LG&E ENERGY

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RECEIVED
APR 27 2006
PUBLIC SERVICE COMMISSION

April 27, 2006

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 Commission Staff's Second Information Request dated April 13, 2006.

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

Sincerely,

F. Howard Bush

F. Howard Bush
Manager, Tariffs/Special Contracts

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

APR 27 2006

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

Response of Louisville Gas and Electric Company and Kentucky Utilities Company to the Commission Staff's Second Information Request Questions 21-27 Dated April 13, 2006

FILED: APRIL 27, 2006

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission Staff's Second Information Request
Questions 21-27

Question No. 21

Responding Witness: Kent Blake

Q-21. Refer to page 2 of 2 of the response to Item 1 in the "Smart Metering" requests in the commission's February 24, 2006 Order. The first full paragraph on the page refers to the Commission having approved the elimination of seasonal rates for KU in Case No. 2003-00434 and LG&E's beginning to move away from seasonal rates in Case No. 2003-00433.

a. These changes were approved as part of the unanimous portions of the settlement agreements reached in these two rate cases. To what extent, if any, do LG&E and KU believe that those agreements establish any precedent or bind the parties, or the Commission, for future cases?

b. Explain in detail the basis for any decision by LG&E and KU to move away from seasonal rates.

A-21. a. LG&E and KU included references to Case No. 2003-00434 and Case No. 2003-00433 in an effort to be responsive to the data request in Item 1 in the "Smart Metering" for "a cite to the Commission case number in which the program was approved (if applicable)".

With regard to precedential value, Section 4.12 of the Settlement Agreement in the above cases states, "This Settlement Agreement shall not have any precedential value in this or any other jurisdiction."

Section 3.13 of the Settlement Agreement is the specific section of that agreement which addresses the elimination of seasonal rates and states, "The signatories hereto, including the AG, agree that LG&E shall eliminate the seasonal rate structure for Rate RS and shall implement a non-seasonally differentiated rate structure for Rate RS. Nothing contained in this Section shall preclude the Utilities from making a future proposal for a seasonal rate structure."

The Commission's June 30, 2004 Order in Case No. 2003-00433 did express some reservations about this aspect of the Settlement Agreement and placed certain requirements on LG&E as follows:

"Electric Residential Rate Design

The parties have agreed to eliminate LG&E's seasonal residential electric rates. Historically, LG&E's residential rates have been set at higher levels during the peak summer months of June through September than during the rest of the year. Due to the impact of residential air conditioning use on LG&E's summer peak demand, this rate design was implemented to encourage conservation during the summer peak season. While the Commission does not object to eliminating this peak season differential, we are concerned that it might have an adverse impact by causing LG&E's peak demand to increase. Therefore, we find that LG&E should be required to monitor its summer demand, beginning July 1, 2004 and continuing through September 30, 2006 to ascertain the impact on its demand, if any, resulting from this rate design change. We also find that LG&E should, within 90 days of the end of this monitoring period, prepare a brief analysis and report on the results of its monitoring.

LG&E should compare the actual growth in its residential summer demand to the growth it has forecast for its residential summer demand. While many factors can affect the difference between actual and forecast demand growth, LG&E should determine whether any unanticipated growth is the result of the change to a single year-round energy rate for residential customers. The Commission will convene an informal conference with LG&E within 90 days of the end of this monitoring period to facilitate an informal review of LG&E's analysis. The Commission will, at that time or earlier if conditions warrant, determine the need to evaluate the impact that this rate design change may have on LG&E's summer peak demand and investigate whether the seasonal residential rates should be re-implemented."

b. The seasonal rate structure for standard residential service (Residential Service Rate RS) was eliminated in LG&E's 2003 rate case (Case No. 2003-00433) as a part of negotiated settlement. Seasonal rates were retained for other major rate schedules, including General Service Rate GS, Large Commercial Rate LC, Large Commercial Time-of-Day Rate LC-TOD, Large Power LP, and Large Power Time-of-Day Rate LP-TOD. In its Application in Case No. 2003-00433, LG&E proposed to retain the seasonal rate structure for Rate RS. In that proceeding, the Attorney General proposed to eliminate the seasonal rate structure for residential service. LG&E, the Commission Staff and other parties agreed to eliminate the seasonal rate structure for the residential rate class as a part of a negotiated settlement in that proceeding. Other than the elimination of the seasonal rate structure for residential

c. customers as a part of a negotiated settlement, there has not been a decision by LG&E to move away from seasonal rates.

KU's rates were never seasonally differentiated; therefore, there has not been a decision by KU to move away from seasonal rates.

KU and LG&E understand the position held by some of the parties in their last rate cases to be that seasonal rate differentials are not an effective way to send price signals to residential customers because they do not provide the price signal necessary to elicit the desired *demand response* and that an energy price differential may not be the appropriate vehicle for obtaining a demand response.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission Staff's Second Information Request
Questions 21-27

Question No. 22

Responding Witness: Greg Fergason / Kent Blake

Q-22. Refer to page 2 of 2 of the response to Item 2 in the "Smart Metering" requests in the Commission's February 24, 2006 Order. The first paragraph on the page refers to a new DSM program that LG&E is developing that utilizes time-of-day pricing with a real-time component.

a. Describe the referenced program. If the planning process is in an early stage, provide as much information as is available.

b. What is the timetable for implementing that program?

c. Regardless of the responses to 22(a) and (b), explain whether or not it is appropriate for the commission to consider the referenced program in this proceeding.

A-22. a. In its Final Order dated June 30, 2004 in Case No. 2004-00433, the Commission approved the unanimous resolution of a substantial number of issues as filed by the parties in the document entitled "Partial Settlement Agreement, Stipulation and Recommendation" ("the Settlement"). One such provision as outlined on page 9 of the Final Order is as follows:

> "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."

Specifically, Section 3.6 of the Settlement details the requirements for the program as follows:

> "The signatories hereto, including the AG, agree that LG&E shall establish a real time pricing ("RTP") pilot program for LG&E's electric customers. The term of the program shall be

> three (3) years. In each year, up to fifty (50) customers under Rate R and up to fifty (50) customers under Rate GS shall qualify for the program. During the second year of the program, LG&E shall propose to the Commission detailed plans, terms and conditions for the inclusion of customers under Rate LP in the program, such inclusion to take place during the second year of the program. Rate LP customers shall be eligible for participation in the program during the second and third years of the program in accordance with the Commission's approval of LG&E's proposal for inclusion of Rate LP customers. The customer-specific costs shall be recovered through a facilities charge incorporated into the applicable customer charges during the first six (6) months of the RTP pilot program. After six (6) months, the Utilities shall evaluate the level of participation in the pilot program and consider modifying the treatment of such customer-specific charges to encourage participation in the RTP pilot program. The non-customer-specific costs of modifying LG&E's customer billing system to bill customers under the RTP pilot program will be recovered pursuant to the RTP pilot program through a charge per kWh billed to customers taking service under Rates R, GS and LP in the same manner as the Demand-Side Management ("DSM") Cost Recovery Component of LG&E's DSM Cost Recovery Mechanism. After the end of the three year term, LG&E will evaluate the performance of the RTP pilot program for the following purposes, including, but not limited to: (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 program as either a permanent demand-side management program or as a standard rate schedule. LG&E shall file a report with the Commission describing its findings within six months after the first three years of implementation of the RTP pilot program. The RTP pilot program shall remain in effect until the program is modified or terminated by order of the Commission."

After the Commission issued its Final Order on June 30, 2004, LG&E began to review and investigate what was needed to implement a successful RTP program. The logical first step was to review the programs already in place at other utilities. During the latter half of 2004, LG&E held detailed discussions and conducted an extensive review of programs offered by other utilities that had implemented time–based rate schedules and compared those programs to those which included the installation of "smart meters" (meters that record usage at pre-set intervals). It was determined that a variable pricing program used in conjunction with smart meters, as implemented by Gulf Power (based in Pensacola, Florida) would be the most appropriate and beneficial model for a pilot program at LG&E. This pilot would include the establishment of defined prices set during the various periods of a day -- designed with two or perhaps three "non-critical" time periods defined by day and hour -- with a critical time frame determined at which conservation would be most desired. The price at this time period, the "critical price," could approach four to five times the average non-critical price with the ultimate goal of leveling out the low and high peak demand periods in a given year.

In early 2005, LG&E produced load profile data and met with the manufacturers of the various enabling technologies (e.g. smart meters) to further clarify the viable alternatives for supporting program development. In mid-2005, LG&E produced the production cost profiles necessary to allow the initial rate design for the various time periods outlined above. In late 2005, LG&E performed initial rate design reviewed the rate design to ensure revenue neutrality, drafted preliminary tariffs, and tested metering and communications equipment.

