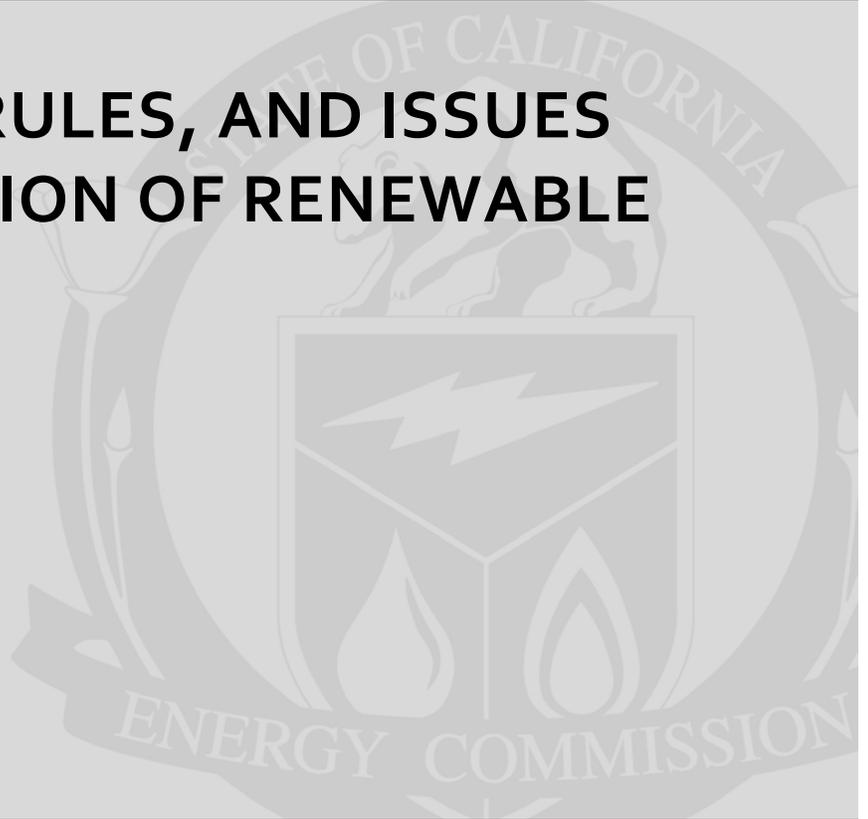


Energy Research and Development Division  
FINAL PROJECT REPORT

**STANDARDS, RULES, AND ISSUES  
FOR INTEGRATION OF RENEWABLE  
RESOURCES**



Prepared for: California Energy Commission  
Prepared by: California Smart Grid Center at Sacramento State

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**PREPARED BY:**

***Primary Author(s):***

Suresh Vadhva  
Mohammad Vaziri  
Chuck Kaufman  
K. Yagnik

Smart Grid Center at Sacramento State  
California State University, Sacramento  
6000 J Street  
Sacramento, CA 95819  
916-278-7944

***Contract Number: BOA-99-231-P***

***Prepared for:***

**California Energy Commission**

Steve Ghadiri  
***Contract Manager***

Fernando Pina  
***Office Manager***  
***Energy Systems Research Office***

Laurie ten Hope  
***Deputy Director***  
***ENERGY RESEARCH AND DEVELOPMENT DIVISION***

Robert P. Oglesby  
***Executive Director***

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## PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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- Renewable Energy Technologies
- Transportation

*Standards, Rules, and Issues for Integration of Renewable Resources* is the final report for the Modeling, The Development of Load Control Strategies and the Integration of Electric Generators Driven by Renewable Resources project (Contract Number BOA-99-231-P) conducted by California State University, Sacramento—School of Engineering. The information from this project contributes to Energy Research and Development Division’s Energy-Related Environmental Research Program.

