as a rider to LI-TOD customers agreeing to reduce demand upon request. Customer receives a billing credit for compliance.

Load Reduction Incentive - Available as a rider to any customer agreeing to off-set a minimum of 500KW with customer's own generation upon request at a price based on current conditions.

Small Time-of-Day - Pilot program available to commercial customers with loads between 250K and 2MW. Charges utilize a combination of season demand changes and time-of-day energy charges.

Kentucky Utilities Company

Time-based Metering/Demand Response Tariff Provisions

Tariff/Rider	Description of Service/Provision
Residential	
Commercial Industrial	
Tariff LCI-TOD	Commercial/Industrial Time-of-Day
Tariff LMP-TOD	Mine Power Time-of-Day
Tariff LI-TOD	Atypical Time-of-Day
Rider CSR1	Curtailable Service Rider
Rider CSR2	Curtailable Service Rider
Rider CSR3	Curtailable Service Rider
Rider LRI	Load Reduction Incentive
Tariff STOD	Small Time-of-Day

Service Description

Comm/Ind Time-of-Day - Available to customers above 5MW. Charges utilize time-of-day demand price differentials.

Mine Power Time-of-Day - Available to customers above 5MW. Charges utilize time-of-day demand price differentials.

Atypical Time-of-Day - Available to customers above 20MW. Charges utilize time-of-day demand price differentials.

Curtailable Service Rider 1 - Restricted to customers as of 5/12/04. Provides a credit for customer agreeing to reduce demand upon request

Curtailable Service Rider 2 - Available as a rider to any power schedule for customers agreeing to reduce demand a minimum of 1MW upon request. Provides a credit to billing.

Curtailable Service Rider 3 - Available as a rider to LI-TOD customers agreeing to reduce demand upon request. Customer receives a billing credit for compliance.

Load Reduction Incentive - Available as a rider to any customer agreeing to off-set a minimum of 500KW with customer's own generation upon request at a price based on current conditions.

Small Time-of-Day - Pilot program available to commercial customers with loads between 250K and 2MW. Charges utilize a combination of season demand changes and time-of-day energy charges.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE	)	
REQUIREMENTS OF THE FEDERAL	)	
ENERGY POLICY ACT OF 2005	)	**CASE NO:**
REGARDING TIME-BASED METERING,	)	**2006-00045**
DEMAND RESPONSE, AND	)	
INTERCONNECTION SERVICE	)	

TESTIMONY OF
GREGORY FERGASON
DEMAND-SIDE MANAGEMENT PROGRAM MANAGER
E.ON U.S SERVICES, INC.

Filed: May 18, 2006

Q. Please state your name and business address.

A. My name is Gregory Fergason. I am currently employed as Demand-Side Management ("DSM") Program Manager for E.ON U.S. Services, Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies"), the applicants in this proceeding. My business address is 220 W. Main St., Louisville, Kentucky 40202.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in this proceeding and in the Commission's investigation (Case No. 2000-00459) into the Companies' DSM program filing, as well as previously filed DSM proceedings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address certain outstanding questions from the Commission staff concerning time-based rates and smart metering standards of the kinds set out in the Federal Energy Policy Act of 2005, as well as to describe LG&E's planned pilot program involving time-based pricing, smart metering, and a demand-response component.

Q. Please identify what time-based pricing programs can be implemented without smart meters.

A. Offering seasonal rates, such as different rates in winter and summer, would qualify as time-based pricing without a need for smart meters or any other new technology. The shortcomings of seasonal rates are that they do not address critical peaks during any given day, and the difference between seasonal prices and ordinary prices may not be significant enough from the standpoint of the customer to impact usage patterns. Though seasonal rates may align prices more closely to our summer peaking generation system costs, many customers would not be able to make decisions that would change energy usage on a seasonal basis. Residential and small commercial customers can more easily and practically shift usage during a given day by changing thermostat settings, shutting off water heaters and other large loads, and deferring other uses to off peak times.