Throughout 2004 and 2005, LG&E also addressed strategic issues regarding pilot implementation. Two key issues include (i) the integration of the RTP with DSM and (ii) customer billing for RTP participants. For the former, LG&E determined that the RTP program filing should be coordinated with a DSM program filing, to align the elements of each program in order to maximize the effectiveness of customer participation. For the latter, LG&E determined that full scale billing system technology/programming changes should not be proposed during the pilot due to the high degree of complexity and cost of such changes and the uncertainty of the ultimate usefulness of such changes. Rather, LG&E concluded that the preferred option would be to utilize a manual billing process. Should the pilot results indicate that a full scale implementation of RTP is prudent and should the Commission approve implementation, modifications to the billing system would be made at that time.

LG&E has been investigating a new DSM pilot program to complement the RTP described above that utilizes time of day pricing with a real-time component. 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.

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. Additionally, the difference between the highest price period and the lowest price period has not been a sufficiently strong price signal. The two main premises of the proposed LG&E program design include an additional "critical", real time price component which would be activated during the same conditions that our load control devices are activated. Also, 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 a residential customer's load, temperatures could be set to maximize usage in lower priced periods and to minimize usage in higher priced periods. Water heaters and other large use appliances such as pool pumps, could be shut off during higher priced periods. Automation of the usage of these loads would allow the customer to shift usage without manual intervention on a daily basis. Customers would also be provided a TOU meter capable of receiving a signal to indicate when usage was in the critical, real time period.

Below is an example of the TOU time periods and the pricing structure that might be utilized:

June through September

	LOW	MEDIUM	HIGH
Weekdays	9 P.M. – 10 A.M.	10 A.M. – 1 P.M. 6 P.M. – 9 P.M.	1 P.M. – 6 P.M.
Weekends	6 P.M. – 1 P.M.	1 P.M. – 6 P.M.	

October through May

	LOW	MEDIUM	HIGH
Weekdays	10 P.M. – 8 A.M.	8 A.M. – 6 P.M.	6 P.M. – 10 P.M.
Weekends	10 P.M. – 6 P.M.	6 P.M. – 10 P.M.	

Customer Charge: $10.00 per month

Plus an Energy Demand Charge:

Low Cost Hours	3.268¢ per KWH
Medium Cost Hours	4.638¢ per KWH
High Cost Hours	15.008¢ per KWH
Critical Peak Hours	36.248¢ per KWH

Critical peak hours would be during times of high system demand and pricing, generally the same time periods that load control devices are activated, with additional critical peak periods during the winter months. Generally, critical peak periods would typically last for 2 hours with an annual maximum of 80 hours.

Customers can know energy prices for 99% of the hours in a year while also having a strong pricing signal during periods of highest demand and cost, the critical periods. The advanced thermostats are capable of showing the customer what pricing tier is currently in effect, and can also notify the customer of a pending or current critical peak period. By automating temperature settings with the thermostat and shutting off water heaters, customers can shift usage out of the periods of highest cost and system demand, 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 more energy being shifted outside the highest cost and demand periods for additional savings.

b. No specific timetable was set for implementing the Real Time Pricing ("RTP") program. However, development of the program had progressed to the point where the Company was prepared to file in a matter of months.

c. The Company believes it is appropriate for the Commission to consider RTP in this proceeding. Uncertainty about certain elements of the new law have given LG&E pause regarding the plans to implement the RTP pilot as outlined above.

   The Company's initial interpretation of the new law was that the utilities must offer some form of TOU rates within 18 months from the enactment of the EPACT (August 2005). The new law does not specifically define TOU rates, however it does describe potential TOU rates including a standard TOU rate, critical peak pricing, real time pricing and peak load reduction programs. This would mean that by February 2007, TOU rates must be offered by utilities to all customers in all rate classes. Subsequent review and consultation indicate that the "18 month from enactment" specification is a recommended standard but may not be a legal requirement.

   The EPACT also directs state commissions to investigate whether TOU rates are appropriate and to determine whether the state commissions want to permit TOU rates. This determination must be completed by February 2007. A strict interpretation of the language may also indicate that by February, 2007, LG&E and KU must implement a TOU program available for all customers in every rate class, but the state commissions have until February 2007 to determine if such a program is appropriate for Kentucky.

   Legal requirements and timing issues related to TOU rates need to be resolved quickly as these statutory assignments could have a significant impact on the type and coverage of any real time pricing program. Making TOU rates available to all customers at both LG&E and KU by February 2007 would be an extraordinarily time-consuming and costly initiative. In addition to major modifications to both Companies' meter reading and billing systems, existing meters would have to be replaced with smart metering which would result in stranded investment in meters. Additionally, expensive meter reading and communication equipment would have to be upgraded.

It is LG&E's opinion that the EPACT language allows the Commission to reject a time-based rate and smart metering requirement, providing they have conducted a study to support such a rejection. It is also believed that the Commission has the option to modify the type, coverage and time-table for any time-based rate program

LG&E believes that given the uncertainty of EPACT it would be in our customers best interest for the Company to delay implementation of a RTP pilot program until the Commission issues an interpretation of the Energy Policy Act of 2005 ("EPACT") and its impact on Kentucky's electric utilities, as it pertains to Section 1252, pursuant to this Administrative Case.

It is because of the Commission's consideration of this issue that the Company believes it is prudent to delay implementing RTP until the Commission reaches a conclusion to this proceeding. To not do so could result in a program in place that would not satisfy parameters that may be set by the Commission, thereby wasting resources. Therefore the Company plans to await further direction by the Commission prior to initiating the RTP described herein.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission Staff's Second Information Request
Questions 21-27

Question No. 23

Responding Witness: Greg Fergason

Q-23. Refer to page 2 of 2 of the response to Item 2 in the "Smart Metering" requests in the Commission's February 24, 2006 Order. The last paragraph on the page refers to the difficulty of implementing DSM programs for large commercial and industrial customers due to the differences between these customers, making standardized solutions unworkable. What barriers, if any, prevent utilities from being involved in developing customer-specific DSM programs for these classes of customers? Explain the response.

A-23. Residential and small commercial customers have energy use systems that allow the Companies to develop mass market programs with a single program design and standardized technology that can fit the needs of a large number of customers and result in small DSM surcharges. Industrial and larger commercial customers have much more specialized energy use systems that require programs tailored to analyze these specific systems and provide individualized recommendations and solutions. Many of our largest users have in house expertise, or even energy management departments that are more capable of understanding their individual energy usage and needs than the Companies could achieve without very significant increases in resources, resulting in significant DSM surcharges.

The Companies have previously proposed DSM programs for industrial customers. As part of this program, customers were given the opportunity to "opt out" of DSM programming. Because a significant majority of these customers did "opt out" the program was not implemented. Reasons provided by industrial customers included their belief that they could best provide their own energy management, as well as a concern that a DSM surcharge may result in a company subsidizing their competitor.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission Staff's Second Information Request
Questions 21-27

Question No. 24

Responding Witness: Kent Blake / Greg Fergason / Robert Thomson

Q-24. Refer to page 1 of 3 of the response to Item 3 in the "Smart Metering" requests in the Commission's February 24, 2006 Order. The second paragraph in the response states that LG&E and KU believe that customers do not respond to time differentiated rates that are seasonal in nature with meaningful demand response. What is the basis for this belief? Explain the response.

A-24. Industry research has indicated that the long-term price elasticity of demand for electric residential customers is relatively limited. In the case of LG&E and KU, price response is further muted due to the relatively low cost of electricity in our service territory. However, as indicated in response to Q-21 (b), the Companies continue to evaluate the impact of seasonal rates. With regard to the response to Item 3, the Companies were merely referring to the different degrees on the scale of variable pricing programs that a utility could implement. The Companies believe it would be prudent to investigate a program such as the one described in our response to Q-22 herein to determine if this incremental step along that scale might prove to be more beneficial and cost effective. Such a pilot should provide valuable data with respect to short-term price elasticity of demand for residential and small commercial customers.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission Staff's Second Information Request
Questions 21-27

Question No. 25

Responding Witness: Greg Fergason

Q-25. The March 16, 2006 Courier Journal included an article that briefly described LG&E's offering of 2,000 programmable thermostats. Provide a detailed description of this program.

A-25. The Company's suppliers of load control switches have incorporated the load control radio receiver into programmable thermostats. These thermostats work in exactly the same manner as our currently deployed load control switches with an additional benefit enabling customers to use the programmability of the thermostat for additional savings through temperature setbacks year round.

We received an initial allotment of 2,000 thermostats that we targeted toward customer who use gas heating as a means of offering some assistance for high natural gas prices, while also enrolling those customers into our existing load control program. The programmable thermostat itself is the customers' incentive for participation rather than the annual $20 bill credit provided to customers equipped with standard load control switches.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission Staff's Second Information Request
Questions 21-27

Question No. 26

Responding Witness: Richard W. Bumann / Kent Blake

Q-26. Refer to page 2 of 2 of the response to Item 1 in the "Interconnection" requests in the Commission's February 24, 2006 Order. The second full paragraph on the page refers to customers with significant standby generation being reluctant to utilize this generation other than for their own emergency back-up use. Also refer to the response to Item 2 in the "Interconnection" requests relating to the discussion of customers with "open transition" switched generation.

a. Relative to each customer generator group identified above, to what extent have LG&E and KU inquired about and/or pursued the potential for having access to this generation at times of peak demand or extreme emergency on their systems? Explain the response.

b. Would LG&E and KU see any value in a program encouraging either customer generator group (through the provision of bill credits, for example) to utilize this generation voluntarily to meet their needs and free up utility resources during periods of peak demand or extreme emergency? Explain the response. If yes, describe what actions would need to be taken to allow for such a program.