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## ABSTRACT

This project was composed of three main components or phases. The first phase of the project was discussed in this report. The purpose of the first phase was to gather and document the existing criteria, rules, and practices used by the investor-owned utilities in California for physical interconnection of distributed energy resources. The criteria set by the National Standard IEEE 1547, State of California Public Utilities Commission Rule 21, and the standard practices used by a sample of major investor-owned utilities were presented and compared. Adequacy, practicality, and controversial issues associated with implementation of the presently used rules and criteria were documented and discussed. Suggestions and recommendations for future research and studies to resolve current implementation issues and uniformity of interconnections were presented.

The second phase of this project will support the investigation and verification of specific system protection-related concerns as introduced in this report under Areas of Concern, such as relay desensitization and selection of proper transformer connection types. The concerns will be verified by using system modeling and simulations with industry software.

The third and final phase of this project will utilize the results achieved through Phase two modeling and simulations to develop information needed to proceed with safe interconnection of distributed energy resources through the current standards and rules, while considering the relevant technical issues outlined in this report.

**Keywords:** Interconnection criteria, island, distributed energy resources, distributed resources, Smart Grid, islanding, relay desensitization, transformer replacement

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# EXECUTIVE SUMMARY

## Introduction

California is the most populous state in the United States. Its utilities serve one of the largest residential, commercial, and industrial loads in the country. The summer peak demand for California is approximately 46,000 megawatts (MW) and as much as 25 percent of the state's energy is imported. California's load demand is expected to reach 72,000 MW by 2020. Generation from renewable sources, including distributed energy resources should be developed for a smooth integration with the current power system grid to meet this increasing energy demand, reduce dependence on fossil fuels, and relieve the immediate need for constructing transmission lines in California. The keys to achieving safe, reliable integration of renewable resources into the existing grid are the development of a clear understanding of the standards and rules provided by National Standard IEEE 1547, California Public Utilities Commission Rule 21, and the development of an effective, standardized solution to current interconnection issues and practices associated with investor-owned utilities. Extensive research is needed before the interconnection of distributed energy resources can become a streamlined process.

## Project Purpose

The goal of this project was to gather and document the existing criteria, rules, and practices used by investor-owned utilities in California for physical interconnection of distributed energy resources. One objective of this report were to present and compare criteria set by the National Standard IEEE 1547, California Public Utilities Commission Rule 21, and the standard practices used by a sample of major investor-owned utilities. Another objective was to document and discuss adequacy, practicality, and controversial implementation problems associated with the presently used rules and criteria. The final objective was to provide suggestions and recommendations for future research and studies that will facilitate practical and uniform implementation.

## Project Results

This interim report was the first phase of an investigative analysis addressing the current rules, criteria, and practices of investor-owned utilities for interconnecting distributed energy resources with power systems. The criteria and rules were documented under the categories of Planning/Design, Power Quality, and System Protection/Reliability. This report established and documented the standard rules for interconnection of distributed energy resources and presented them in a single, unified document. Unresolved system issues and concerns arising from distributed energy resources interconnection were presented under Areas of Concern. It was determined that National Standard IEEE 1547 and California Public Utilities Commission Rule 21 contain criteria and rules for interconnection of distributed energy resources that are subject to interpretation by the utilities. Examination of a sample major investor-owned utility (Pacific Gas and Electric) showed that implementation of these rules was more related to the location and the overall system configuration than they were by National Standard IEEE 1547 or California Public Utilities Commission Rule 21. Researchers observed that an entity desiring to interconnect could be better informed as to the most important engineering issues for

interconnection. This observation was discussed under the categories of Planning/Design, System Protection/Reliability, and Power Quality.

Distributed energy resources have the potential to offer great benefits to the electrical power system. However, the electrical distribution system needs to evolve in several important ways for these potential benefits to be fully realized. A comprehensive systems approach to addressing systems integration was needed to fully understand and alleviate the undesirable impacts of distributed energy resources interconnections.

