Back to Table of Contents

Intertie Requirements for DGs Connected to Radial Distribution Feeders

Gerard L. Gustafson, Basler Electric Company

Presented before the
31st Annual
Western Protective Relay Conference
Spokane, Washington
October 19-21, 2004

This page intentionally blank.

Prepared by Basler Electric for presentation to the
Western Protective Relay Conference, October 2004.
Rev. date 09/14/04

Intertie Requirements for DGs Connected to Radial Distribution Feeders

Gerard L. Gustafson, Basler Electric

Abstract

Standards for interconnecting Distributed Generators (DGs) to the utility system have been developed that address DGs of various sizes to systems of varying complexity. IEEE Standard 1547-2003 for Interconnecting Distributed Resources with Electric Power Systems is one such standard. This paper will review some of these protection requirements for DGs connected to radial distribution feeders.

Introduction

Basic intertie protection for DGs connected to radial distribution feeders includes preventing islanding of the DG by detecting abnormal voltages and frequencies at the Point of Common Coupling (PCC).

As the size of the DG increases in relation to the distribution feeder source and load, the protection required includes fault detection for faults on the distribution feeder. This leads to complications of possible current reversal in the utility substation breaker and the possible need for directional protection.

The connection-type of the interconnecting transformer can further complicate the protection requirements by requiring ground overvoltage protection for transformers with and ungrounded primary or additional overcurrent protection on systems with a grounded transformer primary.

Where DG power is exported onto the utility system, transfer trip relaying may be required to ensure tripping of the DG prior to the utility breaker reclosing.

These topics will be discussed and expanded throughout this paper.

Principles for Interconnection of DGs

Distributed generation is a viable method of allowing utilities to defer the building of larger fossil fuel or nuclear power plants. Intertie requirements need to be ascertained for each new DG added to the distribution system.

The purposes of establishing intertie requirements genrally include the following areas:

1) Access – to allow the DG owner access to the utility grid
2) Safety – to ensure the addition of the DG facility will not jeopardize the safety of the DG customer, the general public, and any operating or maintenance personnel.
3) Reliability – to ensure the reliability of the power system is maintained.
4) Power quality – to ensure the power quality of the power system is maintained.

For example, a typical utility operation may require the following:

- Maintain the voltage within +/- 10% of nominal
- Maintain frequency within +/- 0.1 Hz

- Maintain power quality by limiting voltage dips, sags, swell, flicker and harmonics
- Minimize interference with communication equipment
- Minimize outage times
- Prompt fault detection and fault removal to minimize equipment damage and voltage distortions
- Utilizing auto reclosing on substation feeder breakers to minimize outage times. DG must consider auto reclosing to ensure disconnecting of DG prior to reclosing.
- Provide a safe, de-energized condition when line work is being done or when there is a downed power line
- Islanded operation of DG generally not allowed
- Allowance of single-phase DGs must limit voltage unbalance caused by DG

These and other requirements are specified in guidelines and standards for generator interconnection to utility distribution systems.

Distributed Generators or Distributed Generation (DG)

Distributed Generation (DG) is an electric generation facility connected to the Distribution System through a Point of Common Coupling (PCC). Distributed Generation is a part of Distributed Resources (DR).

Distributed Resources (DR) are sources of real electric power that are not directly connected to the bulk power transmission system. It includes both generators and energy storage facilities.

Many names have been used for DR. Power Producer refers to anyone interconnected to the Wires Owner distribution system for the purpose of generating electrical power. Some of the common names used include Independent Power Producers (IPP), Customer Owned Generation (COG), or Non-Utility Generation (NUG) which are generation facilities not owned by the utility. In addition, Co-Generation (Cogen) facilities such as paper mills that produce power as a secondary function, can be a part of DR.

For the purpose of this paper DG will be used throughout. Wires Owner refers to the utility owning the Utility System.

Radial Distribution Feeder

DGs are applied to distribution systems. This paper will address those facilities connected to radial distribution lines or feeders, although many of the protection principles can be carried over to loop systems as well.