A-26. a. LG&E and KU have offered multiple programs to provide access to customer-owned generation during peak demand and emergency situations. LG&E initiated its Interruptible Tariff in 1983. Similarly, KU began offering an Interruptible Tariff in 1983 which evolved into the Curtailable Service in 1994. Both Companies' tariffs offer a billing credit for a customer reducing load, upon the utility's request, either by reducing usage or by using customer-owned generation. The Companies have also offered a Load Reduction Incentive ("LRI") which began as a pilot program in 2000 and for which the Companies filed on August 1, 2006, an application to make it a permanent part of the tariff. LRI applies solely to load reduction through the use of customer-owned generation for which the customer receives a price quote at the time of the request by the utility. Although the response to the pilot program has been limited, the Companies believe in its potentially larger-scale benefit and its added appeal to customers relative to previous programs because the customer may elect not to respond to a particular utility request.

b. See the response to Q-26 (a).

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

ADMINISTRATIVE CASE NO. 2006-00045

Response to Commission Staff's Second Information Request
Questions 21-27

Question No. 27

Responding Witness: Richard W. Bumann / Larry Monday

Q-27. Refer to LG&E's and KU's response to Item 2 in the "Interconnection" requests in the Commission's February 24, 2006 Order, where LG&E and KU briefly reference their interconnections standards.

a. Describe the interconnection standards developed and utilized by LG&E and KU.

b. Do the current interconnection standards differentiate between small generators of 10 MVA and below, and those generators above 10 MVA? Explain the response.

A-27. a. Please see the attached primary and secondary distribution system interconnection guideline documents for the Companies. The interconnection standard was developed to quickly and consistently address customer requests for installing generation that would be operated in parallel with their utility service regardless of the duration of parallel operation. This document was intended to be flexible enough to apply to small net generators, co-generators or customers with closed transition standby generation.

Standby generation is only covered by this document if it is intended to be operated in a closed transition (make before break) switched mode. This document applies regardless of the duration of the parallel transition, however short duration transitions (less than 100 milliseconds) have substantially reduced protective requirements. The standard is based on the application of the IEEE standard interconnection requirements to the specifics of the LG&E and KU systems and covers interconnections from secondary voltages through 34.5 kV.

b. At the current time there are no limitations on the size of interconnected generation specified in the documentation and any limitations would be imposed on a case-by-case basis. The size of net generation connected to the distribution system could be restricted due to capacity limitations on the utility distribution system. While limitations will be unique to each application depending on the existing distribution infrastructure, 10 MVA would be a realistic upper limit for net generation connected to the distribution system. Additional protective requirements may also be imposed on net generators to prevent islanding in the event the utility source is lost.

Louisville Gas and Electric Company
Distributed Generation Guidelines
for
Primary Distribution System Interconnection

INTRODUCTION

A Distributed Generator (DG) is defined as any generator connected to the LG&E Energy Corp. Electric Power System (EPS) through a Point of Common Coupling (PCC). This manual is provided to assist in designing and/or selecting equipment that can be installed and operated in a manner that will ensure safe and reliable interconnected operation as required by IEEE 1547.

There are three types of circuits which connect the Company's generating stations with its substations and customers: (1) Transmission; (2) Primary Distribution; and (3) Secondary Distribution. Distributed generation can be connected, depending on its output voltage, size, and other characteristics, to anyone of these systems.

1. TRANSMISSION SYSTEM. This system is used, by the Company, to transmit large quantities of power to and from other utilities, and from its generation sources to its distribution substations. Some large industrial customers receive electric power directly from this system. The following voltages for interconnection are available:

    a. 69 KV, three phase, 3-wire
    b. 138 KV, three phase, 3-wire
    c. 345 KV, three phase, 3-wire

2. PRIMARY DISTRIBUTION SYSTEM. Some large commercial and small industrial customers are provided service at the available voltages in this system, which is shown below. This system is used, primarily, to transmit power to the Secondary Distribution System.

    a. 4160Y/2400 V, three phase, 4-wire
    b. 12470Y/7200V, three phase, 4-wire
    c. 13800 V, three phase, 3-wire
    d. 34500Y/19920 V, three phase, 4-wire

3. SECONDARY DISTRIBUTION SYSTEM. This is the system to which the majority of the Company customers are connected, including most served under the Company's residential rate. The following voltages are available for interconnection:

    a. 120/240 V, single phase,-3-wire
    b. 208 Y/120 V, three phase, 4-wire
    c. 240 V, three phase, 3-wire
    d. 480 Y/277 V, three phase, 4-wire
    e. 480 V, three phase, 3-wire

To which system a DG should (or can) connect, depends on the size of the generator, and on the proximity of the various systems with respect to the DG, in addition to other technical considerations. A DG should consult with the Company, prior to purchasing its equipment, to determine which system is appropriate for interconnection.

This particular guidebook only provides technical assistance to the DG that is planning to interconnect with the primary distribution system. Other guidebooks are available for those who would likely interconnect with the secondary distribution or transmission systems.

SEPARATE SYSTEMS

A separate system is defined as one so configured that there is no possibility of connecting the customer's generating equipment in parallel with the utility's system. For this design to be practical, a customer must be capable of transferring load between its generation source and the company source in a non-parallel mode. This can be accomplished by either an electrically or mechanically interlocked switching arrangement which precludes paralleling the two sources of generation.

> **NOTE: Any closed transition switching ("make before break"), even momentary if greater than 100 ms (0 ms for a secondary grid or spot network) per IEEE 1547 and LG&E requirements, is considered to be parallel operation. Any DG system utilizing a closed transition scheme must be designed and constructed in accordance with the design requirements for parallel operation as further defined in this document.**

If a customer is planning a separate system, the Company requires verification that the transfer scheme meets the non-parallel requirements. This is accomplished by submitting drawings to the Company for approval and, if the Company so elects, by field inspection of the transfer scheme. The Company cannot be responsible for approving the customer's generation equipment and assumes no responsibility for its design or operation. The only reason the Company reserves the right to approve the drawings and/or inspect the transfer scheme is to ensure that its personnel can safely work on Company equipment, and to ensure that other customers served by the same system will not be adversely affected by the separate system.

Most Uninterruptible Power Supply (UPS) systems do not specifically meet the separate system criteria, however if they are not capable of back feed (transfer of power to the utility), they will be classified as a separate system. If they can back feed, they must meet the requirements of the IEEE-1547 as-a DG, as well as the technical requirements for parallel operation.

THE FOUR BUY/SELL OPTIONS

There are four options the DG has regarding the purchase and sale of power with the Company:

1. The DG does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements.

2. The DG sells to the Company the energy and capacity it produces, but is not a customer of the Company.

3. The DG sells to the Company the energy and capacity it produces in excess of its total load, and purchases from the Company its net load requirements.

4. The DG sells to the Company the total energy and capacity it produces, while simultaneously purchasing from the Company its total load requirements.

Once a DG has selected one of the four options, and a written covenant has been executed, the DG can not change options until the signed agreement has expired or has been terminated by mutual agreement of the parties.

TYPES OF GENERATORS

There are three general classifications of power producing equipment: synchronous generators, induction generators, and static inverters. Any of these may be used by a DG, but there are different technical areas to address for each to ensure safe and reliable interconnected operation.

1. SYNCHRONOUS GENERATORS. This is the type of generator that most utilities, including the Company, uses to produce power. A synchronous generator does not have to rely on the utility system for its excitation. Therefore, a synchronous generator is capable of keeping a utility line energized even after the line has been isolated from other generating sources. The Company reserves the right to inspect the DG's facility

2. INDUCTION GENERATORS. An induction generator must inherently have the utility source to establish a magnetic field for generation. Depending on the DG's generator size, this can create a voltage problem. The Company may require the DG to install capacitors (and capacitor switching equipment) to limit the adverse effects of reactive power flow on the Company's primary distribution system capacity and voltage regulation. It should be noted, however, that the installation of capacitors for reactive power supply at, or near, an induction generator greatly increases the risk that the-induction generator may become self-excited if accidentally isolated from the Company's electrical system. The self-excited induction generator can produce abnormally high voltages which can cause damage to the equipment of Company customers. Over voltage relays can limit the duration of such over voltages but cannot control their magnitude because of the rapid voltage rise which occurs with self-excitation. Because of this, reactive power supply for large induction generators must be studied on an individual basis. In general, self-excitation problems are most likely in areas of low load density. As with large induction machines used as motors, the inrush current resulting from the starting (or synchronizing) of an induction machine used as a generator may cause an instantaneous voltage drop that can create problems for customers of the Company. For this reason, the Company must also study, on an

individual basis, the effect the starting (or synchronizing) of the DG's induction generator will have on system voltage.

