Technical and Functional Requirements for Interconnecting Distributed Generation with the EKPC Electrical Distribution System

East Kentucky Power Cooperative

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REVISION HISTORY

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EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

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Senior Engineer Date

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Senior Vice President – Power Supply Date

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COMPANY OVERVIEW

East Kentucky Power Cooperative (EKPC) is a not-for-profit, generation and transmission (G&T) electric utility cooperative that is owned by sixteen (16) distribution electric utility cooperatives, collectively known as the Member Systems. EKPC's purpose is to generate and deliver wholesale electricity to the Member Systems who distribute power to retail customers (members). The Member Systems own and maintain their own distribution and metering systems; EKPC owns and maintains all distribution substations.

INTRODUCTION

This document specifies the minimum requirements for the safe and effective operation of Distributed Generation (DG) up to 10 MVA interconnecting with either an existing Member System's radially operated electrical distribution feeder (up to 25kV) or directly to an EKPC distribution substation via an express feeder. DG systems may not be interconnected to loop feed distribution systems, spot networks, or grid networks.

All DG interconnections that do NOT qualify for net metering in Kentucky must be approved by both EKPC and the Member System to which the DG will be interconnected.

For simplicity, this document will use the term "DG" to refer to any distributed generator, co-generator, or small power producer facility that does NOT qualify for net metering. The term "utility" will be used to refer to either EKPC or the Member System (as appropriate) to which interconnection is being sought.

DG owners/operators and utility personnel shall use this document when planning the installation of interconnected DG systems. Although this document establishes criteria and requirements for interconnection, this manual is not a design handbook.

This document provides the minimum functional technical requirements that are universally needed to help assure a safe and technically sound interconnection. As such, the requirements contained within this document may not cover all details for specific DG installations. Therefore, the DG is encouraged to discuss project plans with the Member System and EKPC before designing, constructing, and purchasing equipment for the DG facility.

The interconnection requirements set forth in this document for the parallel operation of DG with the utility's distribution system are provided for substation and distribution interconnections of synchronous generators, induction generators, D.C. generators with inverters, and other inverter based generating technologies.

At the utility's discretion, all requirements in this document may be superseded by requirements given in the following standards:

ANSI Std. 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems;"

ANSI C84.1-1995, "Electric Power Systems and Equipment – Voltage Ratings (60Hz);"

IEEE Std 519-1992, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems;"

IEEE Std. 929-2000, "Recommended Practice for Utility Interface of Photovoltaic (PV) Systems;"

IEEE Std. 485-1983, "Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations."

LIMITATIONS

As their wholesale and service provider, this interconnection document has been developed by EKPC on behalf of the Member Systems. All applicants must check with the Member System from which permission to interconnect is being sought to determine if additional requirements exist.

This document is not intended for net metering installations. Net metering rules and regulations are included in each Member System's net metering tariff.

DG installations with capacity greater than 10 MVA will need to contact EKPC for interconnection rules and regulations.

This document is not intended for DG installations seeking to interconnect with the EKPC transmission system at voltages 69 kV and above. For these installations, all applicants must contact EKPC for the appropriate documents.

The minimum required protective relaying and safety devices and requirements specified in this document are necessary to ensure the safety of utility workers and the public. In addition, these requirements are intended to protect utility facilities and other customer equipment from damage and disruptions caused by faults, malfunctions, and improper operation of the DG facility. The minimum protective relaying and interconnection requirements given in this document do not necessarily include additional protective and safety devices as may be required by industry and/or government codes and standards, equipment manufacturer requirements, and prudent engineering design and practice to fully protect the DG facility or facilities; compliance with these regulations are the sole responsibility of the DG.

The information in this document contains general information about the interconnection requirements for customer owned DG facilities. All applicable regulatory, technical, safety, and electrical requirements and codes are not contained in their entirety in this document. DG facilities are also subject to contractual and other legal requirements, which are only summarized in this document. Those regulations, requirements, contracts, and other materials contain complete information concerning DG interconnection and take precedence over the general provisions in this document.

This document, as well as the various other agreements and rate schedules, are subject to revision. Therefore, the DG is encouraged to check with the Member System and EKPC for the latest revision prior to commencing a DG project requiring interconnection and parallel operation with the utility distribution system.

DG GENERATING REQUIREMENTS

The utility will permit any applicant to operate DG in parallel with the utility's electrical distribution system whenever such operation can take place without adversely affecting other customers, the general public, utility equipment, and utility personnel. To minimize this interference caused by the interconnection of DG, the DG shall meet the criteria given in this attachment.

