Interconnection of Distributed Energy Resources in Secondary Distribution Network Systems

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1
INTRODUCTION

This white paper has been developed to introduce secondary distribution networks and the ongoing issues, best practices and guidelines at various utilities throughout the United States that relate to the integration of distributed energy resource (DER) technology. Based on experience gained and issues encountered, several conclusions and recommendations are also presented.

EPRI has done extensive work assessing the degree of difficulty that can be expected for integrating a particular DER installation into the utility system relating to interconnection practices, distribution system impacts, and communication and control possibilities. This work has been described in the report *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems* (1000419). These interconnection practices and distribution impacts were then also incorporated into an EPRI software tool with the latest version published as *Distributed Resources Integration Assistant, Version 4.0* (1008428). However, the main body of work on integrating DER systems into distribution systems covered in the above references has focused primarily on radial distribution feeders and not on secondary distribution networks.

Though most applications of DER systems have occurred on distribution radial feeders, they also have been connected to distribution secondary networks. Preliminary assessments show that there is a high number of potential applications of DER in urban cities where these networks exist. As such, it has become increasingly apparent to DER developers, utilities and governing agencies that the issues, challenges, and best practices for interconnecting DER into distribution secondary networks need to be better understood, tested and developed so that recommended solutions can then be safely implemented in a consistent and prudent manner.

To present the discussion on interconnection of DER in secondary network systems, this white paper has been divided into the following chapters:

Chapter 1: Introduction

Chapter 2: Secondary Distribution Network Overview

Chapter 3: Interconnection Issues

Chapter 4: Existing Interconnection Guidelines

Chapter 5: Conclusions and Recommendations

2
SECONDARY DISTRIBUTION NETWORK OVERVIEW

Power System Design and Operation

The major role in determining the interconnection requirements and the system impact issues that are of concern will be played by not only the type of DER technology that is employed, but also the type of distribution system to which it is connected. There are many different types of power distribution systems and equipment. Each type of system has its own special requirements that must be addressed.

Voltage Levels, Design Philosophies

Customers are normally served from either radial distribution feeders or secondary networks. Before we discuss secondary networks, we will discuss radial feeders to provide a means of comparing and contrasting these two topologies.

The distribution primary voltage classes are 5, 15, 25, or 35 kV. The 15-kV class voltage level is the most popular, comprising more than 80% of all distribution circuits within the U.S. Within that class, the nominal voltages of 12.47, 13.2, and 13.8 kV are the most popular distribution primary voltages. These circuits typically have main feeders of from 5 to 25 km in length with various three-phase and single-phase branches from the three-phase main line.

The loading of such circuits varies greatly; however, under typical operating conditions, 4 to 6 MVA is representative of the peak loads on most 15-kV class feeders. Feeders at 25- and 35-kV voltage levels carry correspondingly higher loads of 7 to 10 MVA and 10 to 16 MVA, respectively. These would represent typical loading, but the maximum capacity of these circuits is somewhat higher depending on conductor size and circuit length.

Typically, the larger commercial or industrial loads that are served from radial feeders maybe metered at primary voltage. However, there are usually no primary metered services available from network feeders. For most customers, the primary voltage is stepped down with distribution transformers to the “secondary” or low-voltage level for delivery of power to customer loads on the system. (Low voltage is defined in the ANSI/IEEE standards as less than 600 Vrms.) Common secondary voltages for three-phase, wye-grounded services are 480Y/277 volts or 208Y/120 volts. The first number identifies the phase-to-phase voltage and the second identifies the phase-to-neutral voltage. Phase-to-neutral voltage is related to the phase-to-phase voltage by the square root of three *if the voltages are balanced.* These three-phase voltages serve most commercial buildings. For single-phase service, which serves most residential customers, 240/120 volts is the most common practice.

Distribution feeders come in many different configurations and circuit lengths, but most share many common characteristics. **Figure 2-1** shows a typical radial distribution feeder, and **Table**

2-1 shows typical parameters of a radial distribution circuit. For more information on distribution systems, refer to [1,2,3,4].