Further development of distributed energy resources integration was being accomplished despite the lack of: (1) universally accepted approaches to systems impacts; (2) comprehensive analyses that account for grid modernization including distributed energy resources; and (3) the prerequisite qualification of modern, standardized interconnection systems. Resolving these deficiencies will establish more effective practices for the development, planning, operating, and maintaining of a modern grid that includes distributed energy resources.

Various sizes of distributed energy resources interconnected to points of a typical distribution feeder should be modeled and investigated. Simulation studies should be performed on the models to verify and document that the technical interconnection concerns have been addressed and to investigate possible solutions.

Further research was recommended based on the review of the presently used criteria and standards for interconnection and the associated modeling and simulations for physical connection of distributed energy resources. Future research should incorporate the proposed roadmap and directions recommended in this report to establish optimized interconnection procedures and rules.

## **Project Benefits**

The integration of distributed energy resources can provide many benefits to California, including:

- Increased system reliability.
- Reduced peak power requirements.
- Power quality improvements.
- Avoiding increased greenhouse gas emissions.
- Reducing transmission line costs/investments.
- Reducing transmission line losses.
- Deferred investments to upgrade existing generation, transmission, and distribution systems.
- Improved efficiency.
- Power supply for critical loads.

This project was an important first step in overcoming some of the current issues related to interconnection of distributed energy resources. The ultimate goal of this work was to alleviate some portion of California's peak energy demand requirement and to provide an

accommodation strategy for future expected peak demand growth through the use of supplemental generation sources.



# CHAPTER 1:

## Introduction

The power industry is currently experiencing a modernization revolution in terms of technologies and strategies being employed to alleviate the growing power demands. Additionally, significant increases in DER interconnections have materialized over the past few decades and many more are requesting approval for interconnection. Environmental concerns and advances in these DER technologies are some of the driving forces behind the push for DER interconnections using clean and renewable resources. Another driving force is the California Renewable Portfolio Standard (RPS) [1], which was created on November 17, 2008. A mandated RPS of 33 percent by 2020 is expected in addition to the 20 percent by 2010 order. Non-conventional generation sources especially wind and solar Photo Voltaic (PV) are some of the renewable resources considered as part of fulfilling the RPS.

Smart Grid (SG) initiatives in California are intended to enable policy-driven objectives such as (1) the integration of up to 33 percent of generation coming from central & local renewable sources; (2) the reduction of Greenhouse Gas (GHG) emissions to below 1990 levels; (3) the creation of zero net-energy facilities by 2020 and 2030. Energy efficiency and demand response policy objectives have already led to California Public Utilities Commission (CPUC) approvals for (1) IOU investments in Advanced Metering Infrastructure (AMI) and (2) opt-out time-differentiated electricity pricing for consumers enabled with AMI meters. In addition, the California Independent System Operator (CAISO) has recently released version 1.0 of its Market Redesign and Technology Upgrade (MRTU), which is intended to be the first step towards statewide Location-based Marginal Pricing (LMP). To inform and support the state's policy objectives, research is required to define, construct and test models (soft and hard) that can improve the interconnection criteria for the integration of DER from renewable resources utilizing the capabilities of the emerging Smart Grids.

One of the biggest issues in California is the constraint on the transmission system. Constructing a new transmission line is a complicated process that requires extensive planning, long lead-time, and significant funding. One possible solution that can help with the objectives of the RPS and mitigate the transmission constraints may be to modify the distribution system design to allow for additional DER interconnections.

The terms Distributed Generation (DG), Distributed Resource (DR), and Distributed Energy Resources (DER), all appear in various technical literature and all three terms refer to small, local electric energy generating units from various resources. A DER has no distinction as to its source of energy, whether combustion turbine or reciprocating engine, wind, photovoltaic, or emerging technology such as energy storage systems. Conventional power plants are much larger and are usually constructed in remote locations where their generated electricity must then be transmitted for comparatively longer distances before reaching the load centers. A significant advantage of a DER is that it can help reduce and postpone the need for construction of new high-voltage transmission lines. Power transmission efficiency will also improve since

power losses through lines will decrease due to the proximity of the distributed resource to the load centers.