The DG operating requirements outlined in this attachment shall be met at the point of common coupling (PCC). The PCC is defined as that electrical point where the distribution system owned and operated by the utility interconnects to the DG facility's distribution system. Often, but not always, the PCC is the metering point. The PCC is not to be confused with the DG point of interconnection. The DG point of interconnection is that electrical point where the output terminals of a DG system interconnect to an electrical distribution system, which may or may not be the same point as the PCC.

The DG operating requirements outlined in this attachment apply to the interconnection of either a single DG unit or the aggregate of multiple DG units within a single DG facility.

The DG operating requirements outlined in this attachment are functional and apply to all generating technologies: Synchronous generators, induction generators, D.C. generators with inverters, and other inverter based generating technologies.

VOLTAGE[1]

The DG shall not actively regulate the voltage at the PCC.

In general, the Member System maintains a voltage schedule consistent with ANSI Std. C84.1-1995 Range A. With that, a DG shall produce voltages within 5% of the nominal voltage of the distribution system to which the DG is interconnected.

Under certain emergency situations, the Member System distribution system may operate within ± 10% of nominal voltage. The DG is required to provide voltage sensing equipment and an automatic means of disconnecting to protect their equipment during abnormal voltage operation.

The DG must disconnect its generating equipment if the DG cannot maintain a voltage within 10% of the nominal voltage of the Member System's distribution system.

FREQUENCY

The nominal operating frequency of the utility's distribution system is 60 Hz. The DG shall be designed for this frequency and will not contribute to any variation from the prevailing frequency when the DG is in operation.

[1] 807 KAR 5:041. Electric. Section 6. Voltage and Frequency.

POWER FACTOR

DG systems using synchronous generators shall absorb or produce reactive energy (VArs) such that the overall power factor is between 0.90 lagging and unity or between unity and 0.9 leading, respectively. The utility may request that the DG adjust the power factor within the above stated limits.

DG systems using induction generators with nameplate power factor below unity, shall install reactive energy capacity (capacitors) such that the DG will operate within 1% (leading or lagging) of unity power factor.

POWER QUALITY

The interconnection of DG to the utility distribution system shall not degrade the power quality for existing utility customers. The utility may install power quality monitoring equipment to verify compliance of the DG with the power quality requirements outlined in this document. Should the DG be found to be out of compliance, the DG will be responsible for reimbursing the utility for the cost of the power quality monitoring equipment, telecommunication equipment and services, and studies of the power quality data analysis.

FLICKER

Though defining the particular amount and frequency of voltage flicker that constitutes a problem is highly subjective, this requirement is necessary to minimize the adverse voltage effects to other customers on the utility system.

Any voltage flicker resulting from the interconnection of the DG to the utility distribution system shall not exceed the "Border Line of Irritation" curve given in Figure 10-3 – Maximum Permissible Voltage Fluctuations of IEEE Std 519-1992.

SYNCHRONIZATION

When energizing the DG in parallel with the utility's distribution system, the DG shall:

i. Not cause a voltage fluctuation greater than ±5% of the prevailing voltage on the utility's distribution system;

ii. Not cause a dip in voltage on the utility's distribution system due to inrush currents in excess of two volts on a 120 volt base;

iii. Meet the flicker requirements outlined in this document.

HARMONICS

In general, the utility restricts the injection of voltage and current harmonics to limits defined in the IEEE Std. 519-1992. With that, the total harmonic distortion (THD) of voltage or current created by a DG must not exceed 5% of the fundamental, 60 Hz voltage or current waveform.

$$\% \, THD = \frac{\sqrt{\sum_{i=2}^{\infty} h_i^2}}{h_1} \, x \, 100$$

Where:

h_i = the magnitude of the i^{th} harmonic of either voltage or current;
h_1 = the magnitude of the fundamental voltage or current.

Any single harmonic shall not exceed 3% of the fundamental frequency.

$$\%\ Single\ Harmonic\ Component\ Distortion = \frac{h_i}{h_1}\ x\ 100$$

Where:

h_i = the magnitude of the i^{th} harmonic of either voltage or current;
h_1 = the magnitude of the fundamental voltage or current.

SYSTEM PROTECTION

Abnormal conditions can arise on the utility's distribution system that require a response from interconnected DG to ensure safety of utility personnel and the general public. Additionally, the DG shall provide adequate protection to ensure safety to DG personnel and avoid damage to DG facilities.

The DG shall provide adequate protection to avoid damage to utility facilities and other utility customers' facilities during abnormal DG operation or DG fault conditions.

