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March 23, 2006

RECEIVED
MAR 23 2006
PUBLIC SERVICE
COMMISSION

Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

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 please find an original and seven (7) copies of Louisville Gas and Electric Company's ("LG&E") and Kentucky Utilities Company's ("KU") Response to Information Requested in Appendix C of the Commission's Order dated February 24, 2006.

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Sincerely,

Kent Blake

Kent Blake

cc: Parties of Record

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,	)	CASE NO: 2006-00045
DEMAND RESPONSE AND	)	
INTERCONNECTION SERVICE	)	

Response to Information Requested in Appendix C
Of Commission's Order
Dated February 24, 2006

FILED: MARCH 23, 2006

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission's Order dated February 24, 2006

Question No. 1

Responding Witness: Irv Hurst / Kent Blake / Greg Fergason

Smart Metering

Q-1. Provide a list of programs you offer at present or have offered at any time since the enactment of the Public Utilities and Regulatory Policies Act ("PURPA") that can be included under the definition of either time-based metering or demand response set forth in Section 1252 of EPAct 2005. Include a brief description of each program, the relevant tariffs (if applicable) and a cite to the Commission case number in which the program was approved (if applicable).

A-1.

Time Based Metering

Kentucky Utilities Company ("KU") once provided a program for off-peak water heating as a rider to either residential or general service. As the service evolved it provided a discount for electric water heating used after 8 p.m. and prior to 9 a.m. The service was discontinued pursuant to the resolution of Case No. 2003-00434.

The Commission initiated Administrative Case No. 203 to examine the standards provided for in the Public Utilities and Regulatory Policies Act of 1978. As a result of those hearings the Commission directed utilities to provide time-of-day pilot programs examining the effectiveness of rate structures providing for a demand pricing differential between on- and off-peak periods for their larger customers. Although the results of those pilots were not definitive, the Commission directed and approved LC-TOD and LP-TOD rates for commercial and industrial rate application, respectively, for Louisville Gas and Electric Company ("LG&E") in Case No. 8872. Similarly, KU's tariff includes LCI-TOD, for commercial and industrial uses, and LMP-TOD for mining uses, in Case No. 8915.

Both LG&E and KU are offering a Small Time-of-Day ("STOD") tariff as a result of the settlement agreement in Case Nos. 2003-00433 and 2003-00434. As a pilot program, the STOD rate provides an energy rate differential between on- and off-peak periods for smaller customers.

At various times both LG&E and KU have offered seasonal rates. The Commission approved eliminating them for KU in Case No. 2003-434. The Commission also approved LG&E's beginning to move away from them by eliminating LG&E's residential seasonal rate in Case No. 2003-433. Nonetheless, LG&E still incorporates a seasonal rate differential in its power schedules that are available to commercial and industrial customers. These schedules incorporate a higher charge during the four summer months than the other eight months of the year.

Demand Response

LG&E and KU consider demand reduction and energy conservation programs in evaluating lowest cost options as part of our Integrated Resource Planning process. As a result, LG&E and KU have offered residential and small commercial customers the "Demand Conservation" demand response program since 2001. Demand Conservation, which was approved in Case No. 2000-00459, is designed to reduce critical summer peaks by cycling participants' air conditioning systems, electric water heaters and pool pumps. Participating customers are offered an annual incentive for each qualifying appliance. Program costs are recovered through a Demand-Side Management ("DSM") surcharge applied to the customer classes served by the program.

There are currently in excess of 80,000 devices connected to Demand Conservation switches, resulting in demand reduction potential of approximately 90 MW on days when the temperature reaches 97 degrees.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission's Order dated February 24, 2006

Question No. 2

Responding Witness: Irv Hurst / Kent Blake / Greg Fergason

Q-2. Provide a general discussion of the types of time-based metering or demand response programs that are possible using existing technologies and a specific discussion on which of these programs, if any, are feasible for current implementation in Kentucky.

A-2. There are numerous time-based metering options available, ranging from very simple seasonal rates that yield questionable demand response to complex systems offering two-way communications and hourly pricing. Low energy costs in Kentucky are a major consideration in evaluating potential programs from economic and customer acceptance perspectives. In fact, because of Kentucky's low rates, programs that work in other states may not be viable in Kentucky. Additionally, the significant differences between residential and small commercial customers compared to larger power users necessitate considering them from different perspectives.