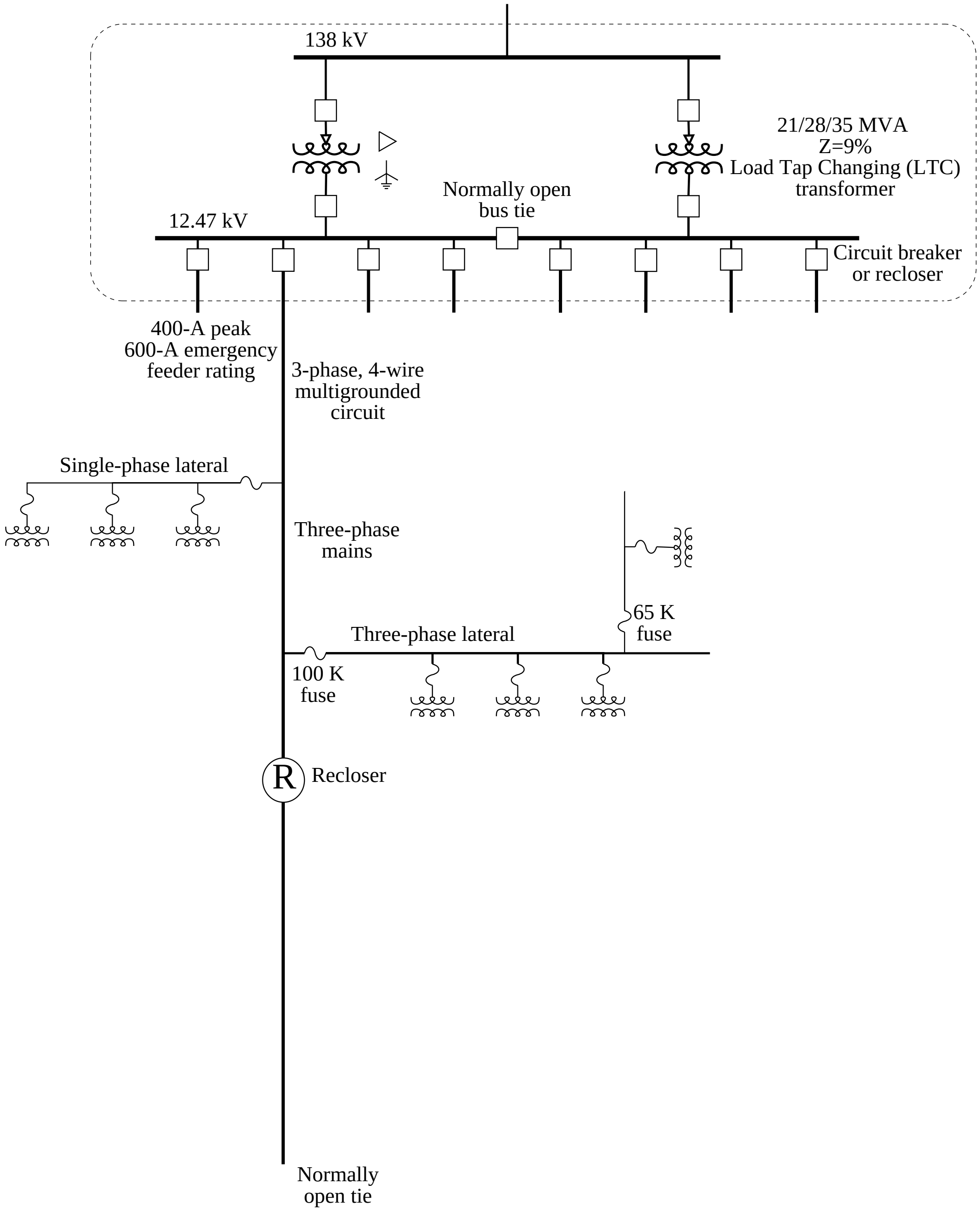

Figure 2-1
A Typical Distribution Substation and a Typical Radial Feeder

Station and Feeder Characteristics	Most common value	Other common values
Voltage	12.47 kV	4.16,4.8,13.2, 13.8, 24.94, 34.5 kV
Substation transformer	2	1 – 6
Substation transformer size	21 MVA	5 – 60 MVA
Number of feeders per bus	4	1-8
Peak current	400 A	100 – 600 A
Number of customers	400	50-5000
Length of feeder mains	4 miles	2-15 miles
Length including laterals	8 miles	4-25 miles
Mains wire size	350 kcmil	4/0 to 795 kcmil
Lateral wire size	#2	#6 to 2/0
Lateral peak current	25 A	5 – 50 A
Lateral length	0.5 miles	0.2 to 5 miles
Distribution transformer size (1ph)	25 kVA	10 to 75 kVA

Table 2-1
Typical Distribution Circuit Parameters

Low cost, simplification, and standardization are all important design characteristics of distribution systems. Very few non-standard components are installed on a distribution circuit. Standardized equipment and designs are used wherever possible. Pre-approved engineering guidelines, equipment, and operational methods are used for most of distribution planning, design, and operations.

Distribution System Networks

The *network* is the most sophisticated type of distribution system. It does not employ a radial power flow concept but instead relies on the fact that each load receives its power from several parallel paths operating simultaneously. This is achieved by using a grid of interconnected primary or secondary lines to serve the loads connected to it. For radial systems, the term connecting to the “grid” is used loosely and is really a misnomer given the “fanned” nature of radial power flows on radial systems. For network systems, it is literally true to say that a DER *is connected to the grid.*

Networks with an interconnected grid at the primary voltage level are referred to as *high-voltage (or Primary) networks*. When the interconnected grid is at the secondary level (600 volts or less), it is a *low-voltage(or Secondary) network*. In some instances, there can be combined high-voltage and low-voltage networks. Network systems provide excellent service reliability but at premium design and maintenance costs. Network systems may be economical where the load density is very high and there is increased need for reliable service, such as in urban areas serving large loads. Most networks are low-voltage (Secondary) Networks.