Safe and reliable interconnection of DER will prove beneficial to mitigating many of the existing power system issues. Benefits of interconnection of DER include mitigation of transformer overloading, reduction in number of low voltage conditions, and improvements in power quality [12]. In comparison to traditional transmission topology where loads are served at the far end of the transmission network, DER provides specific benefits to the grid and other customers within the service territory. Currently, a variety of methodologies have been proposed to implement the use of DER to reduce peak load requirements and to improve load management. DER also has the potential to be used by system planners and operators to improve system reliability. [16]

Reliability improvements can be realized through implementation of DER by increasing the diversity of the power supply options. Other indirect ways DER can improve reliability are by reducing stress on grid components to the extent that the individual component reliability is enhanced. For example, DER could reduce the number of hours that a substation transformer operates at elevated temperature levels, which would in turn extend the life of that transformer, thus improving the reliability of that component.

Despite the benefits, there are also significant technical and operational concerns that must be addressed to achieve a safe and reliable integration of DER. Significant Planning / Design, Power Quality, and System Protection / Reliability problems arise when a DER is interconnected to the current distribution grids. One reason for these problems is that the distribution system has not been designed for bi-directional power flow and DER will alter power flow in such a way. National Standard IEEE 1547 [2] and California Public Utilities Rule 21 [3] criteria have addressed many of the common problems of interconnection. However, there are still many noteworthy issues in need of future resolution.

National Standard IEEE 1547 and California Public Utilities Commission Rule 21 provide the essential criteria for interconnection of Distributed Generation (DG) to distribution systems. New smart technologies for measuring and controlling bi-directional power flow, voltage regulation, system protection, and quality of power deliveries for the distribution system, need to be designed. These new concepts are being considered in the design of the future electrical supply systems known as the smart grids.

Considerable effort is being made to develop a strategy to modernize the United States grid and transform it into a smart grid. A smart grid is proposed to have the following characteristics: [14]

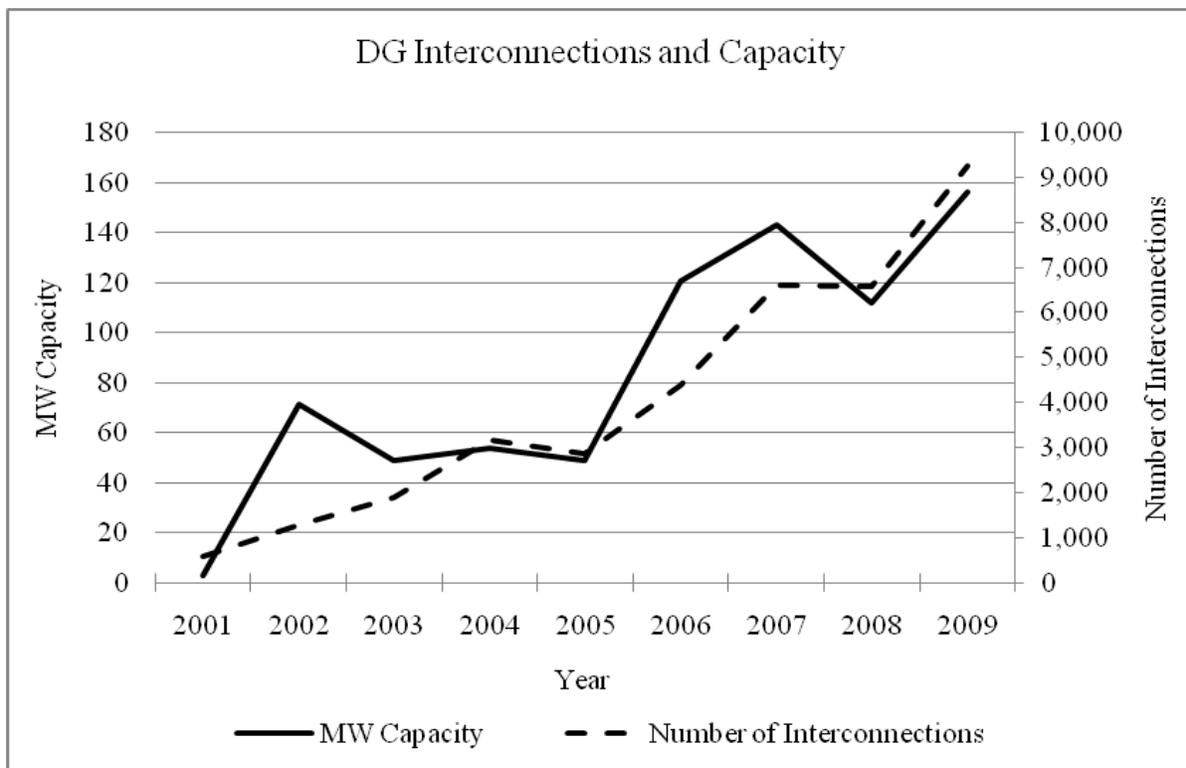
- Allows active participation by consumers in demand response (including distributed generation);
- Operates resiliently against both physical and cyber attacks;
- Maintains high power quality;
- Accommodates all generation and storage options;