Residential and Small Commercial

- Simply offering different rates in winter and summer would qualify as time-based pricing without a need for smart meters or any other new technology. For example, it is possible that raising the cost of electricity in the summer would send a price signal resulting in customers' reducing demand; however, such demand savings may not materialize if customers do not see seasonal rates as a pricing signal (due to inadequate price differentials), particularly if customers use budget billing to reduce seasonal billing spikes. A difficulty of seasonal rates is that they do not address critical peaks during any given day. Moreover, the difference between seasonal prices and ordinary prices may not be significant enough to impact usage patterns.

- Demand control switches attached to air conditioning units and other high electric-usage appliances are currently in use by LG&E, KU, and other utilities in Kentucky. Such switches capture demand savings without the need for smart metering technology. These programs are cost effective and are operating successfully.

LG&E is currently developing a new DSM pilot program that utilizes time of day pricing with a real-time component. The currently planned program for residential and small commercial customers will utilize smart metering, programmable thermostats, and a variable rate structure that would include different prices based upon time of day and a critical peak price (real-time). Additionally, both devices will be equipped with a radio receiver enabling the utility to activate critical peak pricing at the meter and automatically to adjust the thermostat to the customer's chosen temperature settings during the critical period.

This type of program offers numerous benefits as it appears to be cost effective and sends strong pricing signals, yet it also provides customers flexibility and control based upon their tolerance levels and desire to lower energy costs.

- Utilization of a variable rate structure can be taken to an even higher level than that described above by implementing additional technology such as smart metering with two way communications capability (such as cellular, phone line and power line carrier) and hourly rate capability. The cost of the technology would be significantly higher and would be more difficult to justify economically unless it was coupled with another initiative such as automated meter reading to help offset the costs. Additionally, most residential and small commercial customers have not expressed an interest in developing the level of energy expertise needed to benefit from hourly pricing.

Large Commercial and Industrial

Large commercial and industrial customers are better candidates for technologies enabling two-way communications as described above and for hourly rates because their greater usage and energy costs create an incentive to develop a much higher level of energy expertise and may make economic justification of the technology more realistic. Demand Side Management programs for large commercial and industrial customers are difficult to implement because each enterprise's energy needs are different, making standardized solutions unworkable. Additionally, industrial customers have been resistant to paying a surcharge that may be utilized to help reduce their competitors' costs.

**KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY**

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission's Order dated February 24, 2006

Question No. 3

Responding Witness: Irv Hurst / Kent Blake / Greg Fergason

Q-3. Provide, in narrative form, with all relevant calculations, work papers and assumptions included, what you see as the potential impact of implementing the Smart Metering standard included in Section 1252 of EPAct in Kentucky. At a minimum, the response should address the costs of implementation, financial impact on the utility, who should bear the costs of implementation, and possible rate making and rate treatment issues.

A-3. The impact of implementing the Smart Metering standards included in Section 1252 of EPAct, especially cost of implementation, financial impact, and customer response, will vary greatly depending on the design of the rate structure and the technology necessary for metering and billing. Residential and small commercial customers will have difficulty in adopting or responding to rate structures that are too complex or that do not send a significant and known price signal. These customers have been found generally less likely to alter their consumption patterns.

On one extreme, a time differentiated rate that is seasonal in nature, with higher rates in the peak months, would not require metering changes or investments in technology. Some modifications to billing systems might be necessary. LG&E and KU believe customers do not respond to this type of pricing signal with meaningful demand response.

On the other extreme, real-time pricing, where rates might vary on an hourly basis, would likely create significant costs for metering, meter reading, translation of interval metering data, and billing systems. Though a real-time rate structure may increase the potential for demand response, the complexity and uncertainty of prices would not lend themselves to a high level of customer participation in the residential and small commercial market. Customers may have difficulty in changing usage patterns with the frequency necessary to take advantage of the rate.

Residential and Small Commercial

Considering the costs of implementation, Kentucky's climate, and low prices for electricity, time-of-use ("TOU") or critical peak pricing ("CPP") options could have costs and benefits that may be better suited to demand response, especially for residential and small commercial customers. Both rates have pricing that is known, including a time-of-use component, without the complexity and uncertainty of hourly prices. The critical peak pricing option adds a fourth real-time pricing component that could be used to send a strong pricing signal to the customer during periods of highest demand and cost.