AC Power systems are configured of many different voltage levels, with no international standards. While voltage levels may vary, the levels considered for this paper fall into the distribution category. Typical voltage classifications are as shown:

Distribution	34.5 kV and lower
Subtransmission	34.5 – 138 kV
Transmission	115 kV and higher

The classes can also be subdivided into the levels shown:

High voltage (HV)	115 – 230 kV

Extrahigh Voltage (EHV)	345 –765 kV
Ultrahigh Voltage (UHV)	1000 kV and higher

Power lines can also be classified as either radial (or feeders) or as loop lines.

Radial lines or feeders have a positive-sequence source at only one terminal. Induction motors are not generally considered as sources. Typical feeders are distribution lines supplying power to non-synchronous loads. Thus, for line faults current is from the source end only. For ground faults on the line, current can flow from both ends, if they are both grounded. Tripping the positive-sequence source will de-energize the fault, but the ground sources must be tripped to clear the fault if there is zero-sequence mutual coupling from adjacent lines.

Loop lines have positive-sequence sources from two on more terminals. These are generally transmission lines, but may include distribution lines. Fault current contribution is from all sources, thus all sources must be tripped to clear both line and ground faults.

Distributed Generation

A typical DG connection to a radial distribution feeder is shown in figure 1.

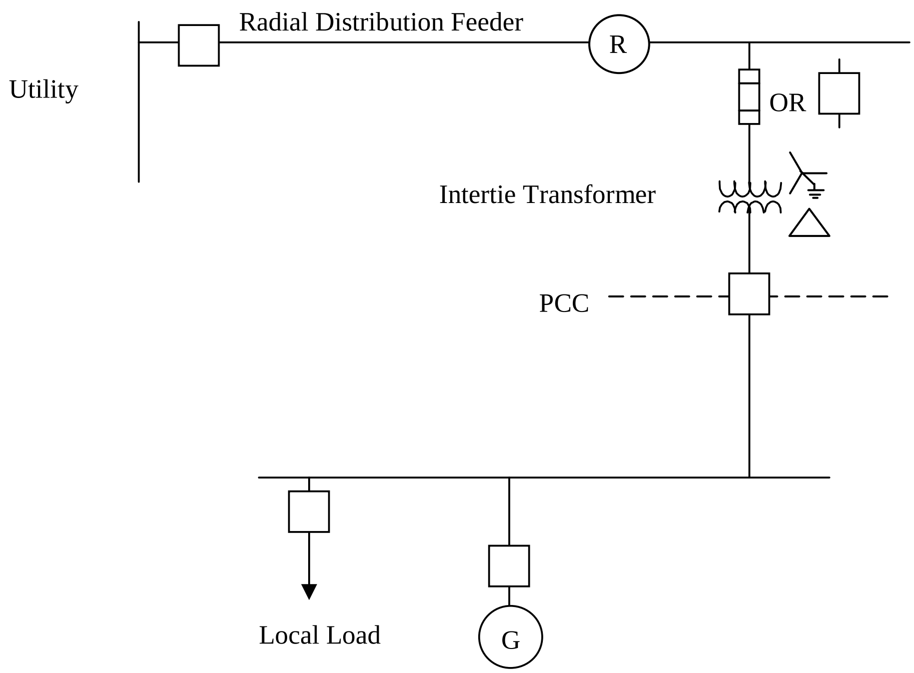

Figure1: Typical DG Connection to Radial Distribution Feeder

General Intertie Protection Requirements

Protection requirements will generally vary based upon the size of the DG and its load and the impact it may have on the connected feeder. If the DG is small and there is no export of power onto the utility feeder, the protection may be minimal. For larger DGs and when power is delivered to the utility system, the protection requirements can become more complex.

Protection requirements also vary and will require interface with the utility engineering personnel to determine what protection is required. Intertie protection protects the generator from damage from the utility system as well as protecting the utility system from damage due to the generation being connected. Protection is normally applied at the interconnection point. Some of the protection techniques that are used for the intertie are as follows:

Phase and ground fault protection – DGs must have protective devices to detect and isolate the DG for faults in the DG facility and may also be required to detect faults on the distribution feeder. The DG should coordinate with relays on the distribution feeder.