For low-voltage networks, the secondary sides of the service transformers are networked together. Each of the service transformers is fed from a different primary feeder. There are basically two types of low-voltage networks—the Grid Network and the Spot Network. The grid network can serve a large area (as large as 10x10 blocks in a city). The spot network feeds one major load, such as a high-rise building, and is basically established within the building itself. The spot network is generally fed by three to five primary feeders that are connected to the high-voltage side of the network transformers (see **Figure 2-2**).

The secondary grid network is usually fed by five to ten primary distribution primary feeders (such as 12.47-kV circuits) via network transformers at multiple locations. **Figure 2-3** shows a secondary grid network comprised of 9 transformers fed from 3 primary feeders. Network Protectors provide back feed protection of the network against a sustained primary feeder fault for both the spot and grid networks. The primary circuits are generally sized with either N-1 or N-2 redundancy in mind. This means that if any one or two primary cables fail, the remaining feeders can pick up the load without shutting down the network. More conservative network designs employ the N-2 contingency. Networks operate at 480Y/277 V or 208Y/120 V in the U.S.

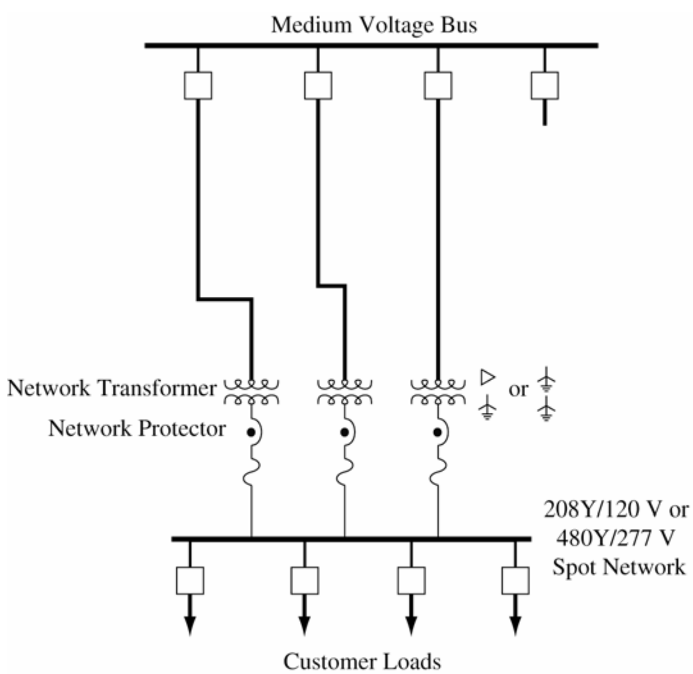

Figure 2-2
Spot Network Connections

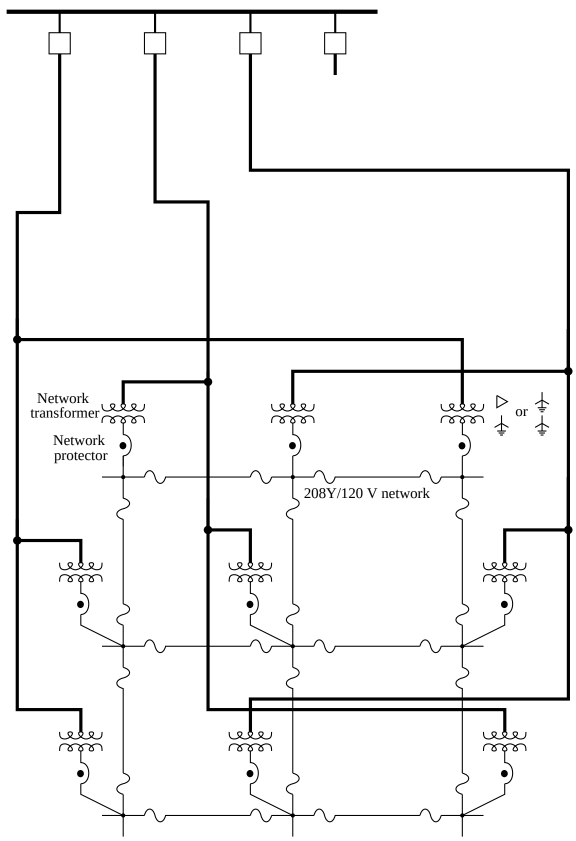

Figure 2-3
Portion of Secondary Grid Network

Major cities, such as New York, Seattle, and Chicago have extensive distribution network systems. However, even smaller cities, such as Albany or Syracuse, New York, or Knoxville, Tennessee, have small spot or grid networks in downtown areas.

3

INTERCONNECTION ISSUES

There are many issues related to the interconnection of DER in existing power systems. This chapter provides a brief discussion of those issues specific to interconnection of DER in spot and grid networks. This discussion should not be considered exhaustive since field is developing rapidly. New issues, as well as solutions, are being identified on a regular basis.