Time-of-use rates have been implemented by various utilities for residential and small commercial customers, sometimes on a large scale with a high number of participants. (For example, Niagara Mohawk had in excess of 30,000 customers on TOU rates in the early 1990's.) Although these customers initially respond to the pricing signal of the time-of-use rate by adjusting usage patterns, there are several shortcomings to this approach. Generally, the pricing signal (the difference between the lowest price and the highest price) is not strong enough and the customer must be proactive in shifting energy use. In many cases, customers' response decreased over time due to the ongoing need for their active participation in matching energy usage with pricing tiers.

LG&E and KU are aware of, and have reviewed, the various pricing/demand response programs and pilots carried out by utilities over the last decade. Critical peak pricing, which, with proper rate design, combines the simplicity of the time-of-use rate with a strong pricing signal for those top hours in the load duration curve where demand and cost are highest, may have the best potential for success. Considering that cooling, heating, and water heating make up the largest percentage of energy use and demand for residential and small commercial customers, and that these customers are not likely to be willing to actively shift the usage in these categories over the long term, this rate design should be coupled with programs that assist customers and employ technologies that automate these usages. Technologies including programmable, communicating thermostats that can adjust cooling and heating settings based on price signals, and automated control of water heating and other larger loads, will allow the customer to change usage patterns that result in reduced peak demand and the shifting of usage to lower cost periods.

LG&E and KU's 2005 Joint Integrated Resource Plan contained an analysis of this type of rate structure, including the enabling technologies for metering and automation of these larger energy using devices at the customer premises. The results of this analysis indicate that a critical peak pricing rate, with a companion Demand Side Management program to provide enabling technology for the customer premise, may be cost effective. Below is a summary of the costs associated with the implementation of this rate and DSM program on a per customer basis:

Cost to provide metering and CPP rate	$220
Cost of DSM program and enabling technology	$600

The IRP assumed that the participating customer would pay an incremental monthly customer service charge that would include the incremental cost of the smart meter, additional meter reading cost, and a portion of the DSM enabling technology. Excluding the customer costs which are included in the customer service charge, the DSM cost per participant was estimated to be $491.

There would also be significant costs associated with changes to the Customer Information System ("CIS") and the many related sub-systems.

Cost Allocation and Recovery

Understanding that the cost of implementing any program can vary greatly makes addressing concepts difficult and potentially misleading. However, whatever the cost of implementing a program, the financial impact on a company and its customers must be a net reduction in costs or the program has failed in its intent. In this case the intent is to reduce strains on the generation, transmission, and distribution systems sufficiently to justify increased metering and customer related costs. Ultimately, the customers will reap or bear at least a portion of any program's net benefit or cost.

But not all customers should bear all the net costs or benefits of a smart metering program, at least directly. Direct customer-related costs, such as metering, should be borne by the customers in the program. Similarly, since such customers theoretically are altering their usage pattern to impose lower cost on the system, the rate structure applied to that program should reflect the lower cost. Indirect cost such as the cost associated with modifying a customer information system or billing system may be socialized over a wider customer base. The program is available to the wider customer base and those customers stand to benefit from cost containment which would have been spread over the wider customer base had those costs been incurred.

A crucial component of any potentially successful smart metering program will be unbundling costs sufficiently for a customer to receive a proper price signal, assuming such signals can exist in adequate magnitudes to result in the desired customer response. Creating the proper pricing signal may prove difficult, at least in part because customer-related costs are not time related. Moreover, energy costs typically do not have the variation to change customer consumption patterns. Where such energy costs may vary in such magnitudes it should be noted that the variation may reflect decisions in least-cost generation options, gas instead of coal. As such it is a demand response we are seeking, not an energy one. Therefore it is the unbundled demand response which should provide the signal to the customer.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission's Order dated February 24, 2006

Question No. 4

Responding Witness: *Butch Cockerill / Irv Hurst / Kent Blake /Greg Fergason*

Q-4. Provide a general discussion of what you perceive to be the pros and cons of implementing a Smart Metering standard in Kentucky and the policy issues that you believe the Smart Metering standard presents for the Commission.

A-4. The fact that LG&E and KU are low cost producers creates a difficulty concerning time-differentiated pricing, particularly with respect to residential and small commercial consumers. In short, the time-period price differentials simply may not be great enough to encourage a shift in consumption patterns and still reflect the cost of service analysis typically accepted by the Commission.