Rates such as Time Of Use ("TOU") and Critical Peak Pricing ("CPP") require meters that are capable of registering usage at various times of the day (TOU) or also be capable of receiving instructions indicating a real time rate component time period (e.g., CPP). The Companies consider this type of meter to be a "smart" meter.

More complex rates, such as hourly day-ahead or hourly real-time, would require meters capable of providing interval (hourly) data and in the case of a real-time rate, a communications capability. The interval data retrieved from these meters would in turn need to be translated into hourly usage for billing purposes.

Meters are available with two-way communications capabilities that allow for automated meter reading, remote reconnect-disconnect, and dialog with other customer equipment (e.g., air conditioners and water heaters). These more sophisticated meters may or may not be necessary or appropriate for the implementation of time-based rates or demand response programs, depending on the goals and designs of a particular rate or program.

Q. Please provide the number each of residential, commercial and industrial customers on demand response tariffs and an estimate of the associated load available from these customers because of demand response.

A. The Companies' Demand Conservation program has the following participation levels and demand reduction potential as of April 1, 2006:

	Devices Controlled	Summer Peak Demand Reduction
Residential	91,320	85 Mw
Commercial	1,904	1.7 Mw

The Companies' customers on various demand response rates are listed below.

Louisville Gas and Electric

Rate	Customers	MW Impact
LC-TOD	66	unknown *
LP-TOD	68	unknown *
LI-TOD	0	0
CSR1	2	75
CSR2	0	0
CSR3	0	0
LRI	0	0
STOD	35	unknown *

Kentucky Utilities

Rate	Customers	MW Impact
LCI-TOD	41	unknown *
LMP-TOD	7	unknown *

LI-TOD	1	0
CSR1	1	2.5
CSR2	0	0
CSR3	1	85
LRI	2	5
STOD	53	unknown *

*STOD is currently being evaluated and data is not available on possible load shifting. The Time-of-Day rates are not monitored for load shifting but billing data suggests any load shifting is minimal and evaluation of data did not indicate a significant load shifting would result from the Time-of-Day rates when they were initiated.

Q. Of the time-based schedules set forth in EPAct 2005, which would more likely result in a shift of load from peak to off-peak given the circumstances in Kentucky?

A. Speaking only for the Companies and their service areas, considering the costs of implementation, weather, and the relatively low prices for electricity, a critical peak pricing rate in conjunction with a DSM program would have costs and benefits that I believe would likely maximize demand response for residential and commercial customers in a cost effective manner. The CPP rate, as the Companies have proposed, has pricing that is known to the customer for 99% of the hours in a year. The majority of hours in a year, approximately 87%, would have rates lower than those currently in our tariffs. The high cost and critical peak hours, approximately 13% of the total hours, have a rate significantly higher than our current tariff rates. We expect that the "critical", real-time component would have rates approximately 6 times that of our current tariff rates. This CPP rate structure sends a pricing signal to the customer that I believe will result in usage being shifted from the higher demand and cost periods, to the lower demand periods. This tariff does not require the customer to make extreme lifestyle changes and should appeal to a significant number of customers.

Previous TOU programs offered by utilities have required the customer to manually make the changes necessary to shift usage from higher priced periods to lower priced periods, and have not sent the significant pricing signal we believe necessary to reduce peak demand in a significant and sustained manner. The results seen at several utilities indicate that customers on TOU rates initially respond by shifting usage from peak hours to off-peak hours but that the effect is not sustained over time in large part due to the need for customers' active participation in load shifting and the fact that the large price signal that can occur with a critical peak component is not possible with a TOU rate structure. We believe that through the use of a real-time, "critical" price component, prices will better be able to reflect the peak conditions being experienced by the generation system including system load, wholesale prices, and operational events. This "critical," real time price component would be activated during the same time periods that our load control devices are activated. As part of the DSM component, customers would be provided programmable thermostats equipped with a radio receiver to receive critical peak pricing signals, and load control switches for water heaters and other larger loads. Considering that heating, cooling, and water heating make up 1/2 to 2/3 of these customers' total load, by automating temperature settings with the thermostat and shutting off water heaters and other large loads based on the current price, customers can shift usage out of the periods of highest cost and system demand without having to manually control these systems on a daily or hourly basis, while retaining control of heating and cooling they currently do not have with a load control switch. Customers can also make other lifestyle and usage changes that would result in additional energy usage being shifted outside the highest cost and demand periods for further savings.