- Enables new applications including DER and load participation, self-healing capabilities, and provides an energy efficient operation;
- Incorporates interactive power / load control through state of the art communication technologies.

One of the more significant aspects of the modern grid as currently envisioned is that it seamlessly integrates many types of load, generation, and storage systems with simplified interconnection processes.

Displayed in Figure 1, we can see significant increases in Mega Watt (MW) capacity of DER and the number of DER interconnections for every year.

**Figure 1: DER Growth in California From IOUs**



Source: Provided by author

The chart above shows the numbers of DER interconnections and installed capacity for one of the major IOUs in Northern California, known as the Pacific Gas and Electric Company (PG&E), over last decade. There have been significant increases in the PV and machine based DER in last few years. Recent research is proposing the use of new technologies with energy storage capabilities such as battery and flywheel to increase reliability through DER. For example, systems incorporating a large penetration of wind power generation may elect to supplement with a battery system to account for variability of wind, thereby improving reliability. Thus, there are noticeable incremental increases in MW capacity of DER units every year. The main objectives of this project are as follows:

- Gather, document, and compare the existing rules and criteria used for DER interconnection;
- Investigate and identify major System Protection related issues and concerns associated with the interconnection of DER;
- Verify the findings by computer simulations using a utility grade software;
- Identify and propose areas in need of future research;
- Provide concluding remarks from the investigations and the analyses.

Interconnection criteria will be listed and discussed under the main categories of IEEE Standard 1547, CPUC Rule 21 and a sample IOU. The discussion will focus on three main areas: Planning / Design, System Protection / Reliability, and Power Quality.

The organization of the project chapters is as follows:

- Chapter 1: Introduction
- Chapter 2: Summary of Interconnection Requirements
- Chapter 3: Comparative Discussion of Various Criteria
- Chapter 4: Areas of Concern
- Chapter 5: Identification of Areas of Research
- Chapter 6: Conclusions and Recommendations
- Chapter 7: Benefits to California
- Chapter 8: References
- Chapter 9: Glossary

Commonly used acronyms as defined by the various standards and rules will be provided in Glossary. Appendix A and B include the simulations for relay desensitization and over stressed equipment.

## 1.1 Definitions

Definitions are given to provide explanation of commonly used terms from National Standard IEEE 1547, CPUC Rule 21, and other sources.