Over and under voltage – The DG must operate within established distribution levels. Relays must isolate the DG when the voltage is outside these levels. Under voltage relays are generally time delayed to prevent unnecessary tripping of the DG for external faults. The amount of delay time is a function of how far from nominal the under voltage condition is. Faster clearing times are required as the voltage level increases from the nominal level. These levels and clearing times will be defined in the standards being used. Inverse time under voltage relays or relays with two or more under voltage elements have been used. Over voltage relays may be instantaneous.

Over frequency and under frequency – Over and under frequency relays are applied to separate the DG from the utility system for frequency levels outside of prescribed limits. These relays are timed delayed depending on the level of frequency detected from nominal or on the rate-of-change of frequency above or below nominal.

Anti-islanding – Anti-islanding protection is used to prevent the DG from being connected to a de-energized utility feeder. If the DG is not removed from the system, the DG may be unable to maintain the required power quality to the power system customers.

If the DG is allowed to export power in parallel with the utility, and the DG capability can closely match the utility feeder load, traditional methods of anti-islanding protection may not be sufficient to prevent islanding of the DG. In this case, pilot tripping (transfer trip) may need to be employed.

Over and under voltage and frequency relays provide basic anti-islanding protection. Where the DG rating closely matched the distribution load, there may not be sufficient change in the voltage or frequency for these relays to operate. In this case, a transfer trip scheme may be necessary to ensure the DG is prevented from islanding.

Directional overcurrent relays may be required to detect faults in the interconnection transformer or on the utility distribution line.

Directional power relays may be required for anti-islanding. Where power export is not allowed, the directional power may be set to look either forward or reverse. When set to detect power export (reverse power), the relay may be set to trip at a level below the expected minimum utility feeder load that the DG would supply if islanded. When set to detect power import (forward power), the relay may be set to trip at a level below the minimum expected power import level.

Special interconnection protection – If the DG is large enough to affect the stability of the power system, out-of-step (78) or loss of synchronism protection may be required.

Inadvertent energization of utility system by DG and synchronization – The DG should not be able to energize a dead utility system. When connecting to a live utility system, the DG must properly synchronize to the utility to ensure the DG will not be damage. A synchronism check relay is used to ensure this.

Basic Interconnection Protection for Small-Sized DGs

The determination of so-called "small-sized" DGs may vary depending on the particular system to which it is attached.

For the purpose of this discussion, it is assumed that a small-sized DG will not export power, and, if islanded, will not be able to support the minimum utility feeder load. Therefore, over and under voltage and frequency elements may be sufficient.

The determination of what a "small-sized" generator is will generally be determined by the utility by way of intertie standards based on generator size and location.

Over and under voltage relays and over and under frequency relays are set to respond to abnormal voltages with clearing times determined by the standards being followed (e.g., IEEE standard 1547-2003 or similar). Table 1 shows an example of a typical requirement for response to abnormal voltages and frequencies.

Table 1: Example of Interconnection System Response Requirements

Response to Abnormal Voltages	**Clearing Time**
V< 50% (of nominal)	10 cycles or less
50%<V<88%	120 cycles or less
110%<V<120%	30 cycles or less
V > 120%	10 cycles or less
Response to Abnormal Frequencies	**Clearing Time**
F > 60.5 Hz	10 cycles or less
57.0(adjustable) < F < 59	Adjustable time delay
F < 57.0	10 cycles or less

Figure 2 shows basic intertie protection for small-sized DGs. In the case of loss of the utility, the intertie protection must separate the DG from the system prior to any reclosure by the utility devices. This will ensure the DG is not energized from the utility in an out-of synchronism condition.