Reverse Power Method of Protecting Networks Prevents Power Export by Design

Low-voltage secondary networks are distribution systems that are used in most major cities. The secondary network operates at customer voltage, usually 480Y/277 V or 208Y/120 V in the U.S. The secondary network is connected in a grid rather than the normal radial system. Several (usually 4-6) primary distribution circuits, such as 12.47-kV circuits, feed a secondary network. If any of the primary distribution circuits fail, the others will carry the load without causing an outage to any customers. For this reason, the system is considered very reliable. To isolate the failed circuits, secondary networks are equipped with network protectors which are installed on the secondary side of each network transformer. These network protectors will open when a reverse power flow through them.

Distributed generators can cause peculiar problems on a secondary network. For example, if the distributed generation output is large enough, it could cause reverse power flow through the protectors. This will trip the network protectors, leading to an outage as shown in **Figure 3-1**. Also, in case of an islanded operation, an improper closure of a network protector could cause severe damage. Under light load, a distributed generator (this may include backup generation using a closed transition) may eventually cause all of the network protectors to trip, thereby creating an islanded condition with the similar potential hazards of improper or, out of synchronism, closure of any network protector.

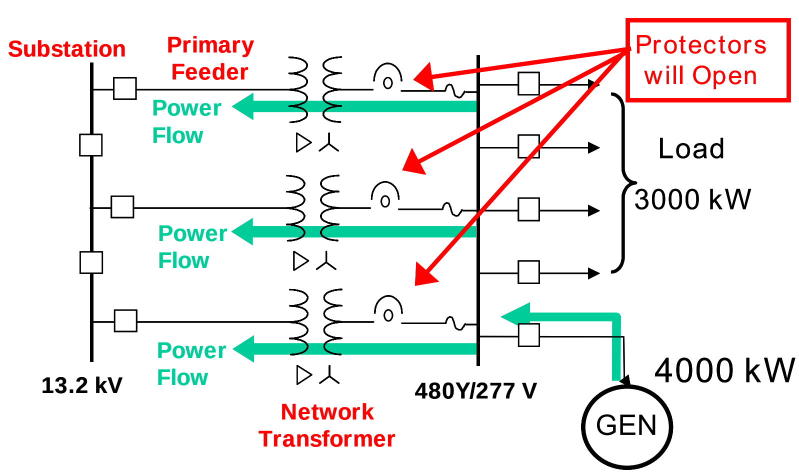

Figure 3-1

Network Protectors Can Be Damaged Under Islanding Conditions

During island conditions, the voltage across an open network protector can exceed the ratings of the device. This voltage is the result of the island being out of synchronism with the utility. If a network protector is called upon to operate under this condition, it may fail.

Islands can form on spot networks by either of the following scenarios:

1. The generation on the network exceeds the load, so the network protectors all trip on reverse power flow. Of significant concern are the backup generators that are tested with a make-before-break transition. The generators may be sized to carry much of the facility in a spot network.
2. Under light load where only one network protector is closed, a fault upstream of that network protector will cause the network protector to trip (assuming the unit is large enough to provide sufficient fault current contributions). Even if the generation is less than the load on the island, it may be maintained for a long enough time that one of the protectors closes back in.

Network protectors in normal applications must have a sensitive reverse-power-trip setting (usually a few tenths of one percent of the kVA rating of the associated network transformer). If a generator is operated in parallel with the network and the network protectors are equipped with the standard complement of relays (master and phasing), all of the network protectors may open. Should this happen, the network bus and loads are energized by the generator, and the secondary side of each network transformer is energized from the utility primary feeders as shown in **Figure 3-2**.