There are several potential "pros" to smart metering in Kentucky from a DSM and usage pattern perspective. First, critical peak pricing can be one of the lower cost options for meeting future capacity needs by lowering peak demand, decreasing need for additional peaking units and the need to purchase costly off-system power.

Second, smart metering, at least in theory, provides customers the opportunity to voluntarily shift usage and reduce energy costs, which may help improve customer satisfaction as they have more choices about their energy buying needs. As (and if) customer behavior actually changes due to smart metering, namely by shifting usage from higher priced peak periods to off peak periods, system load factors should improve, providing a third "pro" and allowing LG&E and KU to operate their generation assets more efficiently.

There are also several potential "cons" to smart metering. First, over the short term, depending on the rate structure the Commission ultimately chooses, smart metering may be more costly to non-smart-metered customers if start-up costs are recovered from all customers and not smart-metered customers only. Second, there exists a risk of low customer acceptance or dissatisfaction if programs do not meet their expectations. Smart metering will result in increased complexity of billing for company and customer. Meter costs, as well as meter reading costs would increase. There would also be significant costs associated with changes to the Customer Information System and many related sub-systems.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission's Order dated February 24, 2006

Question No. 1

Responding Witness: Richard Bumann / Kent Blake

Interconnection

Q-1. Provide, in narrative form, with all relevant calculations, workpapers and assumptions included, what you see as the potential impact of implementing the Interconnection standard included in section 1254 of EPAct in Kentucky. At a minimum, the response should address the costs of implementation, financial impact on the utility, who should bear the costs of implementation, and possible rate making and rate treatment issues.

A-1. The financial impact on LG&E and KU of implementing the EPAct Interconnection standard should not be significant if the number of interconnection requests does not overburden present staff levels. Each request will require some level of review varying from a minor review to a significant study depending on the size, type, and location of the interconnected supply. Because several tariffs are already on file such as SQF (Small Qualified Facilities) and LQF (Large Qualified Facilities) that can require interconnection to the distribution system, some familiarity with the necessary technical requirements has been established and template interconnection documents already exist.

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. Cost to the serving utility should not be a factor because, with the exception of small or simple interconnections such as net metering (which require a minimum level of review), the interconnecting customer should bear the majority of associated costs. At a minimum, this should include any costs for:

- 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 (DG)

- Protective equipment required at the interconnection point provided by the utility

New or modified tariffs may be required to accommodate interconnecting customers or to encourage customers to interconnect potential DG sources in parallel with their utility source to reduce peak demands. LG&E and KU do not believe the ability of the DG to impact peak system demand will be significant. The ability to generate from alternate energy sources such as hydroelectric, biomass, wind, thermal and solar is limited in the state of Kentucky. Other sources of generation may not prove economically attractive or even feasible.

Not much interest has been shown in the area of DG as of this time. Even customers with significant existing generation (such as standby generation) have been reluctant to utilize it for anything other than their own emergency back-up. Most standby generation is designed for short term usage with fuel and maintenance issues limiting the amount of run time. However, with modifications this standby generation could be utilized for longer periods of time if economically beneficial to the customer. If so, this could create a demand for additional interconnections.

There is a potential for DG to lower the total cost of meeting electricity demand, including production, transmission, and distribution costs. In reality, however, DG can result in shifting cost from DG customers to non-DG customers because most utility costs are recovered through bundled rates based on metered service. Unless care is taken the DG customers are over-compensated for their load reduction shifting to non-DG customers, or over paid for energy delivered to the system again shifting cost to the non-DG customers. Such customers should pay for the stand-by service they require and be compensated for no more than the utilities' avoided cost.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission's Order dated February 24, 2006

Question No. 2

Responding Witness: Richard Bumann / Charles Freibert

Q-2. Provide a general discussion of what you perceive to be the pros and cons of implementing an Interconnection standard in Kentucky and the policy issues that you believe the Interconnection standard presents for the Commission. Include discussion of the issues that must be addressed to comply with IEEE 1547.

A-2. The are several "pros" to implementing an interconnection standard. For example, such a standard could encourage the addition of distributed small power installations that, if reliable and present in sufficient quantity, could slightly reduce peak system demands and delay capacity additions. It could possibly encourage environmentally friendly or high-efficiency alternate energy development such as waste based generation, wind, solar, biomass, Combined Heat and Power (CHP), and others.