### 1.1.1 Definitions from National Standard IEEE 1547:

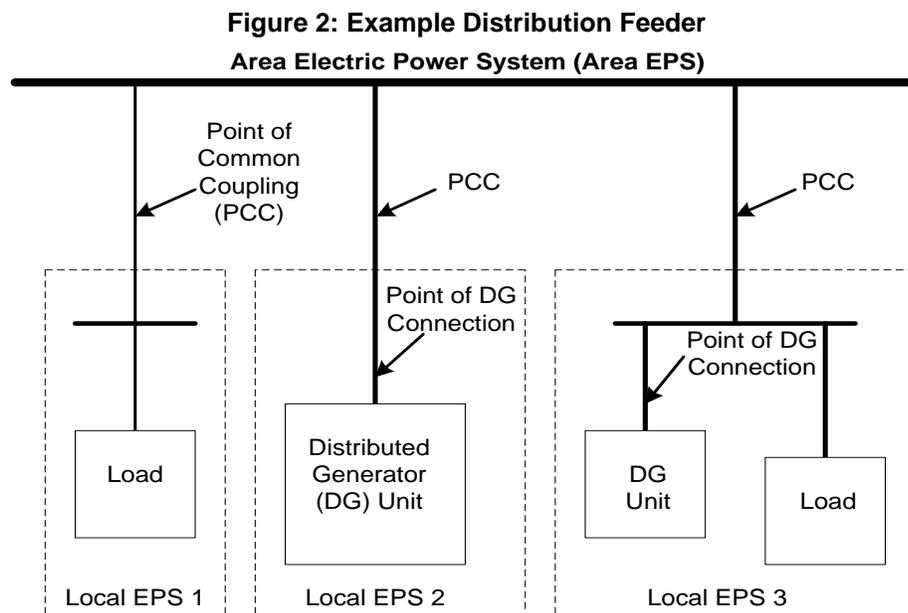
- **Generating Facility (GF):** Electric generation facilities connected to an Area Electric Power System (EPS) through a Point of Common Coupling (PCC); a subset of DER.
- **Distributed Resources (DR):** Sources of electric power that are not directly connected to a bulk power transmission system. DR includes both generators and energy storage technologies.
- **Area Electric Power System Operator (Area EPS Operator):** The entity responsible for designing, building, operating, and maintaining the Area EPS.
- **Inverter:** A machine, device, or system that changes direct-current power to alternating-current power.

- Island: A condition in which a portion of an Area EPS is energized solely by one or more Local EPSs through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS.
- Island, intentional: A planned island.
- Island, unintentional: An unplanned island.
- Non-islanding: Intended to prevent the continued existence of an island.

An example of a section of a distribution feeder with interconnected load and DG has been shown in Figure 2.

### 1.1.2 Definitions from CPUC Rule 21:

- Electric power system (EPS): Facilities that deliver electric power to a load.
- Electric power system, area (Area EPS): An EPS that serves Local EPSs.
- Electric power system, local (Local EPS): An EPS contained entirely within a single premises or group of premises.
- Interconnection: The result of the process of adding a DER unit to an Area EPS.
- Interconnection equipment: Individual or multiple devices used in an interconnection system.
- Interconnection system: The collection of all interconnection equipment and functions, taken as a group, used to interconnect a DER unit(s) to an Area EPS.
- Point of common coupling (PCC): The point where a Local EPS is connected to an Area EPS.