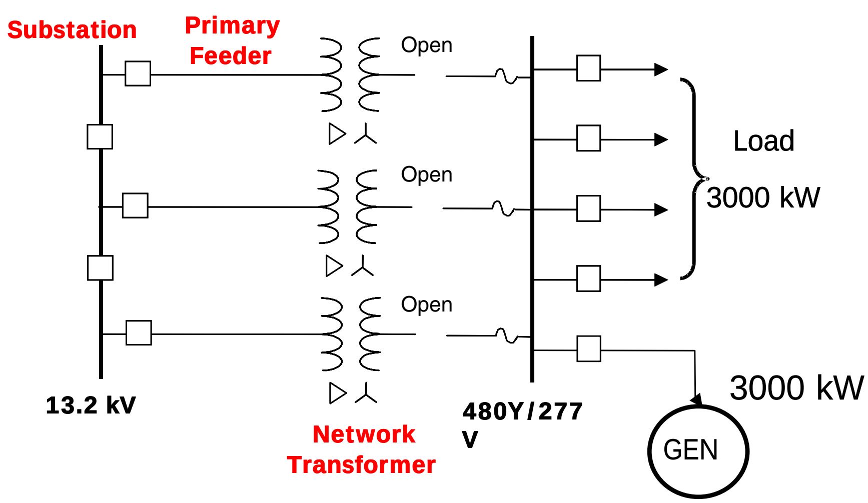

Figure 3-2
Three Source Spot Network with Generator

Once the two systems are separated, they are no longer synchronized and will swing relative to one another at a slip frequency. At an open protector, the transformer-side voltage will rotate relative to network voltage causing phasing voltage at the open protector to vary in both the magnitude and the relative angle with respect to the network voltage. Network protector relays were never intended to operate under conditions where the voltages on the opposite sides of the protector are not synchronized. With the systems swinging, the phasing voltage may pass into the close region of the relays that control protector closing where the protector may initiate closing. During the finite time required for the protector to close, the utility system and the network bus supplied by the generator may swing far out of phase. Out of phase closure typically trips the protector due to reverse power flow or overcurrent. The out-of-phase closing may also damage the generators and the network protectors. Furthermore, it has been suggested that separation of 2 energized systems by opening of a network protector could damage the protector or cause it to fail. Network protectors have not been intended for separation of energized systems and have not been tested for this condition. They may fail to interrupt successfully, or be damaged during a voltage restrike across their open contacts when the voltages on each side of the open contacts become 180 degrees displaced with respect to each other (making the recovery voltage twice the line-to-ground voltage).

Network Protectors May Inadvertently Open Under Fault Conditions, Isolating the Network

Figure 3-3 shows the system configuration when the output of the generators is nearly equal to the total load on the network. Under these conditions, network protector NWP 2 and NWP 3 open as they see reverse real power flows of several tenths of one percent of the kVA rating of their transformer. NWP 1 is closed during a power flow into the network. If the output of the generator is slowly increased, there would be a reverse power flow in NWP 1, which would trip if equipped with the normal relay complement.

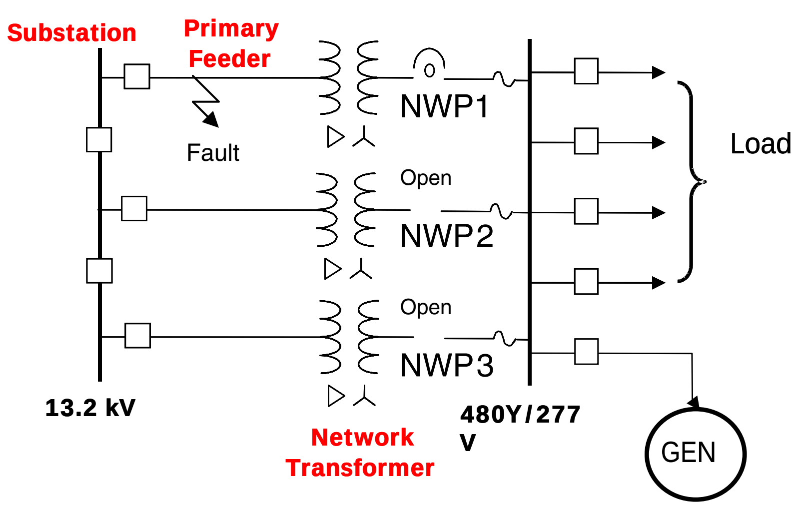

Figure 3-3
Three-Unit Spot Network with Generation Operating in Parallel with the Network

A possible event of concern in **Figure 3-3** would be a fault on primary feeder 1 when the generation is operated in parallel and only NWP 1 is closed. If a three-phase fault occurs on primary feeder 1, the generator can produce a reverse power flow in NWP 1. In addition, depending on generator size and impedances, the current back fed to the fault can be above the maximum instantaneous overcurrent relay pickup (250% of protector CT rating). Thus, it is conceivable that NWP 1 could trip in 3 to 4 cycles, before or concurrent with tripping of generator breaker. Meanwhile the voltage on the network bus is decaying. The closing relays in NWP 2 and NWP 3 may initiate closing of these protectors. By the time NWP 2 and NWP 3 close, NWP 1 would be open, and possibly the generator will still be feeding the network bus. When NWP 2 or NWP 3 closes, it could be significantly out of phase from the voltage at the generator, damaging the generator, and network protectors.

A time delayed tripping scheme to only detect generator contribution could be used to prevent the opening of network protectors during momentary power reversals. This would give time for the generator protection to trip, removing the reverse power condition. This constitutes design of a separate tripping scheme with separate relay setting for low level faults as the tripping or the detection of high fault currents should not be delayed.

Upgrading, or Replacing, Existing Network Protectors May be Impractical Due to Physical Space Considerations

The solutions to many of the problems associated with the interconnection of DER into secondary networks involve either upgrading the relaying components of existing protectors, or replacing of the protectors with newer units. Many existing protectors are located in confined spaces in underground vaults. In such cases, physical space may be a major consideration. New network protectors, designed to meet the requirements of DER interconnection, may not be physically compatible with existing installations. Similarly, upgraded relaying packages may be physically unable to be applied in some cases.