TRANSFER TRIP

If at any time it is determined that the DG cannot provide adequate protection to the utility distribution system for any abnormal condition discussed in this attachment, the DG shall furnish and install a transfer trip receiver(s) at its facility to receive a tripping signal(s) originating from a utility location(s). This additional protection would also necessitate the DG to reimburse the utility for the purchase and installation of transfer trip equipment at the utility location(s) and a communications channel and associated equipment between the utility location(s) and the DG facility.

Should the utility deem that a transfer trip system is required, the utility will specify all equipment and the choice of telecommunication including protocol necessary for the transfer trip scheme. The DG shall purchase and install a utility approved Remote Terminal Unit (RTU) and a utility grade relay with targets. This relay will be used to trip the DG interconnection breaker(s) and provide an alarm(s) to the RTU.

In some instances, it may be advantageous to simultaneously trip both the DG interconnection breaker(s) and the DG generator breaker(s). The DG is encouraged to discuss this additional functionality of the transfer trip scheme with the utility.

With utility approval, a generator breaker contact may be used to disable transfer trip of the interconnection breaker when the generator breaker is open.

The DG shall not be allowed to operate in parallel with the utility if either the RTU or the associated telecommunication system necessary for the transfer trip scheme is out of service or otherwise unavailable.

INADVERTENT ENERGIZATION

The DG shall not interconnect and operate in parallel with the utility distribution system when the utility distribution system is de-energized.

The DG interconnection breaker shall be automatically locked out and prevented from closing into a de-energized or partially de-energized (loss of any one phase) utility distribution system. The interconnection breaker close circuit shall include a synch check and an over/under voltage permissive contact to prevent closing the breaker when unfavorable voltage conditions exist.

Faults on the Utility

The DG shall detect and automatically disconnect from the utility distribution system for faults on the utility distribution system to which it is connected.

See the Reclosing Coordination and Reconnection requirements given in this attachment.

Unintentional Islanding

An island is the condition in which a portion of the utility's distribution system is energized solely by the DG, while that portion of the distribution system is electrically separated from the rest of the utility's distribution system.

At no time shall the DG be allowed to form an island in which a portion of the utility's distribution system is energized solely by the DG. The DG shall detect and disconnect from the utility's distribution system within two seconds of the formation of an island.

Reclosing Coordination

The EKPC transmission lines have automatic instantaneous and time delay reclosing. Likewise, the Member System distribution feeders have automatic instantaneous and time delay reclosing.

The DG is responsible for protecting its equipment and facility from being reconnected out-of-synchronism with the utility distribution system after automatic reclosing of a utility transmission line or distribution feeder breaker. The DG shall provide high speed protective relaying to remove its equipment from the utility's distribution system prior to automatic reclosures.

To avoid the DG from providing fault current, the DG shall disconnect from the utility distribution system to which it is connected prior to reclosure by utility breakers.

The DG will receive reclosing timing schemes for the distribution feeder and transmission line relays, as applicable, from the utility. As a general rule, those utility breakers set for instantaneous reclosing will have a re-strike time in the range of 6 to 8 cycles (0.1 to 0.133 seconds).

Voltage

The DG shall disconnect from the utility distribution system when the prevailing voltage on utility distribution system is less than 88% or greater than 110% of the nominal voltage of the utility's distribution system.

Frequency

The DG shall disconnect from the utility distribution system when the prevailing frequency on utility distribution system is less than 59.8 Hz or greater than 60.5 Hz.

Reconnection

Following an abnormal condition on the utility's distribution system, the DG shall contact the utility to ascertain if and/or when the utility distribution system has stabilized and if its configuration can accommodate reconnection of the DG. The DG must obtain permission from the utility prior to reconnecting in parallel with the utility distribution system.[2]

DG INTERCONNECTION BREAKER RELAY

The following are the minimum relay requirements for the interconnection and generator (as appropriate) breakers:

A. All DG interconnection and generator (as appropriate) breaker relays shall be utility grade;

B. Phase over-current relays (one per phase) with instantaneous and voltage restraint time delay. One ground over-current relay with instantaneous and time delay elements. Each element of the phase and ground relays shall have its own target;

C. Over/under voltage relays, which monitors (is installed) on the utility side of the interconnection breaker;

D. Over/under frequency relays, which monitors (is installed) on the utility side of the interconnection breaker;

E. Directional power (reverse power flow) relays may be required to limit power flow to contractual agreements;

F. All solid state relays requiring an auxiliary power source shall be powered from a DG station battery; ac to DC converters are unacceptable. The station battery shall be sized for an eight hour duty cycle in accordance with IEEE Std. 485-1983. At the end of the duty cycle, the battery shall be capable of tripping and closing all DG interconnection and generator (as appropriate) breakers;

G. All DG interconnection relaying shall have dedicated current transformers (CTs). All relaying CTs shall have a minimum accuracy of C200. Saturation current shall not be more than 10% of the available fault current at the PCC.