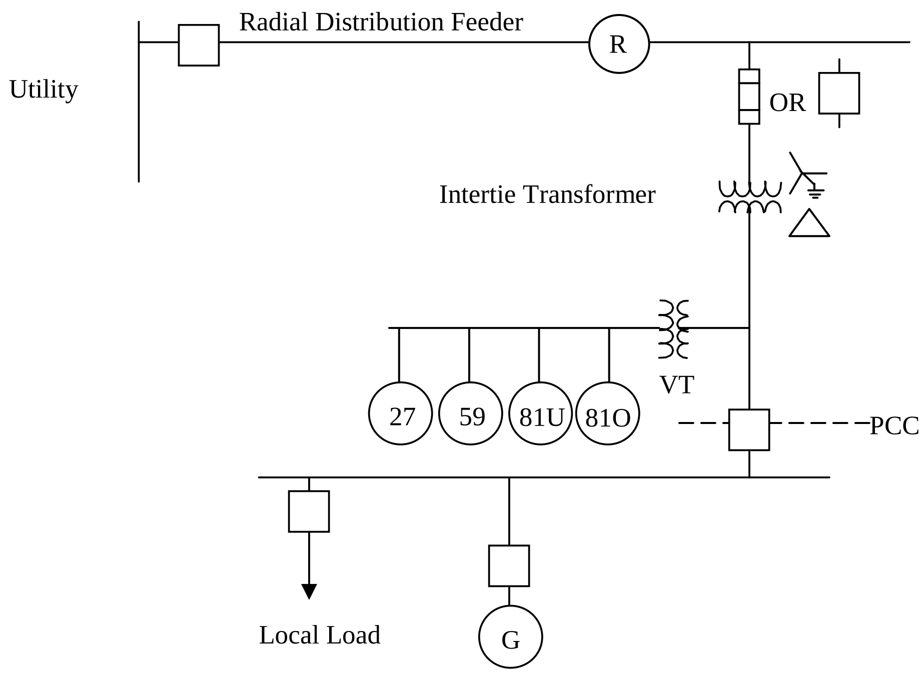

Figure 2. Basic Intertie Protection for Small DGs

Intertie Protection of Medium-Sized DGs

Larger DGs will include the same relays that the small DGs employ. In addition, these larger DG facilities may require protection to isolate the DG for faults occurring either in the DG itself or on the distribution system. The DG protective devices will generally be required to coordinate with protective relays on the distribution system, unless otherwise agreed.

Non-directional overcurrent relays (51) are generally used on the low side of the interconnecting transformer main breaker to detect bus and feeder faults at the customer facility.

With generation added to the customer facility, the non-directional overcurrent protection will still detect these bus and feeder faults. However, they may not be sensitive enough to detect the DG current contribution to faults in the interconnecting transformer or on the utility distribution line. Directional overcurrent protection (67) needs to be set to detect faults on the high side of the interconnecting transformer and out onto the utility feeder.

Directional power relays (32) may be added to add to anti-islanding protection. One way this can be done is by detecting power export (reverse power flow toward the utility) and setting the relay to trip for power flow less than any a minimum load level that may be on the utility feeder.

A directional power relay may also be used to detect power import (forward power flow toward the DG) and setting the relay to trip for power flow less than a minimum power import level.

Phase current unbalance protection (46) and phase voltage unbalance detection (47) may also be added if the sensitivity of under and over voltage elements is not sufficient to trip the intertie breaker to prevent equipment damage due to negative sequence voltages or currents.

Directional negative sequence overcurrent (67Q) relays or voltage controlled overcurrent relays (51V) may also be used to provide increased sensitivity for unbalanced faults on the utility feeder.

Synchronism check (25) is required to ensure the DG will not connect to the power system out-of-synch. It may be applied at the primary-side transformer breaker, the secondary-side transformer breaker, or both.