3. INVERTER SYSTEMS. Reactive power supply requirements for inverter systems are similar to those for induction generators and the general guidelines for induction generators also apply to inverters. Inverter systems may also be capable of isolated operation. Self-commutated inverters have this capability by design. Line-commutated inverters could operate isolated if connected to rotating machines which provide the necessary commutation. The design and protection of inverter systems must address these possibilities of self-excited operation.

GENERAL DESIGN CONSIDERATIONS

1. The DG's installation must meet the IEEE 1547 Standard. The DG shall also meet all applicable national, state, and local construction and safety codes.

2. The DG that connects to the Company's primary distribution system must purchase, operate, and maintain the transformer (herein referred to as "inter tie transformer") that serves to step up the DG's generated voltage to that of the Company's primary distribution system. The Company's side of this transformer must be connected to conform to the circuit to which it is connected. An inter tie transformer may not be necessary if the DG's equipment generates at a primary distribution system voltage.

3. The DG is responsible for providing the necessary protection for its own system, as well as protecting against adverse effects, from its operation, to the Company's system. Where applicable, the DG will provide protection for the various electrical problems outlined in the RELAYING REQUIREMENTS section below.

4. The Company will install and own required revenue metering equipment. (See the METERING REQUIREMENTS section below.)

5. A manual load break disconnecting device will be installed by the Company at the point of the interconnection. This device will be controlled by the Company to ensure Company personnel can service Company lines and equipment safely. It will be of the type allowing Company personnel to visibly see the electrical break.

6. The DG shall provide adequate facilities for proper synchronization of its generator with the Company such that synchronism can be accomplished without causing undesirable currents, surges, or voltage dips on the Company's primary distribution system. The DR shall parallel with the Utility without causing a voltage flicker at the PCC greater than 5%. Either induction starting (if the inrush will not exceed allowable limits), automatic synchronizing, or manual synchronizing supervised by a synchronizing relay must be provided. The DG must never attempt to parallel its system with the Company's primary distribution system

when the DG's synchronizing facilities are malfunctioning or inoperative. Manual synchronizing without relay supervision is not permitted.

7. The DG shall provide means for automatically disconnecting its generator from the Company's primary distribution system for those occasions when the Company's primary distribution system becomes isolated from its source of generation, and for the proper resynchronization of its generator after such interruptions or isolations. Three phase automatic reclosing devices are installed on the Company's primary distribution system, thus the speed of the DG's automatic isolation equipment must be such as to disconnect its generation prior to automatic re-energization of the circuit by the Company. (This is discussed further in the RELAYING REQUIREMENTS section below.)

8. For those periods of operation during which a DG is generating capacity greater than its load demand, the DG connected to the Company's primary distribution system shall maintain a net power factor of between 0.95 lagging (consuming vars) and unity (1.00). This requirement applies to Buy/Sell Options 2, 3, & 4 unless another voltage-var schedule is approved by the Company.

9. Voltage variations due to the DG's generation shall be within the voltage standards prescribed by ANSI C84.1, Range A.

10. The phase voltages produced by the DG must be balanced. The generated waveform must be sinusoidal and free from distortion and excessive harmonics. Waveform distortion, and/or excessive harmonic content, can produce inaccurate revenue metering registration, increased losses in transformers, false relay operations, interference in telephone communications and radio/television reception, and may affect equipment (such as computers) used by customers served by the Company.

11. Under certain conditions, the Company's primary distribution system may cause unbalanced phase currents to flow in the DG's generator. It is the responsibility of the DG to protect its equipment from excessive negative sequence currents.

12. The DG may be required to limit the phase and ground fault current contribution to the Company's system by transformer impedance, transformer connection, generator connection, neutral grounding, or other means.

METERING REQUIREMENTS

In each of the Buy/Sell options, energy and capacity supplied by the Company to the DG, and/or produced by the DG, shall be determined by the appropriate meters located at a single delivery point. In Options 1 & 2, there is only one-way power flow; in Options 3 & 4, power can flow in either direction.

Where an inter tie transformer is used, the Company will install metering on the high voltage side (and/or on the low voltage side with loss compensation) to measure KWH (in), KWH (out), KW (in and out), and KVARH (in and out), where applicable. All revenue meters will be provided by the

Company. Space for Company metering equipment must be provided by the DG and must be accessible to the Company at all times. The Company reserves the right to require additional metering (and associated communications equipment) as may be required. The DG must provide space in its switch gear for the Company to install this equipment.

COMMUNICATIONS REQUIREMENTS

When the DG's installed generating capacity is 100 KW or greater, a responsible person shall be available for contact by the Company at any time the DG's generators are connected in parallel with the Company's primary distribution system. DGs connected to the primary distribution system must have a dedicated telephone line available for communications between the DG and the Company. DGs with installed capacities of less than 100 KW may satisfy this requirement with a residential or commercial telephone line.

RELAYING REQUIREMENTS

1. Because the Company is responsible for the quality and reliability of its-service, and must provide this service in a manner which is safe to the public and its personnel, the Company reserves the right to determine what protective equipment it must provide, and to refuse to operate parallel with a DG that, in the opinion of the Company's engineering staff, is not (or cannot be) operated in a manner that ensures safe and reliable interconnected operation.

2. DGs connected to the Company's primary distribution system will be required to install "utility grade" protective relays that meet all ANSI/IEEE relay standards.

3. The protection package must be designed to separate the DG from the primary distribution system during faults and during abnormal conditions of frequency, voltage, voltage phase sequence, and non-contractual reverse power flow. It should be understood that the Company must reserve the right to add or delete protective equipment, as may be applicable for a particular DG, according to its size, equipment, or potential impact on the interconnected system and/or Company customers. Refer to the table and figures at the back of this document for a typical interface installation and protection device numbers. The specific requirements are:

    a. Short circuits including ground faults. (Devices 50, 67, 59N) A circuit breaker and designated relays will be applied as necessary to provide protection for faults on either the Company's or DG's electrical system.
    b. Overload. (Device 67) AC directional over current relay will be used to provide overload protection and also back up protection for short circuits.
    c. Isolation. (Devices 27, 59, 81O, 81U) Should the Company's circuit to the DG become isolated from the Company's source of generation, the DG's generator may cause abnormal voltage and frequency excursions. To prevent damage from these excursions, under/over voltage and under/over frequency relays will be installed.

d. Phase sequence. (Device 47) The designated relay will monitor the proper sequence for the initial connection and also subsequent connections after Company maintenance to the inter tie circuit.
e. Reverse power. (Device 32) The designated relay will protect against reverse power flow on one-way DG systems.
f. Synchronism Check Function. (Device 25) The designated relay blocks out-of-phase closing and also prevents closing and energizing a dead low voltage bus by the generator.

4. The DG has the dual responsibility of protecting its own equipment while connected to the Company's electrical system, as well as preventing its equipment from causing problems to the Company's system. As a result, the DG must provide protection for all of the conditions outlined in the above section, as well as unbalanced load and loss of excitation.

OPERATING REQUIREMENTS

1. DGs, with installed capacities of one megawatt, but less than five megawatts, must report by telephone the previous day's hourly KWH readings to the Company's electric operating center.

2. For DGs with installed capacities of five megawatts or greater, the Company will install the necessary equipment to telemeter continuous capacity (KW) data, KVAR data (if the DG uses a synchronous generator), and hourly energy (KWH) data to the Company's Automatic Generation Control (AGC) system.

3. For those DGs using synchronous generation equipment, a voltage-var schedule, in addition to voltage regulator settings, will be jointly determined by the Company and the DG to ensure proper coordination of voltages and regulator action.

4. The DG will maintain an operating log for each of its generators. This log will be used to record the on/off status of the generating unit and to serve as a record of alarms and relay targets (or other indications of unusual conditions). This log must also record all maintenance on the unit, and associated equipment (switch gear, protective relays, etc.).

5. The DG shall discontinue paralleled operation when requested by the Company:

   a. To facilitate maintenance, test, or repair of Company facilities.
   b. During system emergencies (ref 807 KAR 5:054, Section 6).
   c. When the DG's operation is interfering with Company customers.
   d. When an inspection of the DG's generating equipment reveals a condition hazardous to the Company's primary distribution system, or reveals a lack of scheduled maintenance or maintenance records for equipment necessary to protect the Company's system (and its customers).

6. When-the inter tie breaker is out of service for maintenance, and service to the DG for load is maintained through a breaker bypass disconnect, the DG must provide a method by which the

Company can lock the DG's generator breaker open to ensure personnel and equipment safety during the period of maintenance.

OTHER CONSIDERATIONS

1. Since each DG's installation must be reviewed on an individual basis, it is extremely important that the DG contact the Company well in advance of the time parallel operation is desired. The DG should not order any equipment until the Company has reviewed the DG's plans and has defined what changes and/or additions will be necessary for safe and reliable interconnected operation. The time required to secure this approval depends on the size and location of the DG's equipment, as well as on other technical considerations.