Standardizing interconnection practices in conjunction with LG&E's and KU's current tariffs for interruptible rates could also encourage customers to install or utilize existing supply sources to move a portion of their load to an interruptible rate. This could help free additional capacity on peak days and may become attractive for a broader range of customers because they could take advantage of interruptible rates without sacrificing production. The present limits on interruptible capacity are probably too high for most customers to take advantage of using existing energy sources such as standby generation under current interruptible rates. Almost all existing standby generation would require the addition of protective equipment to run in parallel with the utility system, and the effectiveness of connecting standby generation to the grid may be limited by economics or air quality issues.

"Cons" include the limited potential for the development of DG in the Kentucky area from solar, thermal, hydro, biomass, and wind energy. Safety would also be a primary concern of interconnected systems, as well as customers' maintenance of their interconnected systems. The addition of DG could result in longer restoration times if it becomes standard practice physically to isolate (visibly open) DG sites from the system before restoration work is performed.

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

Also of concern is the cost to install safe and reliable switching to connect DG to the grid and to provide remote control of these switches to ensure proper utilization during peak periods.

Other concerns include the potential to cause utility system disturbances that adversely impact the system from switching transients, poor power factor, or voltage variations. The addition of DG sites could also require system improvements to handle the capacity of a DG site depending on its size and location on the system, possibly for little real benefit to the utility. Furthermore, DG should not be allowed in network secondary areas (e.g., downtown Louisville) because of the inability of protective systems to respond to reverse power flow.

Policy issues:

There are several policy issues that will confront the Commission concerning an interconnection standard. First, there will need to be tariff development or modification to accommodate or encourage DG beyond what presently exists. Second, there is the question of whether the customer or the utility -- or both -- should furnish protective equipment or bear the cost of interconnection, including system planning studies, system enhancements, and special metering. Third, the Commission will need to confront the issue of safety of interconnected facilities, as well as the reliability of interconnected DG and its impact on power quality. Fourth, the Commission should establish requirements for maintenance of protective equipment of interconnected DG and determine who is responsible for paying those costs. Fifth, there is the question of limiting the capacity of DG for interconnection to a radial distribution system. Sixth, the Commission should establish standard time requirements to accommodate interconnection based on the type and capacity of DG seeking to interconnect. Seventh, there will need to be limitations on DG alliances with existing customers when the customers utilize existing distribution systems as a delivery path. Eighth and finally, the Commission should evaluate the potential impact of any requirements to incorporate DG in system planning and capacity planning.

IEEE 1547:

LG&E and KU see no significant issues with utilizing the IEEE 1547 standard as the basis for interconnection standards. Presently, LG&E/KU interconnection standards are based on IEEE 1547. However, IEEE 1547 is only one of the relevant standards that are applicable to interconnecting DG to utility systems safely. Other standards as recommend by the National Association of Regulatory Utility Commissioners (NARUC) 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

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission's Order dated February 24, 2006

Question No. 3

Responding Witness: Kent Blake / Michael Leake

Q-3. Identify any customer with on-site generation that is currently connected to your distribution system. Provide the customer's maximum demand in 2005 and current generating capacity.

A-3. Tariffs currently exist for Small and Large Qualified Facilities, Net Metering, and Load Reduction, all of which are essentially interconnected DG. The customers under these tariffs are:

- Paris is a wholesale customer with connected generation of 12 MW
- The Mother Ann Lee Hydroelectric Station is a small, 2 MW hydroelectric plant expected to utilize KU's electric system to sell power to Salt River Electric
- Weisenberger Mill Company is a small hydroelectric net producer who contracts to operate a 50 KW water-powered induction generator
- APSI is a net metering customer with an estimated 2.2 KW connected to the system

An unknown number of other customers have "open transition" switched generation that operates entirely separately from the distribution grid at all times. This is the more conventional type of standby generation and is far more common, often installed without utility knowledge. Records do not exist for all the customers that have open transition switched generation but they include hospitals and medical centers, data and call centers, and other many service critical facilities. Closed transition switched generation is capable of synchronizing with the utility source and running in parallel. Typically this generation is interconnected to the system momentarily for testing and can range from small to large capacity generation. Because they are only momentarily connected to the utility system, they do not require a special tariff, although they do require special protective equipment as specified in IEEE 1547. In order to run in parallel with the utility grid for longer periods of time, changes to the existing metering and protection systems would be required. The Companies are aware of approximately 70 MW of generating capacity so connected to their system.