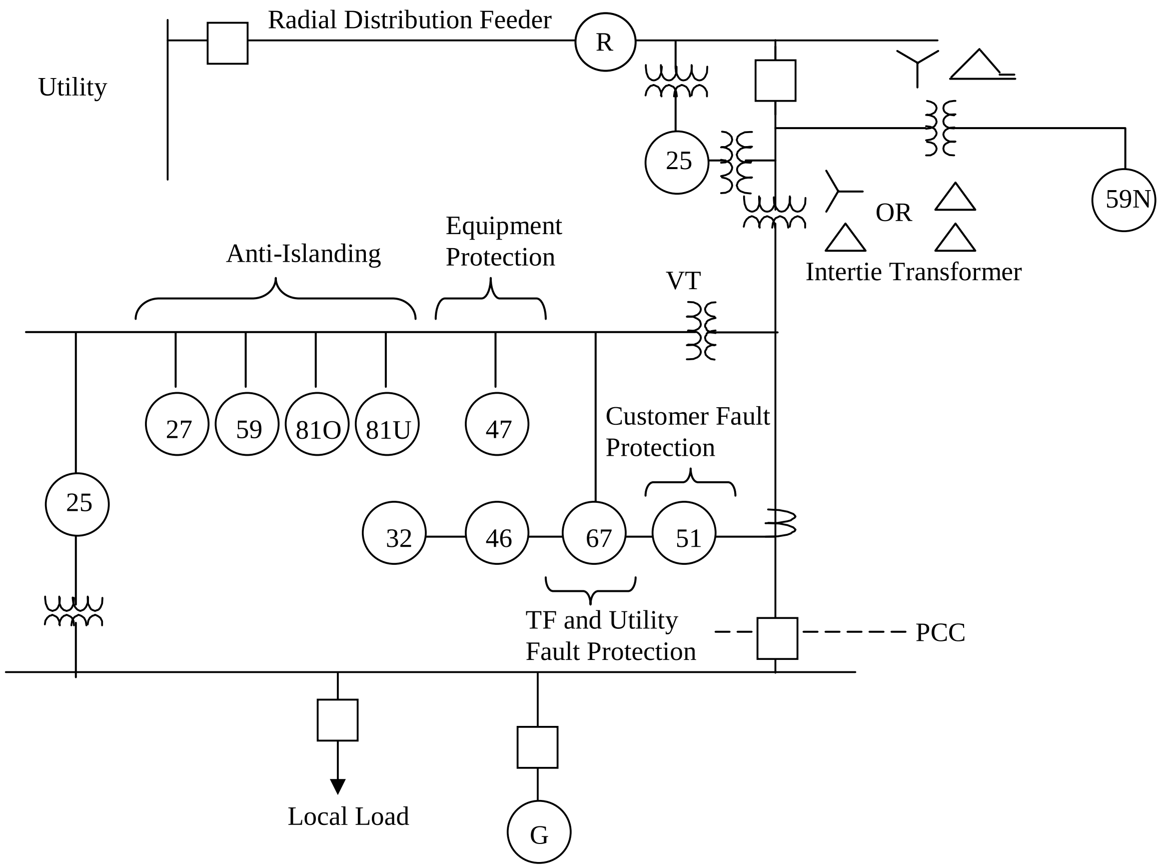

Figure 3. Basic Intertie Protection for Medium-Sized DGs.

Interconnecting Transformer Primary Ungrounded

For a phase-to-ground fault on the feeder, when the utility breaker isolates the fault, the voltage on the ungrounded system will experience a voltage shift as shown in figure 4. Thus, when a phase-to-ground fault occurs, the unfaulted phases are increased $\sqrt{3}$.

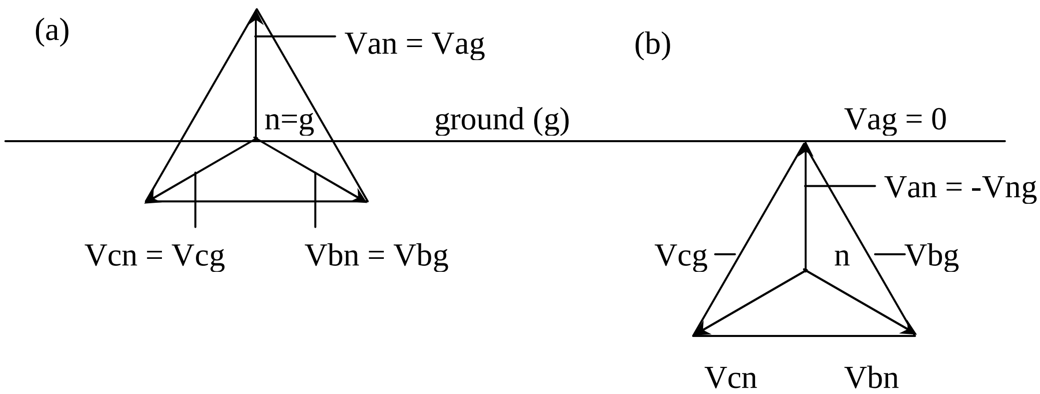

Figure 4: Voltage Shift for a phase-a-to ground fault on an ungrounded system: (a) normal system; (b) phase a *solidly grounded.*

One way to detect this condition is to connect a voltage-sensing relay to 3 VTs in a broken delta configuration as shown in figure 3 and figure 5, thus monitoring zero sequence voltage. The resulting unbalance can then be detected by connecting an over voltage relay across the broken delta connection, along with a resistor that is used to reduce the possibility of ferroresonance (figure 5).