2. The DG cannot commence parallel operation until written approval has been given by the Company. The Company reserves the right to inspect the DG's facility and to witness testing of any equipment or devices associated with the interconnection.

3. The DG should be aware that some of the Company provided equipment, discussed in the above paragraphs, have somewhat lengthy delivery times. The time from placing an order, to receiving the equipment, can exceed one year. (The same is true for equipment the DG may require, such as large transformers, power circuit breakers, etc.) Therefore, the time required to design, order, receive, and install this equipment should be taken into consideration by a DG that is making plans to operate parallel with the Company.

4. It may become necessary, in the future, to add or modify present technical requirements, and this could also affect existing DGs. Such changes might include additional equipment for harmonic filtering, more complex utility relaying schemes, etc. The Company will not change its requirements unless such changes are necessary to ensure safe and reliable interconnected operation.

5. The DG should be aware that the PSC regulation for small power production and cogeneration (807 KAR 5:054) requires owners of qualifying facilities "to pay for any additional interconnection costs to the extent that such costs are in excess of those that the electric utility would have incurred if the qualifying facility's output had not been purchased." This also applies to any subsequent changes, either to equipment owned by the' Company or the DG (as defined in the foregoing paragraph).

PROTECTION DEVICE NUMBERS FOR STAND BY GENERATION WITH PARELLEL TRANSFER SCHEME

DEVICE NO.	DESCRIPTION
25	SYNCHRONIZING OR SYNCHRONISM CHECK RELAY
27	UNDERVOLTAGE RELAY
32	DIRECTIONAL POWER RELAY
47	PHASE SEQUENCE VOLTAGE RELAY
50	INSTANTANEOUS OVERCURRENT RELAY
52	CIRCUIT BREAKER
59	OVERVOLTAGE RELAY
59N	OVERVOLTAGE TYPE GROUND FAULT RELAY
67	AC DIRECTIONAL OVERCURRENT RELAY
81O	OVERFREQUENCY RELAY
81U	UNDERFREQUENCY RELAY

Table 1.

Louisville Gas and Electric Company
Distributed Generation Guidelines
for
Secondary Distribution System Interconnection

INTRODUCTION

A Distributed Generator (DG) is defined as any generator connected to the LG&E Energy Corp. Electric Power System (EPS) through a Point of Common Coupling (PCC). This manual is provided to assist in designing and/or selecting equipment that can be installed and operated in a manner that will ensure safe and reliable interconnected operation as required by IEEE 1547.

There are three types of circuits which connect the Company's generating stations with its substations and customers: (1) Transmission; (2) Primary Distribution; and (3) Secondary Distribution. A DG can be connected, depending on its output voltage, size, and other characteristics, to anyone of these systems.

1. TRANSMISSION SYSTEM. This system is used, by the Company, to transmit large quantities of power to and from other utilities, and from its generation sources to its distribution substations. Some large industrial customers receive electric power directly from this system. The following voltages for interconnection are available:

    a. 69 KV, three phase, 3-wire
    b. 138 KV, three phase, 3-wire
    c. 345 KV, three phase, 3-wire

2. PRIMARY DISTRIBUTION SYSTEM. Some large commercial and small industrial customers are provided service at the available voltages in this system, which is shown below. This system is used, primarily, to transmit power to the Secondary Distribution System.

    a. 4160Y/2400 V, three phase, 4-wire
    b. 12470Y/7200 V, three phase, 4-wire
    c. 13800 V, three phase, 3-wire
    d. 34500Y/19920 V, three phase, 4-wire

3. SECONDARY DISTRIBUTION SYSTEM. This is the system to which the majority of the Company customers are connected, including most served under the Company's residential rate. The following voltages are available for interconnection:

    a. 120/240 V, single phase,-3-wire
    b. 208 Y/120 V, three phase, 4-wire
    c. 240 V, three phase, 3-wire
    d. 480 Y/277 V, three phase, 4-wire
    e. 480 V, three phase, 3-wire

To which system a DG should (or can) connect, depends on the size of the DG, and on the proximity of the various systems with respect to the DG, in addition to other technical considerations. A DG should consult with the Company, prior to purchasing its equipment, to determine which system is appropriate for interconnection.

This particular guidebook only provides technical assistance to the DG that is planning to interconnect with the secondary distribution system. Other guidebooks are available for those who would likely interconnect with the primary distribution or transmission systems.

SEPARATE SYSTEMS

A separate system is defined as one so configured that there is no possibility of connecting the customer's generating equipment in parallel with the utility's system. For this design to be practical, a customer must be capable of transferring load between its generation source and the company source in a non-parallel mode. This can be accomplished by either an electrically or mechanically interlocked switching arrangement which precludes paralleling the two sources of generation.

> **NOTE: Any closed transition switching ("make before break"), even momentary if greater than 100 ms (0 ms for a secondary grid or spot network) per IEEE 1547 and LG&E requirements, is considered to be parallel operation. Any DG system utilizing a closed transition scheme must be designed and constructed in accordance with the design requirements for parallel operation as further defined in this document.**

If a customer is planning a separate system, the Company requires verification that the transfer scheme meets the non-parallel requirements. This is accomplished by submitting drawings to the Company for approval and, if the Company so elects, by field inspection of the transfer scheme. The Company cannot be responsible for approving the customer's generation equipment and assumes no responsibility for its design or operation. The only reason the Company reserves the right to approve the drawings and/or inspect the transfer scheme is to ensure that its personnel can safely work on Company equipment, and to ensure that other customers served by the same system will not be adversely affected by the separate system.

Most Uninterruptible Power Supply (UPS) systems do not specifically meet the separate system criteria, however if they are not capable of back feed (transfer of power to the utility), they will be classified as a separate system. If they can back feed, they must meet the requirements of the IEEE-1547 as-a DG, as well as the technical requirements for parallel operation.

THE FOUR BUY/SELL OPTIONS

There are four options the DG has regarding the purchase and sale of power with the Company:

1. The DG does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements.

2. The DG sells to the Company the energy and capacity it produces, but is not a customer of the Company.

3. The DG sells to the Company the energy and capacity it produces in excess of its total load, and purchases from the Company its net load requirements.

4. The DG sells to the Company the total energy and capacity it produces, while simultaneously purchasing from the Company its total load requirements.

Once a DG has selected one of the four options, and a written covenant has been executed, the DG can not change options until the signed agreement has expired or has been terminated by mutual agreement of the parties.

TYPES OF GENERATORS

There are three general classifications of power producing equipment: synchronous generators, induction generators, and static inverters. Any of these may be used by a DG, but there are different technical areas to address for each to ensure safe and reliable interconnected operation.

1. SYNCHRONOUS GENERATORS. This is the type of generator that most utilities, including the Company, uses to produce power. A synchronous generator does not have to rely on the utility system for its excitation. Therefore, a synchronous generator is capable of keeping a utility line energized even after the line has been isolated from other generating sources. The Company reserves the right to inspect the DG's facility

2. INDUCTION GENERATORS. An induction generator must inherently have the utility source to establish a magnetic field for generation. Depending on the DG's generator size, this can create a voltage problem. The Company may require the DG to install capacitors (and capacitor switching equipment) to limit the adverse effects of reactive power flow on the Company's primary distribution system capacity and voltage regulation. It should be noted, however, that the installation of capacitors for reactive power supply at, or near, an induction generator greatly increases the risk that the- induction generator may become self-excited if accidentally isolated from the Company's electrical system. The self-excited induction generator can produce abnormally high voltages which can cause damage to the equipment of Company customers. Over voltage relays can limit the duration of such over voltages but cannot control their magnitude because of the rapid voltage rise which occurs with self-excitation. Because of this, reactive power supply for large induction generators must be studied on an individual basis. In general, self-excitation problems are most likely in areas of low load density. As with large induction machines used as motors, the inrush current resulting from the starting (or synchronizing) of an induction machine used as a generator may cause an instantaneous voltage drop that can create problems for customers of the Company. For this reason, the Company must also study, on an

individual basis, the effect the starting (or synchronizing) of the DG's induction generator will have on system voltage.

3. INVERTER SYSTEMS. Reactive power supply requirements for inverter systems are similar to those for induction generators and the general guidelines for induction generators also apply to inverters. Inverter systems may also be capable of isolated operation. Self-commutated inverters have this capability by design. Line-commutated inverters could operate isolated if connected to rotating machines which provide the necessary commutation. The design and protection of inverter systems must address these possibilities of self-excited operation.

GENERAL DESIGN CONSIDERATIONS

1. The DG's installation must meet the IEEE 1547 Standard. The DG shall also meet all applicable national, state, and local construction and safety codes.

2. The Company will purchase, install, operate, and maintain a dedicated transformer (herein referred to as "intertie transformer") that serves to step up the DG's generated voltage to that of the Company's primary distribution system.

3. The DG is responsible for providing the necessary protection for its own system, as well as protecting against adverse effects, from its operation, to the Company's system. Where applicable, the DG will provide protection for the various electrical problems outlined in the RELAYING REQUIREMENTS section below.