ISOLATION DEVICE

The DG shall install and maintain a lockable, visible-break isolation device (disconnect switch) or motor-operated disconnecting device at the PCC (or at the generator terminals, as appropriate, for co-generation installations). The disconnecting device shall be appropriately labeled and accessible to utility personnel at all times.

[2] See agreed upon operating procedures.

MAINTENANCE AND OPERATING REQUIREMENTS

After the DG is in service, the utility reserves the right to test or review, on request, the calibration and operation of all protective equipment including relays, circuit breakers, batteries, etc. at the interconnection, as well as review DG maintenance records. A review of the calibration and operation of protective equipment may include utility-witnessed trip testing of the interconnection and generator (as appropriate) breakers by its associated protective relays.

The failure of the DG to maintain its interconnection equipment in a manner acceptable to the utility or to furnish maintenance records on demand may result in the DG being prevented from operating in parallel with the utility.

OWNERSHIP

The protective equipment (relays, breakers, etc.) located at the PCC required to disconnect the DG from the utility shall be owned, operated, and maintained by the DG.

INTERCONNECTION BREAKER RELAY SETTING CALCULATIONS

All calculations for the DG's interconnection breaker relay shall be submitted for review and acceptance by the utility to assure protection of utility equipment and reliability of service to the adjacent utility customers.

The DG shall be required to change relay settings, if necessary, to accommodate changes in the utility system.

CALIBRATION AND FUNCTIONAL TRIP TESTS

The DG shall be responsible to have calibration and functional trip tests performed on its fault and isolation protection equipment including the DG station batteries. These tests shall be performed prior to placing equipment in service. Thereafter, station batteries will be tested annually, while relays will be tested once every three years.

Copies of these test results shall be submitted to the utility no later than five working days after completion of the tests.

All testing and calibration shall be performed by a qualified, independent, testing organization acceptable to the utility in accordance with industry standards and shall be submitted to the utility for review and acceptance. Battery tests shall meet the requirements of IEEE Std. 450-1987. The utility reserves the right to witness and accept or reject the results of all tests. The utility shall be notified of testing five business days in advance.

POWER QUALITY

If harmonic distortion or flicker problems affecting other customers' equipment can be traced to the parallel operation of the DG with the utility, the DG shall not be allowed to operate in parallel with the utility until the problem is corrected.

DG SITE WORK

If the utility is requested to work at the DG site, the utility operating and maintenance personnel shall inspect the site to ensure that all utility safety requirements have been met. If not, commencement of the requested work shall be delayed until conditions are deemed safe by the utility.

REAL-TIME MONITORING

For those DG systems with rated (nameplate) capacity of 1 MW or greater (single unit or aggregate behind a single PCC), a Supervisory Control and Data Acquisition (SCADA) system is required. As part of the SCADA system, the DG shall purchase and install a utility approved Remote Terminal Unit (RTU) that shall provide key operating parameters of the DG to EKPC's Energy Management System (EMS) in real-time. The key DG operating parameters include but are not limited to:

A. Status
   i. Interconnection breaker and generator breakers;
   ii. Generator or inverter run and availability;

B. Alarms
   i. Loss of DC to interconnection and generator breakers;
   ii. Loss of DC to RTU and loss of ac to RTU battery charger;

C. Analog Telemetry
   i. Real time voltage, current, real power (watts), reactive power (VArs), and power factor at each breaker at the PCC;
   ii. Metering Data: Dual direction, pulse accumulation of MWHr and MVArHr;

D. Transfer Trip (if equipped)
   i. Output trip signal;
   ii. Input trip/alarm signal from interconnection breaker target relay;
   iii. Loss of transfer trip alarm.

When real-time monitoring of the DG is required, the utility will specify all equipment and the choice of telecommunication including protocol necessary for the scheme.

The DG shall not be allowed to operate in parallel with the utility if either the RTU or the associated telecommunication system necessary for the transfer trip scheme is out of service or otherwise unavailable.

With utility permission, the DG shall be allowed to operate in parallel with the utility if either the RTU or the associated telecommunication system necessary for providing all but the transfer trip scheme to the utility is out of service or otherwise unavailable.

All costs for additional hardware and software for integration on the utility's EMS necessary for the DG interconnection shall be the responsibility of the DG.