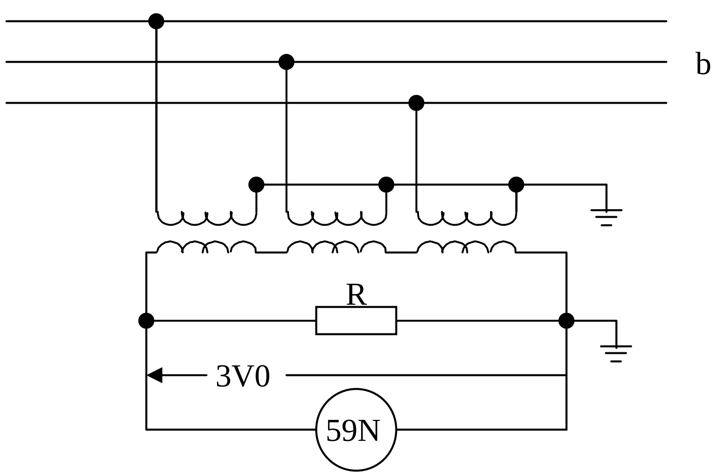

Figure 5. Voltage ground-fault detection using three voltage transformers connected wye – ground – broken delta

During normal conditions, the voltage unbalance will be minimal. The zero sequence voltage will then be minimal, 3V0 = Vag + Vbg + Vcg (figure 6a.).

When a phase-ground fault occurs the faulted phase voltage collapses and the $3V_0$ voltage across the 59N increases to as much as full secondary phase-ground voltage. Primary voltage increases as much as 1.73 x normal line-to-ground voltage (figure 6b).

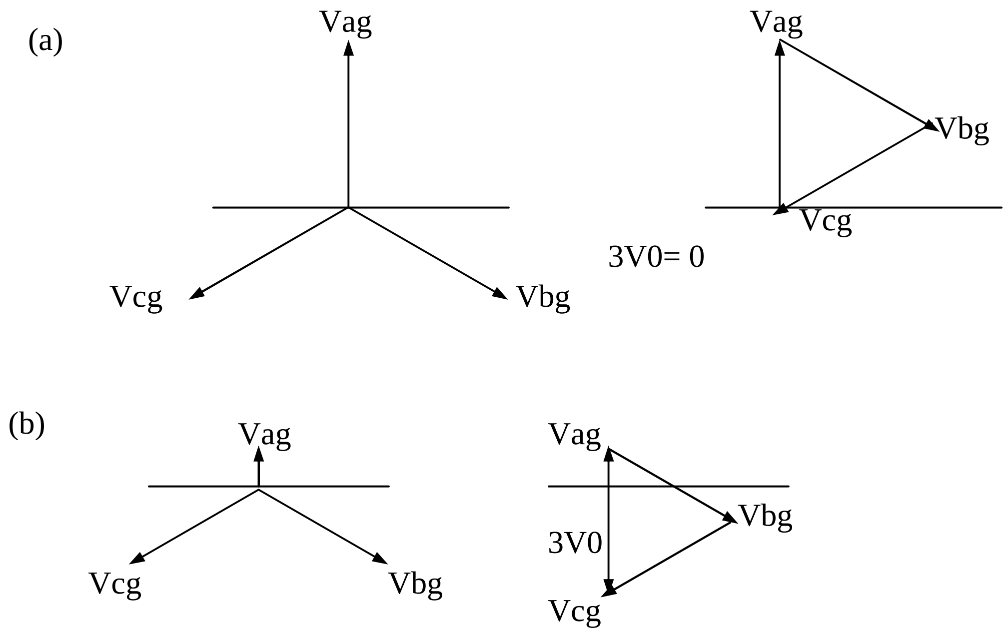

Figure 6: Voltage phasors for a balanced three-phase distribution system (a), and during a phase a-to-ground fault (b).