Network Protectors May Cycle in Some Conditions

Under certain light load conditions, network protectors may cycle (repeated opening and closing) when DER is operating. Slight differences in the impedances of network transformers, and/or the supply of the network from more than one medium voltage bus can cause some network transformers to carry more load than the others. In light load conditions, particularly with a DER providing generation to offset load, one or more network protectors may open. In a short time, the protector may close. This cycle can continue, reducing the protector life as well as the reliability of the network since one or more sources may be disconnected at times.

Network Protector May Experience "Pumping" (multiple reclose attempts)

If a network protector opens and isolates the network from the rest of the power system, the network protector may repeatedly attempt to reclose the protector. This is a problem when the generator is capable of powering the network with all of the protectors open. In such an islanded condition, the network protectors may reclose when the phasing voltage enters the controls close region. If the close is successful, the load condition that caused the opening in the first place will still be present, and the protector will open. Each time the network protector recloses, there is a chance of damage. The repeated reclose attempts may damage the network protector or ancillary equipment.

DER Contribution to Fault Current May Exceed Equipment Ratings

The use of DER technologies that are capable of supplying fault current, particularly synchronous generators, may result in the available fault current exceeding the rating of network equipment. Secondary networks generally have high available fault current levels. Any source that can increase the fault current levels is of concern to operators of secondary networks. In particular, the ratings of network protectors may be exceeded. Network protectors are not designed to interrupt fault current with a high X to R ratio. Synchronous machines are cable of producing fault currents with high X to R ratios, and therefore may be incompatible with the ratings of the network protectors.

4

EXISTING INTERCONNECTION GUIDELINES

The development of interconnection guidelines for Distributed Energy Resources in secondary networks is ongoing. A few states have adopted rules for secondary network interconnection. Some states are actively involved in developing rules related to secondary networks. This is definitely a time of flux with respect to this issue. Regulators and utilities are trying to adapt to the results of ongoing research and development in the area of integration of DER in secondary networks. The following is a brief discussion of the existing rules, either of state regulatory agencies, or utilities, related to the application of DER in networks.

California

California's Rule 21 standardized the process for application of DER in the state. A Rule 21 Working Group has been formed to study the impact of DER on secondary networks and to recommend regulations related to these installations. Currently, California Rule 21 contains language requiring an engineering study to consider the application of DER in networks. At present, DER connected to networks is not allowed to go through the short process. Instead, it must go through an engineering study process on a case by case basis.

PG&E

PG&E has developed some preliminary guidelines for the installation of DER into their secondary networks. They operate the largest network system in California. The guidelines are not final rules and are subject to further debate and modification. At this time PG&E has 2 basic requirements for interconnection of a DER to its spot secondary network.

1 – A time delayed, tripping scheme for detection of low level faults to prevent instantaneous tripping of the protectors for out of section (known as adjacent feeder faults).

2 – Direct tripping of all connected DER when the number of closed network protectors fall below 50% of the installed network protectors. This requirement complies with section 4.1.4.2 of the IEEE 1547 Standard. **Table 4-1** shows the minimum number of network protectors that must remain closed in order for the DER (or DG) to operate. Implementation of item 2 would require a direct tripping scheme between the network protector status and the generator breaker. At the time of this writing, PG&E is using a programmable controller to monitor network protector status and to initiate tripping.

Quantity of Network Protectors in Vault	Minimum Number of Closed Protectors Required in Order for DG to Operate
2	2
3	2
4	2
5	3

Table 4-1
Network Protector Requirements in PG&E Guidelines

Massachusetts

Massachusetts has formed the Massachusetts DG Collaborative Online Resource Center to aid in the development of standardized rules for the interconnection of DER. This group is involved in investigating the requirements necessary to safely, and economically, interconnect DER in secondary networks. The current rule in force in Massachusetts is given in *D.T.E. 02-38-B: Investigation by the Department of Telecommunications and Energy on its own motion into Distributed Generation*.

These rules spell out two different procedures that apply to spot networks: the Simplified Process and the Standard Process.

The “Simplified Process” applies to qualified inverter-based facilities with a power rating of ten kilowatts (“KW”) or less, on a radial system or spot network (under certain conditions and using a UL 1741 certified inverter) (id.).[7,8] In addition, the facility’s capacity must be less than 7.5 percent of the circuit’s annual peak load (id.). The interconnection for the Simplified Process timeline is a maximum of 15 business days, and there is no fee required for radial interconnection (id.).[9]

The “Standard Process” applies to either the radial or network system for all facilities not qualifying for either the Simplified or Expedited Processes (id.). The interconnection timeline for the Standard Process is 125 to 150 business days,[13] and the application fee is the same as for the Expedited Process, plus the cost of applicable studies and witness tests (id.).

Qualified inverter-based facilities on spot networks may use the Simplified Process when the aggregate facility capacity is less than one-fifteenth of the customer’s minimum load.