4. The Company will install and own required revenue metering equipment. (See the METERING REQUIREMENTS section below.)

5. A manual load break disconnecting device will be installed by the Company at the point of the interconnection. This device will be controlled by the Company to ensure Company personnel can service Company lines and equipment safely. It will be of the type allowing Company personnel to visibly see the electrical break.

6. The DG shall provide adequate facilities for proper synchronization of its generator with the Company such that synchronism can be accomplished without causing undesirable currents, surges, or voltage dips on the Company's primary distribution system. The DR shall parallel with the Utility without causing a voltage flicker at the PCC greater than 5%. Either induction starting (if the inrush will not exceed allowable limits), automatic synchronizing, or manual synchronizing supervised by a synchronizing relay must be provided. The DG must never attempt to parallel its system with the Company's primary distribution system when the DG's synchronizing facilities are malfunctioning or inoperative. Manual synchronizing without relay supervision is not permitted.

7. The DG shall provide means for automatically disconnecting its generator from the Company's primary distribution system for those occasions when the Company's primary distribution system becomes isolated from its source of generation, and for the proper resynchronization of its generator after such interruptions or isolations. Three phase automatic reclosing devices are installed on the Company's primary distribution system, thus the speed of the DG's automatic isolation equipment must be such as to disconnect its generation prior to automatic re-energization of the circuit by the Company. (This is discussed further in the RELAYING REQUIREMENTS section below.)

8. For those periods of operation during which a DG is generating capacity greater than its load demand, the DG connected to the Company's primary distribution system shall maintain a net power factor of between 0.95 lagging (consuming vars) and unity (1.00). This requirement applies to Buy/Sell Options 2, 3, & 4 unless another voltage-var schedule is approved by the Company.

9. Voltage variations due to the DG's generation shall be within the voltage standards prescribed by ANSI C84.1, Range A.

10. The phase voltages produced by the DG must be balanced. The generated waveform must be sinusoidal and free from distortion and excessive harmonics. Waveform distortion, and/or excessive harmonic content, can produce inaccurate revenue metering registration, increased losses in transformers, false relay operations, interference in telephone communications and radio/television reception, and may affect equipment (such as computers) used by customers served by the Company.

11. Under certain conditions, the Company's primary distribution system may cause unbalanced phase currents to flow in the DG's generator. It is the responsibility of the DG to protect its equipment from excessive negative sequence currents.

12. The DG may be required to limit the phase and ground fault current contribution to the Company's system by transformer impedance, transformer connection, generator connection, neutral grounding, or other means.

13. The maximum capacity for single phase interconnection is 50 KW, and capacities of this magnitude will only be permitted when they will not create problems to the Company and/or its customers

METERING REQUIREMENTS

In each of the Buy/Sell options, energy and capacity supplied by the Company to the DG, and/or produced by the DG, shall be determined by the appropriate meters located at a single delivery point. In Options 1 & 2, there is only one-way power flow; in Options 3 & 4, power can flow in either direction.

The Company will install metering on the low voltage side of the inter tie transformer to measure KWH (in), KWH (out), KW (in and out), and KVARH (in and out), where applicable. All revenue meters will be provided by the Company. Space for Company metering equipment must be provided by the DG, and must be accessible to the Company at all times. The Company reserves the right to require additional metering (and associated communications equipment) as may be required. The DG must provide space in its switch gear for the Company to install this equipment.

COMMUNICATIONS REQUIREMENTS

When the DG's installed generating capacity is 100 KW or greater, a responsible person shall be available for contact by the Company at any time the DG's generators are connected in parallel with the Company's primary distribution system. DGs connected to the primary distribution system must have a dedicated telephone line available for communications between the DG and the Company. DGs with installed capacities of less than 100 KW may satisfy this requirement with a residential or commercial telephone line.

RELAYING REQUIREMENTS

1. Because the Company is responsible for the quality and reliability of its-service, and must provide this service in a manner which is safe to the public and its personnel, the Company reserves the right to determine what protective equipment it must provide, and to refuse to operate parallel with a DG that, in the opinion of the Company's engineering staff, is not (or cannot be) operated in a manner that ensures safe and reliable interconnected operation.

2. DGs connected to the Company's primary distribution system will be required to install "utility grade" protective relays that meet all ANSI/IEEE relay standards.

3. The protection package must be designed to separate the DG from the primary distribution system during faults and during abnormal conditions of frequency, voltage, voltage phase sequence, and non-contractual reverse power flow. It should be understood that the Company must reserve the right to add or delete protective equipment, as may be applicable for a particular DG, according to its size, equipment, or potential impact on the interconnected system and/or Company customers. Refer to the table and figures at the back of this document for a typical interface installation and for protection device numbers. The specific requirements are:

    a. Short circuits including ground faults. (Devices 50, 67, 59N) A circuit breaker and designated relays will be applied as necessary to provide protection for faults on either the Company's or DG's electrical system.
    b. Overload. (Device 67) AC directional over current relay will be used to provide overload protection and also back up protection for short circuits.

c. Isolation. (Devices 27, 59, 810, 81U) Should the Company's circuit to the DG become isolated from the Company's source of generation, the DG's generator may cause abnormal voltage and frequency excursions. To prevent damage from these excursions, under/over voltage and under/over frequency relays will be installed.
d. Phase sequence. (Device 47) The designated relay will monitor the proper sequence for the initial connection and also subsequent connections after Company maintenance to the inter tie circuit.
e. Reverse power. (Device 32) The designated relay will protect against reverse power flow on one-way DG systems.
f. Synchronism Check Function. (Device 25) The designated relay blocks out-of-phase closing and also prevents closing and energizing a dead low voltage bus by the generator.

4. The DG has the dual responsibility of protecting its own equipment while connected to the Company's electrical system, as well as preventing its equipment from causing problems to the Company's system. As a result, the DG must provide protection for all of the conditions outlined in the above section, as well as unbalanced load and loss of excitation.

OPERATING REQUIREMENTS

1. For those DG's using synchronous generation equipment, a voltage-var schedule, in addition to voltage regulator settings, will be jointly determined by the Company and the DG to ensure proper coordination of voltages and regulator action.

2. The DG will maintain an operating log for each of its generators. This log will be used to record the on/off status of the generating unit and to serve as a record of alarms and relay targets (or other indications of unusual conditions). This log must also record all maintenance on the unit, and associated equipment (switch gear, protective relays, etc.).
.

3. The DG shall discontinue paralleled operation when requested by the Company:

   a. To facilitate maintenance, test, or repair of Company facilities.
   b. During system emergencies (ref 807 KAR 5:054, Section 6).
   c. When the DG's operation is interfering with Company customers.
   d. When an inspection of the DG's generating equipment reveals a condition hazardous to the Company's primary distribution system, or reveals a lack of scheduled maintenance or maintenance records for equipment necessary to protect the Company's system (and its customers).

4. When the inter tie breaker is out of service for maintenance, and service to the DG for load is maintained through a breaker bypass disconnect, the DG must provide a method by which the Company can lock the DG's generator breaker open to ensure personnel and equipment safety during the period of maintenance.

OTHER CONSIDERATIONS

1. Since each DG's installation must be reviewed on an individual basis, it is extremely important that the DG contact the Company well in advance of the time parallel operation is desired. The DG should not order any equipment until the Company has reviewed the DG's plans and has defined what changes and/or additions will be necessary for safe and reliable interconnected operation. The time required to secure this approval depends on the size and location of the DG's equipment, as well as on other technical considerations.

2. The DG cannot commence parallel operation until written approval has been given by the Company. The Company reserves the right to inspect the DG's facility and to witness testing of any equipment or devices associated with the interconnection.

3. The DG should be aware that some of the Company provided equipment, discussed in the above paragraphs, have somewhat lengthy delivery times. The time from placing an order, to receiving the equipment, can exceed one year. (The same is true for equipment the DG may require, such as large transformers, power circuit breakers, etc.) Therefore, the time required to design, order, receive, and install this equipment should be taken into consideration by a DG that is making plans to operate parallel with the Company.

4. It may become necessary, in the future, to add or modify present technical requirements, and this could also affect existing DGs. Such changes might include additional equipment for harmonic filtering, more complex utility relaying schemes, etc. The Company will not change its requirements unless such changes are necessary to ensure safe and reliable interconnected operation.

5. The DG should be aware that the PSC regulation for small power production and cogeneration (807 KAR 5:054) requires owners of qualifying facilities "to pay for any additional interconnection costs to the extent that such costs are in excess of those that the electric utility would have incurred if the qualifying facility's output had not been purchased." This also applies to any subsequent changes, either to equipment owned by the' Company or the DG (as defined in the foregoing paragraph).