Should the Member System have a SCADA system in place and wish to receive any or all of these same DG operating parameters:

i. The Member System reserves the right to require DG operating parameters be made available for DG installations of less than 1 MW;

ii. The Member System will make every effort to reduce or eliminate redundant equipment and telecommunications burden of the DG by leveraging existing telecommunications in-place between EKPC and the Member System.

DIRECT SUBSTATION INTERCONNECTIONS

All costs associated with upgrading the utility's distribution substation to accommodate an interconnection of the DG by means of a dedicated (express) feeder are the responsibility of the DG. These costs include, but are not limited to:

A. Engineering design;

B. Labor for construction, inspection, and testing;

C. Equipment:
   i. Breaker and associated protection equipment;
   ii. Grade work;
   iii. Additional fencing;
   iv. Ground grid extension;
   v. Bus extension and associated support structures
   vi. Foundation work.

Details of the cost of construction, operation, long term maintenance, and ownership issues of the distribution feeder shall be negotiated between the DG and the utility.

METERING

Depending upon the contractual agreement between the DG and the utility, metering may be required by EKPC, the Member System, or both. The DG shall contact EKPC and/or the Member System, as appropriate to the installation, to obtain metering requirements.

ENGINEERING STUDIES

Final acceptance of the interconnection by the utility will be contingent upon the utility's acceptance of all of the DG systems interconnection equipment.

The utility will perform engineering studies to determine the exact electrical configuration of the interconnection and DG systems and to identify any required additions, modifications, upgrades, or changes to the utility system. Major equipment requirements such as circuit breakers and special protective relaying shall also be studied.

Items and issues requiring investigation include:

A. Equipment short circuit duty;

B. DG breaker relay protection coordination with:
   i. Transmission relay breakers;
   ii. Distribution substation relay breakers;
   iii. Distribution feeder breakers;
   iv. Down-line distribution feeder breakers;
   v. Distribution branch circuit fuses;

C. Breaker failure requirements;

D. Dead-line Operating Constraint mechanisms and schemes;

E. Voltage profile and reactive energy (VAr) requirements;

F. Evaluation of distribution system capacity constraints.

PRELIMINARY REVIEW

To help avoid unnecessary costs and delays, a substation one-line diagram should be submitted to the utility for acceptance prior to ordering equipment or commencing construction. Installing the DG without prior written acceptance of the equipment by the utility is done at the DG's own risk. The DG shall be solely responsible for all costs associated with the replacement of any equipment that has not been accepted by the utility.

If the DG makes changes in the design of the project, any previous information furnished by the utility shall be subject to review and possible changes.

The DG shall meet all applicable local, county, municipal, and state (electrical, zoning, building, etc.) codes.

IMPACT STUDY

The Impact Study requires the DG to complete Attachment 7: Small Generator Interconnection Request Application Form

In addition, the DG must submit two copies of the following to EKPC and two copies to the Member System:

A. Substation one-line diagram;

B. Relay functional diagram showing:
   i. Current transformer (CT) circuits and turns ratio;
   ii. Potential transformer (PT) circuits and turns ratio;
   iii. Relay connections;
   iv. Protective control circuits;

   Note: All interconnections with utility circuits should be clearly labeled.

C. Three-line:
   i. ac schematic diagrams of transformers;
   ii. ac schematic diagrams of the bus protection relay;
   iii. Transformer connections;
   iv. Grounding connections;

D. Interconnection breaker data:
   i. ac and DC schematic diagrams;
   ii. Speed curve;

E. Protective relay equipment list:
   i. Manufacturer make and model number;
   ii. Relay ranges;
   iii. Manufacturer bulletins;
   iv. Relay curves and proposed settings;

F. Generator nameplate data:
   i. Transient impedance;
   ii. Sub-transient impedance;
   iii. Synchronous impedance;

G. Transformer
   i. Nameplate data;
   ii. Positive sequence impedance;
   iii. Negative sequence impedance;

H. Generator protection scheme.

I. Equipment specifications

J. Telecommunication Protocol

COMMISSIONING TEST

The DG will not be allowed to interconnect and operate in parallel with the utility's distribution system until appropriate commission tests, specified in this document, have been performed.

After construction is complete, functional tests of all protective equipment shall be performed by a qualified testing company acceptable to the utility. The utility reserves the right to witness such tests. For these tests, the utility must be given at least five business days written notice (or as otherwise mutually agreed) of the test schedule.

If the protective relay settings have been correctly applied and the functional tests are successful, the utility will permit the DG to interconnected and operate in parallel with the utility distribution system.