Ground fault detection can also be accomplished using a single-voltage transformer connected phase-ground to the primary (figure 7). The resistor is added to prevent ferroresonance. If a fault occurs on phase B voltage on the relay collapses and the undervoltage element (27) will operate. If the fault is A or C phase the voltage on Phase B will increase as high as 1.73 x normal and the overvoltage element (59) will operate.

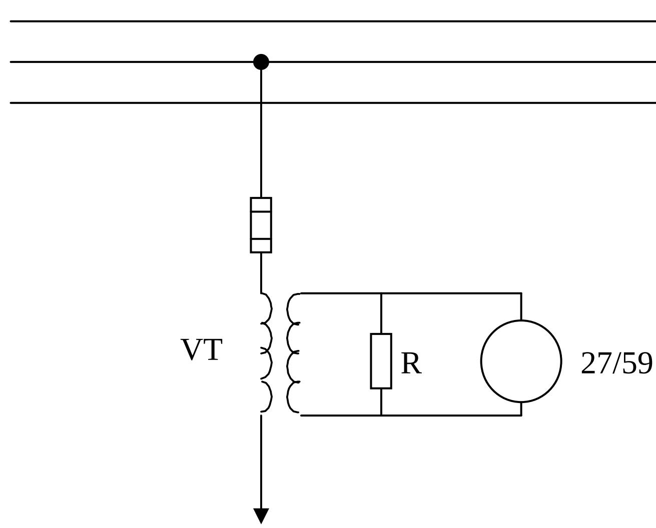

Figure 7: Voltage ground detection using single voltage transformer

Intertie Protection of Medium-Sized DGs. Interconnecting Transformer Primary Grounded

If the interconnection transformer is grounded on the utility side, ground current can be supplied to a fault on the distribution feeder by the interconnecting transformer. Utility feeder phase fault protection at the intertie is provided by instantaneous and time overcurrent relays on the primary of the intertie transformer (50/51). Ground fault protection at the intertie is provided by a time overcurrent relay in the neutral of the intertie transformer (51N).

The ground source provided by the intertie transformers may cause undesirable relay operation at the utility substation breaker (B) or at the recloser on the feeder (R) for faults on the distribution feeder or adjacent feeders. Directional overcurrent relays may need to be applied to the utility feeder breakers to ensure proper relay operation for faults on the feeder. Figure 8 shows interconnection protection for a DG connected through a transformer with the primary grounded. The current reversal is shown for faults on the utility feeder and for ground faults on adjacent feeders.