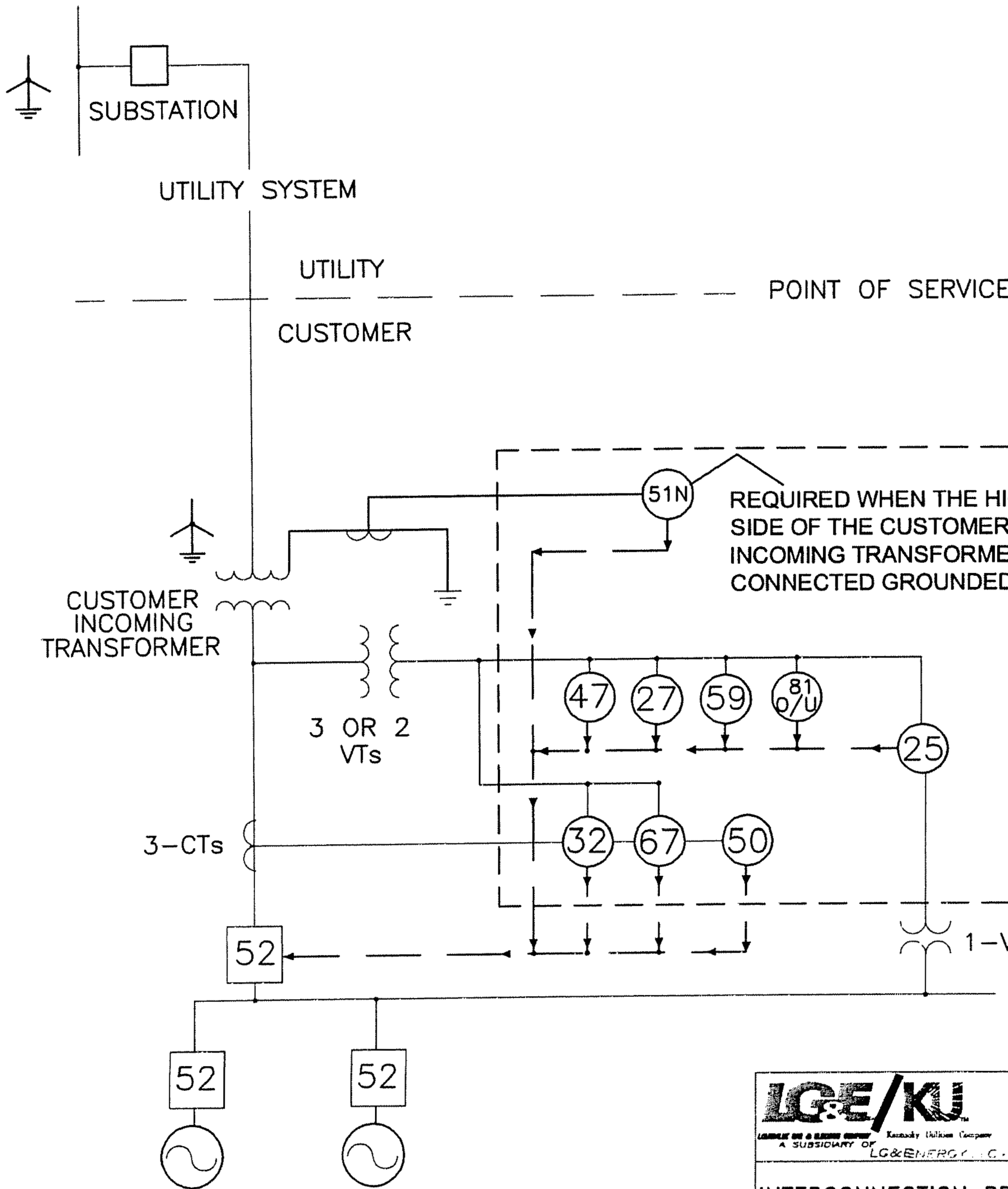
PROTECTION DEVICE NUMBERS FOR STAND BY GENERATION WITH PARELLEL TRANSFER SCHEME

DEVICE NO.	DESCRIPTION
25	SYNCHRONIZING OR SYNCHRONISM CHECK RELAY
27	UNDERVOLTAGE RELAY
32	DIRECTIONAL POWER RELAY
47	PHASE SEQUENCE VOLTAGE RELAY
50	INSTANTANEOUS OVERCURRENT RELAY
51N	NUETRAL TIME OVERCURRENT RELAY
52	CIRCUIT BREAKER
59	OVERVOLTAGE RELAY
59N	OVERVOLTAGE TYPE GROUND FAULT RELAY
67	AC DIRECTIONAL OVERCURRENT RELAY
810	OVERFREQUENCY RELAY
81U	UNDERFREQUENCY RELAY

Table 1.