The Collaborative noted that interconnecting DG to secondary networks poses certain additional challenges; therefore, it agreed to: (1) allow certain small inverter-based facilities on spot networks to use the Simplified Process; (2) set a goal to seek expeditious and cost-effective approaches for interconnecting on a spot and area network; (3) form a technical group under the umbrella of the ongoing Collaborative to study network interconnection experience and procedures; and (4) provide regulators, customers, DG providers, utilities, and others with a clear explanation of the opportunities, challenges, and potential solutions posed by interconnecting to networks.

Figure 4-1 is found in *D.T.E. 02-38-B (2004) Attachment A: Uniform Standards for Interconnecting Distributed Generation - Model Tariff.*

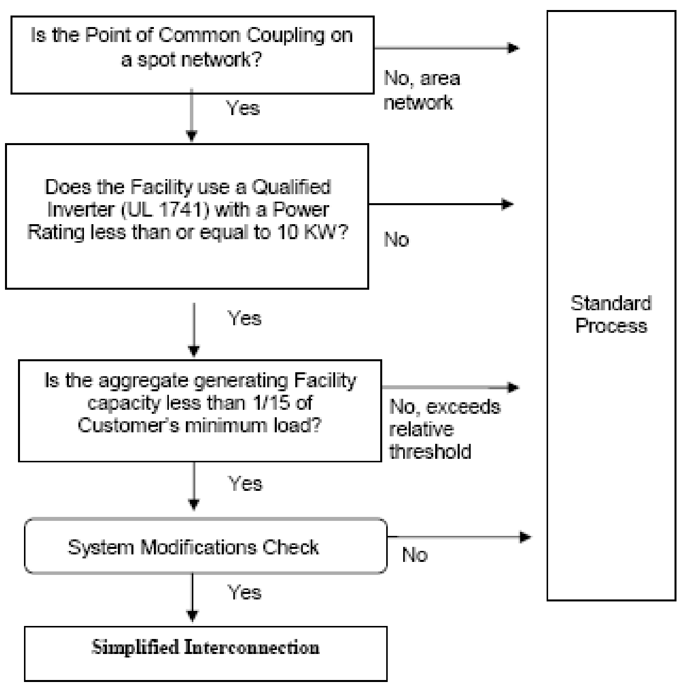

Figure 4-1
Simplified Interconnection to Networks

New Jersey

The rules outlined by the New Jersey Board of Public Utilities related to the interconnection of DER into secondary networks are quoted below. Of particular interest is the requirement to allow the interconnection of inverter based DER into networks as long as they meet a maximum size requirement. Texas is the only other state with such a requirement. The following is quoted from *N.J.A.C. 14:4-9 Net Metering and Interconnection Standards for Class I Renewable Energy Systems:*

> 1. For a customer-generator facility that will be connected to a spot network circuit, the aggregate generation capacity connected to that spot network from customer-generator facilities, including the customer-generator facility, shall not exceed 5% of the spot network's maximum load;
>
> 2. For a customer-generator facility that utilizes inverter based protective functions, which will be connected to an area network, the customer-generator facility, combined with other exporting customer-generator facilities on the load side of network protective devices, shall not exceed 10% of the minimum annual

load on the network, or 500 kW, whichever is less. For the purposes of this paragraph, the percent of minimum load for solar electric generation customer-generator facility shall be calculated based on the minimum load occurring during an off-peak daylight period;

3. For a customer-generator facility that will be connected to a spot or an area network that does not utilize inverter based protective functions, or for an inverter based customer-generator facility that does not meet the requirements of 1 or 2 above, the customer-generator facility shall utilize reverse power relays or other protection devices that ensure no export of power from the customer-generator facility, including inadvertent export (under fault conditions) that could adversely affect protective devices on the network.

New York

New York has a standardized interconnection requirements and application process for new distributed generators 2 MW or less connected in parallel with utility distribution systems. The document gives the rules for DER interconnection into spot and grid networks. However, it states that synchronous generators shall not be permitted to connect to secondary network systems without the approval of the utility. This allows the utilities to determine under what conditions synchronous generators will be connected to secondary networks. Con Ed, as discussed below, has determined that synchronous generators may not be connected to grid networks at all.

Con Ed

Con Ed's interconnection web page details the requirements for the interconnection of DER into their system. Of particular interest is **Table 4-2**, which outlines the types of interconnections that are permissible.

	Synchronous	Induction	Inverted
Secondary Voltage Non-Network, Radial	Standby Standby / Stand-alone	Standby	Net Metered (PV only) Standby Standby / Stand-alone
Secondary Voltage Grid Network Systems	Not Available	Standby	Net Metered (PV only) Standby Standby / Stand-alone
Spot Network 277/480 or 120/208	Standby Standby / Stand-alone	Standby	Standby Standby / Stand-alone
4KV to 33KV Primary (High Tension) Feeders	Standby Standby / Stand-alone Buy Back	Standby Buy Back	Standby Standby / Stand-alone Buy Back

Table 4-2
Allowable Combinations of Generator Type, Voltage Level, and Service Category for Con-Ed (source: Con-Ed)

Oregon

The regulations in the state of Oregon do not specifically address the interconnection of DER in secondary networks. However, Portland General Electric has included guidelines in their interconnection documents.