The Companies believe that more complex tariffs, such as hourly rates, provide little if any additional benefit, and likely would result in both lower customer participation rates and increased program costs. Furthermore, we believe that time based rate structures, without enabling technology through companion DSM programs, will result in lower levels of customer participation, and lower demand savings per customer on a sustained basis. Changes in the Companies' generation costs over the hours of the day show that these costs could be grouped into 3 or 4 time-differentiated prices that could be understood by the customer and closely reflect actual system costs. The critical, real-time component allows the pricing structure to react to high system demands and costs when justified by load, operational events, or wholesale prices. Costs would most likely not vary on an hourly basis due to the additional complexity of hourly pricing. With hourly pricing, metering and billing costs would increase and customers may react negatively to the constant potential change in pricing that would occur. Under a CPP tariff, customers would know the price of electricity for 99% of the hours in the year.

Q. Please explain the pilot program that the Companies have been investigating.

A. LG&E's current expectation for a CPP pilot is that it will couple RTP with demand-side management ("DSM") technology. More particularly, the program for residential and small commercial customers would utilize smart metering, programmable thermostats, load control switches, and a variable rate structure that would include a time of use ("TOU") component and a critical peak price (real-time) component. Critical peak hours would be during times of high system demand and pricing, generally the same time periods that load control devices are activated. Under LG&E's current pilot program design, customers would be provided programmable thermostats equipped with a radio receiver to receive critical peak pricing signals (as well as other pricing tier signals) and load control switches for water heaters and other larger loads. Automation of the usage of these loads would allow the customer to shift usage without manual intervention on a daily basis. The Companies expect that some customers would choose to find additional energy uses that could be shifted from peak to off-peak periods. Indeed, our investigation for this program indicates that the technology is available and has shown to be successful with a large number of customers at Gulf Power resulting in high customer satisfaction and significant shifting of usage from peak hours.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gregory Fergason**, being duly sworn, deposes and says that he is a DSM Program Manager for E.ON U.S. Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gregory Fergason
GREGORY FERGASON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of May, 2006.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

VICTORIA B. HARPER
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Sept. 20, 2006

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE	)	
REQUIREMENTS OF THE FEDERAL	)	
ENERGY POLICY ACT OF 2005	)	CASE NO:
REGARDING TIME-BASED METERING,	)	2006-00045
DEMAND RESPONSE, AND	)	
INTERCONNECTION SERVICE	)	

TESTIMONY OF
MICHAEL LEAKE
GROUP LEADER, ELECTRIC SYSTEM CODES & STANDARDS
E.ON U.S SERVICES, INC.

Filed: May 18, 2006

Q. Please state your name and business address.

A. My name is Michael Leake. I am currently employed as Group Leader, Electric System Codes and Standards for E.ON U.S. Services, Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies"), the applicants in this proceeding. My business address is 820 W. Broadway, Louisville, Kentucky 40202.

Q. Have you previously testified before this Commission?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the Companies' recommendation to the Commission in their investigation regarding interconnection requirements for distributed resources as required by the Federal Energy Policy Act of 2005 ("EPAct 2005").

Q. What do you see as the potential impact and benefits of implementing in Kentucky the Interconnection standard included in section 1254 of EPAct 2005?

A. Speaking only for the Companies, the impact of implementing the EPAct 2005 interconnection standard should not be significant, provided interconnected generation is not required to be incorporated into system resource plans due to its questionable availability, is not subsidized beyond avoided cost through rate incentives and all associated costs of interconnection are assigned to the customers requesting interconnection. This includes costs for system impact studies, facility improvements, and special equipment, as well as any ongoing costs associated with managing the interconnection. The impact on the Companies to review and manage interconnections will be minor provided the number and nature of requests for interconnection do not increase dramatically. Safety and reliability of interconnected resources is of high importance and must be insured.