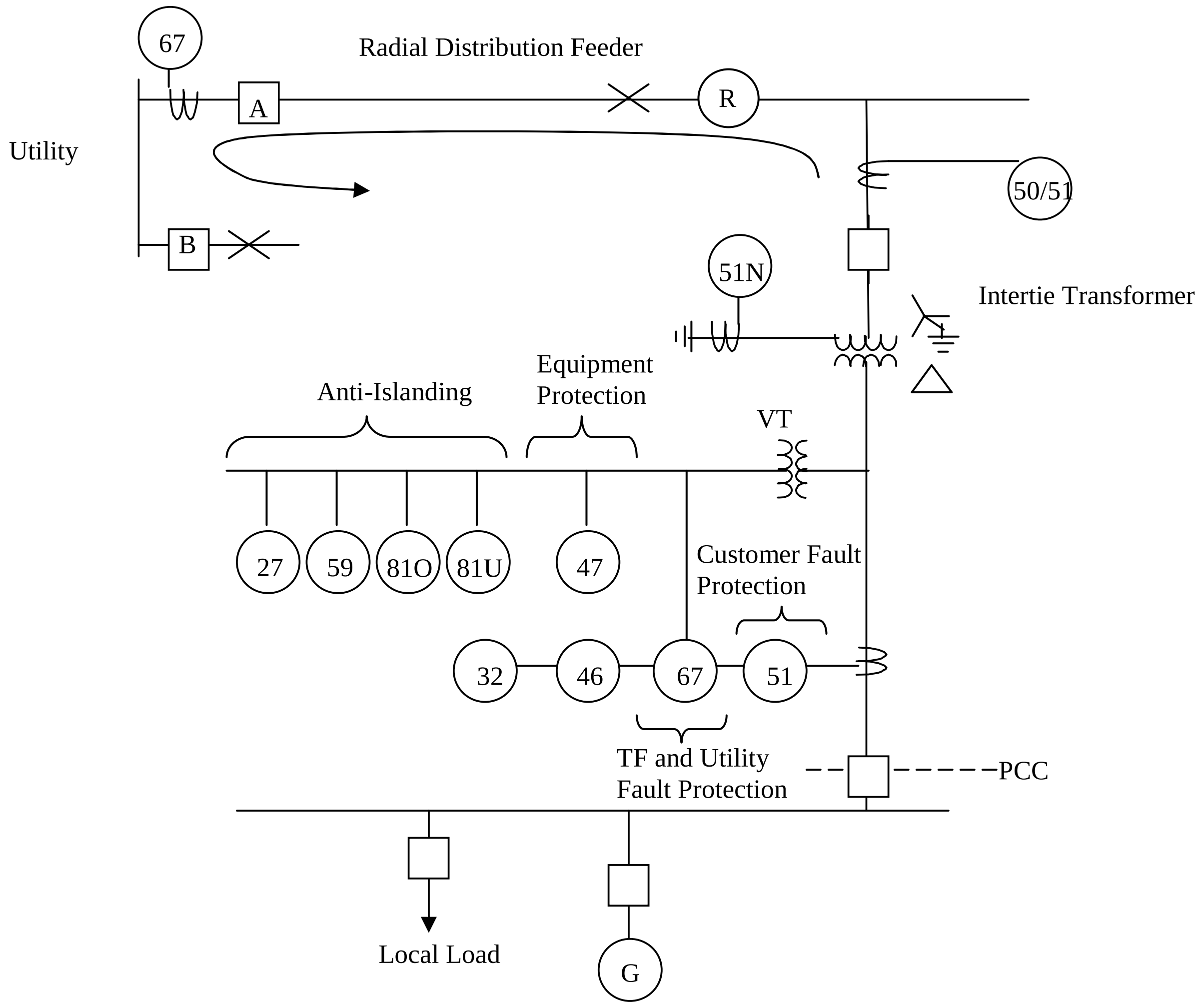

Figure 8. Basic Intertie Protection for Medium-Sized DGs. Transformer Primary Grounded

If the DG is allowed to export power in parallel with the utility, and the DG capability can closely match the utility feeder load, traditional methods of anti-islanding protection may not be sufficient to prevent islanding of the DG. In this case, pilot tripping (transfer trip) may need to be employed. This requires a transfer trip transmitter at the utility breaker and a transfer trip receiver at the DG facility.

In Closing

Distributed generation installations on distribution feeders appear to be a popular alternative to larger, utility-owned fossil fuel and nuclear plants for the near future and possible for a long time to come. These installations will continue to present protection challenges of ensuring a safe and reliable power system.

Initiatives like those of IEEE Std. 1547-2003 will continue to discover viable solutions to the many challenges of distributed generation as utilities continue to update intertie standards and guidelines.

Even with intertie standards becoming more defined, each distributed generation installation will still require the engineer to evaluate these applications on a case-by-case basis.

Author Biography

Gerard Gustafson worked nine years at Central Maine Power Company before joining Basler Electric in June of 1997. His work at Central Maine Power was with the substation operations department, performing system protection engineering and technical training functions. Mr. Gustafson received a BSEE from the University of North Dakota in 1985 and is a Senior Regional Application Engineer for Basler Electric Company based near Minot, North Dakota. Mr. Gustafson is a member of IEEE.

References

1) "Protective Relaying Principles and Applications – Second Edition", J. Lewis Blackburn, Copyright 1998 by Marcel Dekker, Inc.
2) "Draft Standard for Interconnecting Distributed Resources With Electric Power Systems", IEEE P1547, Draft #10.
3) "Protection of Independent Power Producer Generators Using Digital Technology", Charles J. Mozina, Beckwith Electric Co., Inc.
4) "Wisconsin Distributed Generation Interconnection Guidelines", Wisconsin Interconnection Collaborative, Draft 5.9, 6/28/98.
5) "The DG Book – Guidelines for the Interconnection of Distributed Resources to the ComEd System", Copyright 2001 by ComEd.

Back to Table of Contents