LG&E INTERCONNECTION REQUIREMENTS FOR PARALLEL STANDBY GENERATION SCHEMES

TYPE I - LINE SIDE OF CUSTOMER TRANSFORMER CONNECTED GROUNDED WYE ONLY



SUBSTATION ENGINEERING AND DESIGN

A SUBSIDIARY OF LG&E ENERGY

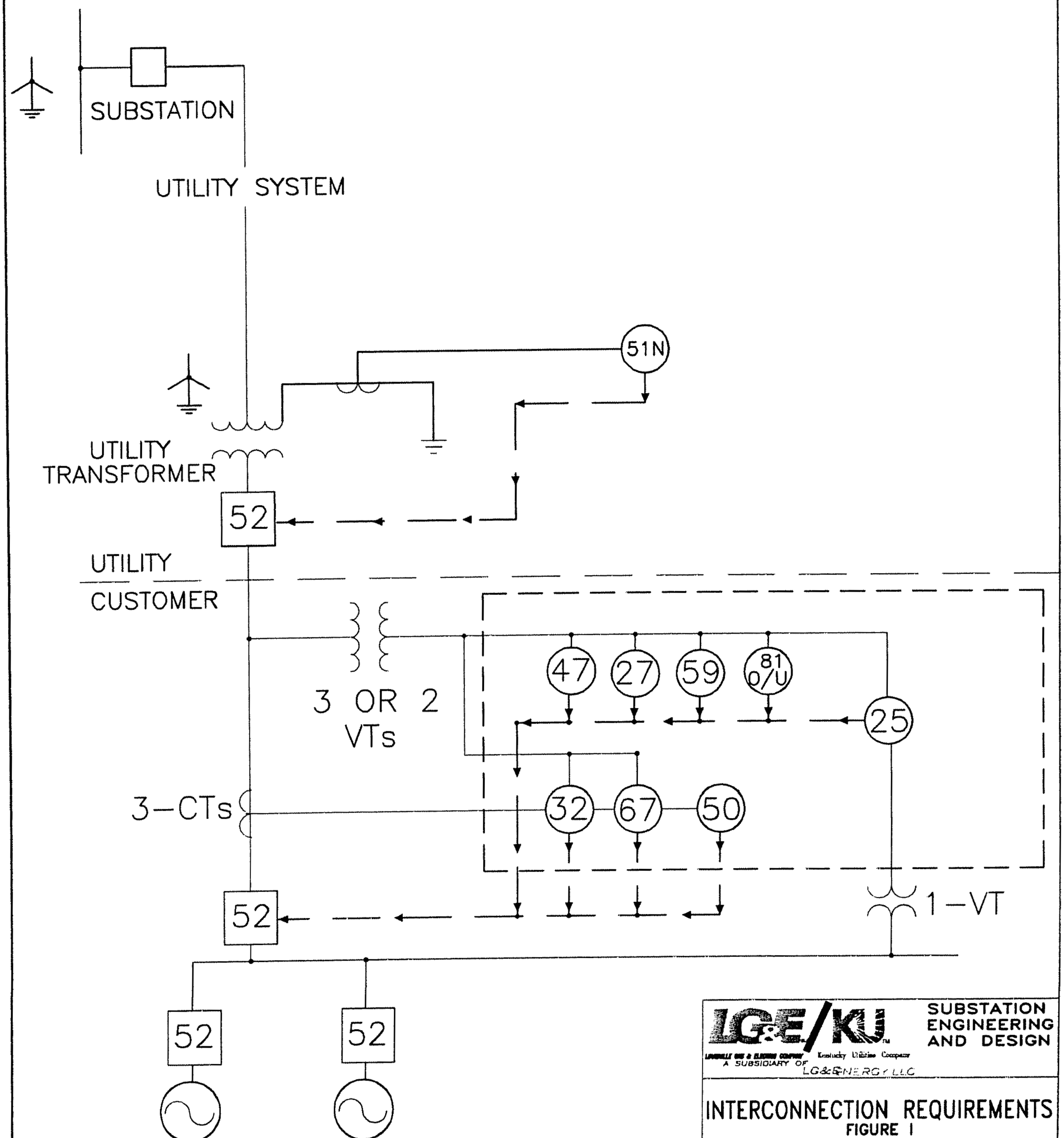
INTERCONNECTION REQUIREMENTS
FIGURE II

DRAWN: 10/6/04 Rocky Flood
REVISED: 11/11/04 Joe Clark

SPEC-251 B

LG&E INTERCONNECTION REQUIREMENTS FOR PARALLEL STANDBY GENERATION SCHEMES

TYPE I - SECONDARY INTERCONNECT TO 4.16 KV, 12.47 KV OR 34.5 KV SYSTEM



SUBSTATION ENGINEERING AND DESIGN

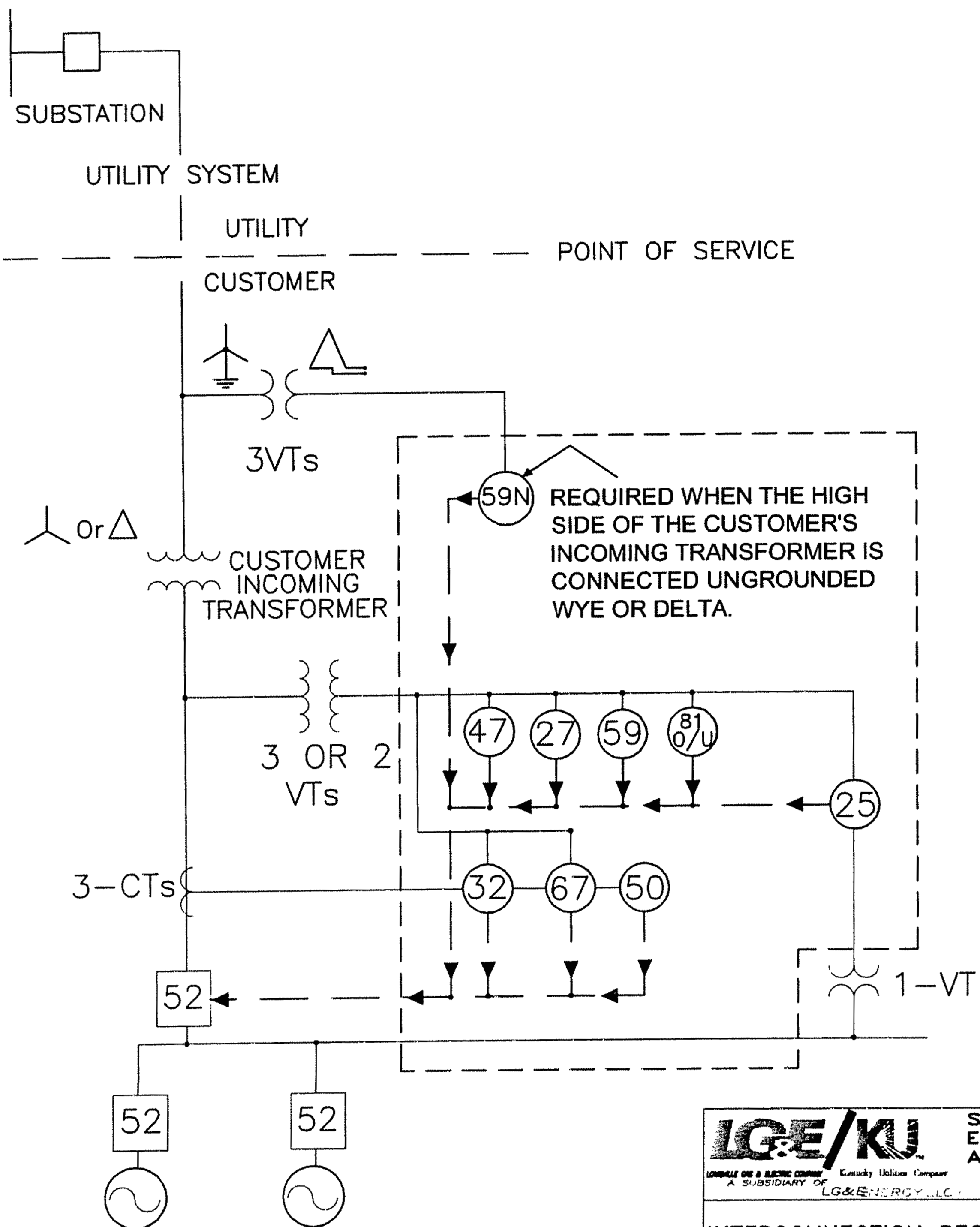
LOUISVILLE GAS & ELECTRIC COMPANY Kentucky Utilities Company A SUBSIDIARY OF LG&ENERGY LLC

INTERCONNECTION REQUIREMENTS
FIGURE I

DRAWN: 10/6/04 Rocky Flood	SPEC–251C
REVISED: 11/11/04 Joe Clark	

LG&E INTERCONNECTION REQUIREMENTS FOR PARALLEL STANDBY GENERATION SCHEMES

TYPE II - LINE SIDE OF CUSTOMER TRANSFORMER CONNECTED UNGROUNDED WYE OR DELTA



SUBSTATION ENGINEERING AND DESIGN

A SUBSIDIARY OF LG&ENERGY LLC

INTERCONNECTION REQUIREMENTS
FIGURE II

DRAWN: 10/6/04 Rocky Flood	SPEC-252 B
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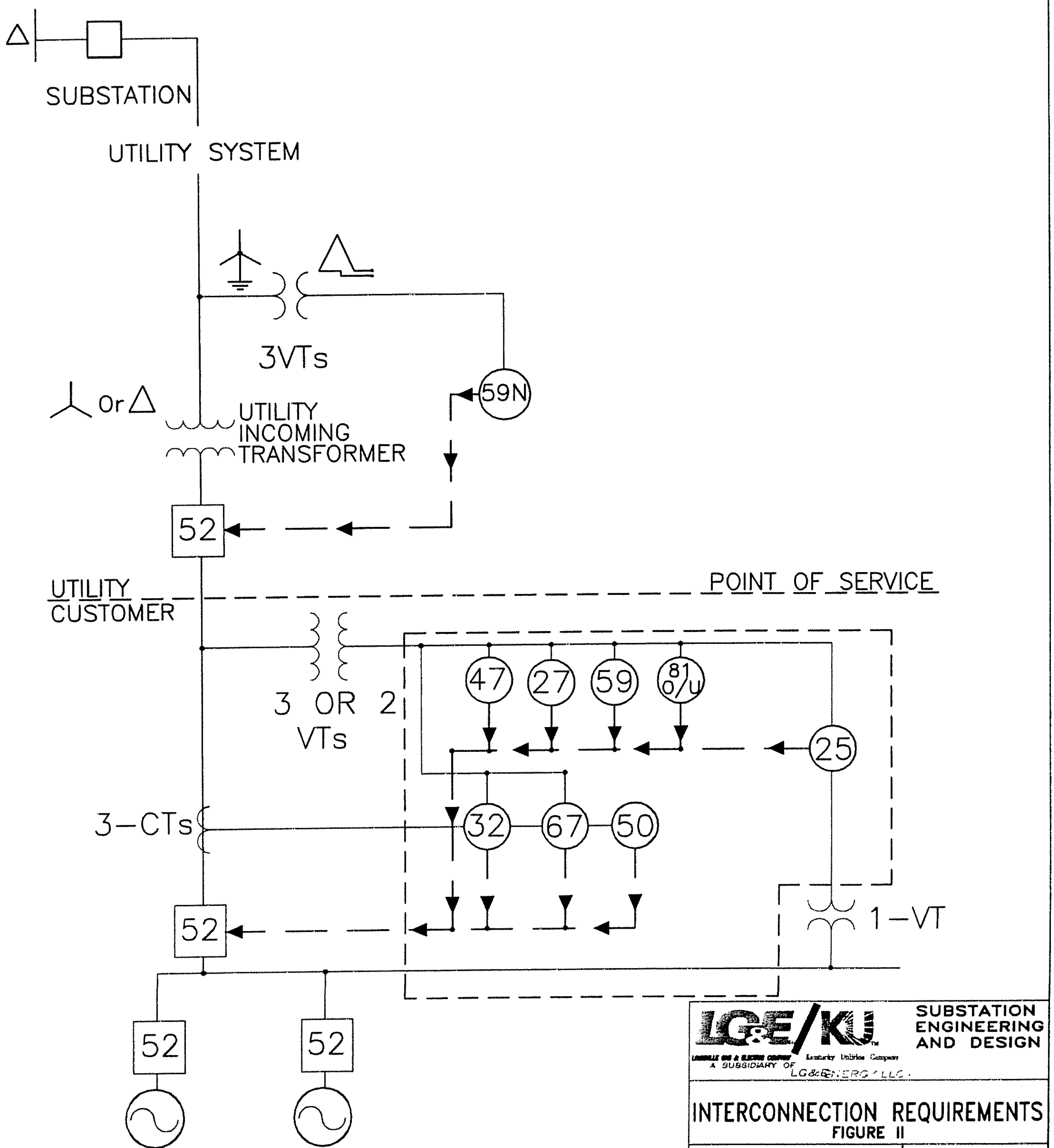
LG&E INTERCONNECTION REQUIREMENTS FOR PARALLEL STANDBY GENERATION SCHEMES

TYPE II - SECONDARY INTERCONNECTION TO 13.8 KV SYSTEM



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SUBSTATION ENGINEERING AND DESIGN

INTERCONNECTION REQUIREMENTS
FIGURE II

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