Portland General Electric

Portland General Electric requires that a DER installed on a network to interrupt its output before the operation of a network protector for any fault upstream of the network. The requirements are contained in the Portland General Electric document *Interconnection Requirements for Distributed Generation*.

As such, PGE will allow DER to be interconnected into a network as long as its relaying trip time is faster than the network protector's reverse power relay.

Texas

Texas requires the utility to accept interconnection of inverter based DER in secondary network if the DER meets certain maximum sized requirements based on total network load. Other DER technologies must also be allowed to interconnect if they meet maximum size requirements based on customer load and total network load. These requirements do not apply in cases where the utility can demonstrate specific reliability or safety problems with the installation.

Wisconsin

Wisconsin regulations refer to the interconnection of DER into spot (and secondary) networks in their interconnection guidelines. The guidelines require the DER owner to supply relaying or control equipment that is acceptable to the utility. It also mentions that detailed engineering studies may be required, without specifying who is financially responsible for these studies.

Summary of Current Guidelines and Practices

The interconnection of DER in spot networks is allowed by several states and/or electric utilities. In most cases, the DER is limited in size to a percentage of total network load and may be limited in the type of technology used. Often, the use of synchronous generators is prohibited. With the exception of New Jersey and Texas, who specifically allow DER interconnection in grid networks, the interconnection of DER in grid networks is discouraged or forbidden.

5
CONCLUSIONS AND RECOMMENDATIONS

The integration of DER in spot and grid networks is much more challenging than the interconnection of DER in radial distribution systems. Engineering and equipment decisions made decades ago work against easy, and inexpensive, integration in most cases. Spot networks, being much less complicated than grid networks, appear to have fewer technological hurdles to overcome. Most stakeholders agree that limited integration of inverter based DER in spot networks is workable. The integration of synchronous machines, with their capability to supply relatively large amounts of fault current, is more troublesome. PG&E's requirement that a minimum number of network protectors be closed before any DER can operate appears to be a good recommendation and it complies with the IEEE 1547 standard. It is likely that more analysis could go into determining the exact number of protectors that must be closed, but their recommendations are a good starting point.

Grid networks present greater problems. They, by design, serve many more customers. Therefore, any integration of DER could negatively impact many, often high profile, customers. Little detailed work has been done in the area of modeling the impacts of DER to grid networks. This puts engineers at a disadvantage when attempting to set rules for the integration of DER. Most utilities, at this time, simply disallow the interconnection of DER in their grid networks. Until more research is complete, this may be a good position to adopt. One possible workaround is to connect the DER to the medium voltage system using a transformer rather than connecting directly to the grid network. However, if this transformer is connected to a network feeder, it may be subjected to extended outages which a network feeder normally experiences. This may also require advanced metering techniques for the customer to gain the financial benefits of running the DER, but these techniques are well understood and easily implemented with modern revenue meters.

Further Research

Further research is needed primarily in three areas: network protectors, communication/control schemes, and DER influence in grid networks. Testing of existing, and proposed, network protectors could quantify their abilities to cope with distributed energy resources in the network. If DER, particularly synchronous generators, are to be successfully applied to networks, network protectors technology will need to be advanced. It is likely that a network protector can be developed to address most DER interconnection issues. The problem becomes one of economics. A grid network can contain hundreds of protectors, all of which might need to be replaced. Locations that contain grid networks are often the same as those that are most attractive for one type of DER; namely, combined heat and power (CHP).

The advancement of communication and control schemes for both the network and DER devices is also important. Many of the problems created by connecting DER devices to secondary networks could be addressed with more sophisticated communication capabilities and control schemes. The protection philosophies used in protecting secondary networks may need to be reevaluated with the integration of DER in mind. Customers may need to allow some form of automatic control of their DER devices in order to ensure the reliability and safety of the secondary network.

Most of the existing analytical work has been done on spot networks. Detailed modeling and evaluations of a full grid network might show where and how generators might be applied on a grid network. The modeling might also determine the practical limits of DER saturation. A very important question to answer is how much DER, as a percentage of network load, can safely be installed? Is it 10%, 20%, 50%? At this point, no one knows.

Development of Software Tools

EPRI has developed a tool to assess the interconnection of DER in radial distribution systems. This tool is known as the DRIA (Distributed Resources Integration Assistant). The development of a similar tool for the integration of DER in secondary network systems could be very valuable for utilities with spot or grid networks. The development of such a tool for grid networks may prove to be infeasible. Grid networks are much more complicated to model and may always require complicated load flow programs, or transient programs such as EMTP, when evaluating the possibility of the integration of DER.

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