The Companies have existing interconnection standards and have willingly interconnected customer generation on request, generally for the purpose of co-generation or to accommodate closed-transition (make before break) standby generation. Common interconnection standards combined with modifications to existing tariffs or adoption of new ones could encourage additional connection of distributed resources to the distribution grid. For example, it could be possible to encourage customers with larger amounts of existing or planned standby generation to interconnect this generation in a manner that would allow them to take advantage of one of the available demand response rates already in place. However, past efforts to encourage customers to use their standby generation in combination with demand response tariffs have been unsuccessful. Customers apparently do not feel there is sufficient financial benefit to justify the incremental operating and maintenance expenses or are reluctant to use their standby generation for anything other than sustaining critical loads during utility outages.

LG&E and KU do not believe the ability of the distributed generation to impact peak system demand will be significant. The availability and reliability of customer owned generation at the time of critical need is questionable. Also, customers have shown little interest in developing or utilizing on-site generation for this purpose.

Q. If the commission were to establish a statewide interconnection standard, what should be included in the minimum requirements?

A. IEEE 1547 should form the basis for the minimum interconnection requirements for each utility. Each utility will have to provide additional specifications to apply IEEE 1547 to the particulars of their distribution system and internal processes. In addition to IEEE 1547, other relevant industry standards the National Association of Regulatory Utility Commissioners (NARUC) recommends include:

- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- NFPA 70 (2002), National Electrical Code
- IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers
- IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors
- IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits
- IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits
- ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic
- Control in Electrical Power Systems

In addition to technical requirements, the Commission should also consider adopting standards defining the roles and responsibilities of both the utility and the interconnected customer to ensure consistency. At a minimum, these standards should define the responsibilities of each party including who should incur the various costs associated with the interconnection. Other requirements might include setting limitations on the maximum size of interconnected resources, establishing minimum technical standards for protective equipment, control and metering, defining timelines for various steps involved in the interconnection process, setting standards for inspection and maintenance of customer and utility owned protective equipment, etc.

Q. Can a reasonable program be developed to take advantage of customer owned open transition standby generation in case of a dire emergency? If yes, describe. If no, explain why not.

A. Based on customer response to programs for closed-transition customer-owned generation to this point, it is not believed that a reasonable program can be developed to encourage customers to make available conventional open transition (break before make) standby generation in the event of an emergency. From a practical standpoint, the size of customer owned generation varies greatly, is of questionable reliability, and in most cases could not be made available quickly enough to respond to emergencies. To utilize this generation in its present form would require two service outages (switch to generation, switch back to utility service) which the majority of customers would find unacceptable. Generation of this nature is also typically sized to handle only a portion of the customer's loads, in particular critical needs and processes. To be acceptable to the vast majority of customers the generation would have to be substantially modified to allow parallel connection to the utility grid so that no outage or reduction in demand was necessary. The addition of a large number of smaller, grid connected generators would present the utility with operating and safety challenges.

The cost for customers to convert standby generation for parallel operation with the system grid and/or under control of the utility would vary and may exceed any benefit that could be reasonably provided back to the customer.

Q. Should interconnection standards for Distributed Resources be limited in size? If so, at what level?

A. The size of a distributed resource that can be directly connected to the distribution grid without improvements will be limited by the existing distribution infrastructure. Even with improvements made at the customer's expense, a practical limit would be 10MVA for connection to the distribution grid unless approval is given by the grid owner. 10MVA is also consistent with the upper limit covered by IEEE 1547.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Michael Leake**, being duly sworn, deposes and says that he is Group Leader, Electric System Codes & Standards for E.ON U.S. Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Michael Leake

MICHAEL LEAKE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of May, 2006.

Randall J. Magallon (SEAL)

Notary Public

My Commission Expires:

Notary Public, State at Large, KY
My commission expires June 27, 2009