Source: Provided by author

- Point of distributed resources connection (point of DER connection): The point where a DER unit is electrically connected in an EPS
- Cease to energize: Cessation of energy outflow capability
- Simulated utility: An assembly of variable frequency and variable voltage test equipment used to simulate a normal utility source

### 1.1.3 Definitions from PG&E Rule 21

- Interconnection Study: A study to establish the requirements for Interconnection of a Generating Facility with PG&E's Distribution System
- Initial Review: The review by PG&E, following receipt of an Application, to determine the following: (a) the Generating Facility qualifies for Simplified Interconnection; or (b) if the Generating Facility can be made to qualify for Interconnection with a Supplemental Review determining any additional requirements.
- Supplemental Review: A process wherein PG&E further reviews an Application that fails one or more of the Initial Review Process screens. The Supplemental Review may result in one of the following: (a) approval of Interconnection; (b) approval of Interconnection with additional requirements; or (c) cost and schedule for a detailed Interconnection Study.
- Line Section: That portion of PG&E's Distribution System connected to a Customer bounded by automatic sectionalizing devices or the end of the distribution line.
- Secondary Network: A network supplied by several primary feeders suitably interlaced through the area in order to achieve acceptable loading of the transformers under emergency conditions and to provide a system of extremely high service reliability. Secondary networks usually operate at 600 V or lower.
- Simplified Interconnection: Interconnection conforming to the minimum requirements under this Rule, as determined by Section I
- Starting Voltage Drop: The percentage voltage drop at a specified point resulting from In-rush Current. The Starting Voltage Drop can also be expressed in volts on a particular base voltage, (e.g. 6 volts on a 120-volt base, yielding a 5 percent drop).
- Transfer Trip: A Protective Function that trips a Generating Facility remotely by means of an automated communications link controlled by PG&E.

### 1.1.4 Definitions from Other Sources

- DER System Impact: DER interconnection can result in electric grid operating conditions that normally would not occur without the DER installed – these resulting conditions are called as DER system impact.
- Short Circuit Current Ratio (SCCR): The ratio of the short circuit current contribution of the Generating Facility to the short circuit current contribution of the Distribution System at the PCC. [4]
- Null Point: The segments in the distribution network where power flow is zero are called a null point. [18]
- Ferroresonance: A phenomenon characterized by overvoltages and very irregular voltage wave shapes, which are potentially damaging to a transformer, cable, or other equipment. It typically occurs when there is no ground on the system except through the

transformer connected line to ground. It is always associated with the excitation of one or more saturated inductors through capacitance in series with the inductor. When one or two phases are disconnected from the source by single-pole fault clearing or switching, it is possible for the transformer windings connected to the open phases to be excited through the system capacitances to ground and between phases.

- Starting Voltage Drop: The percentage voltage drop at a specified point resulting from In-rush Current. The Starting Voltage Drop can also be expressed in volts on a particular base voltage, (e.g. 6 volts on a 120-volt base, yielding a 5 percent drop).
- Transfer Trip: A Protective Function that trips a Generating Facility remotely by means of an automated communications link controlled by IOU.

## **CHAPTER 2: Summary of Interconnection Requirements**

This chapter provides a summary of interconnection requirements from the current standards for interconnection of DER in California, which includes IEEE 1547, CPUC Rule 21, and a sampled IOU, PG&E.

The integration of DER into the distribution systems often introduces some Design / Planning, System Protection / Reliability, and Power Quality problems. National Standard IEEE 1547 has established criteria and requirements for interconnection of DER with the Area Electric Power System (EPS). The California Public Utility Commission has also established a set of interconnection criteria known as Rule 21 for DER interconnection, which recently adopted most of the interconnection criteria set by the IEEE 1547 standard. The main objective of both documents is to establish a uniform set of criteria, rules, and procedures for interconnections of DER to the power distribution grids. Further, Rule 21 also provides an Initial Review Process (IRP), which can speed the process of DER interconnection. Generation Facilities which do not pass the IRP will be evaluated via a series of steps known collectively as the Supplemental Review process. During a Supplemental Review, further evaluations and studies are performed to determine if there are any specific issues that may be caused by the Generating Facility (GF) interconnection and to determine if there are any mitigating solutions. Utilities have expanded on Rule 21 to create their own varying set of rules and guidelines.

Summarized below are the interconnection criteria for IEEE 1547, CPUC Rule 21, and a sample IOU (PG&E).

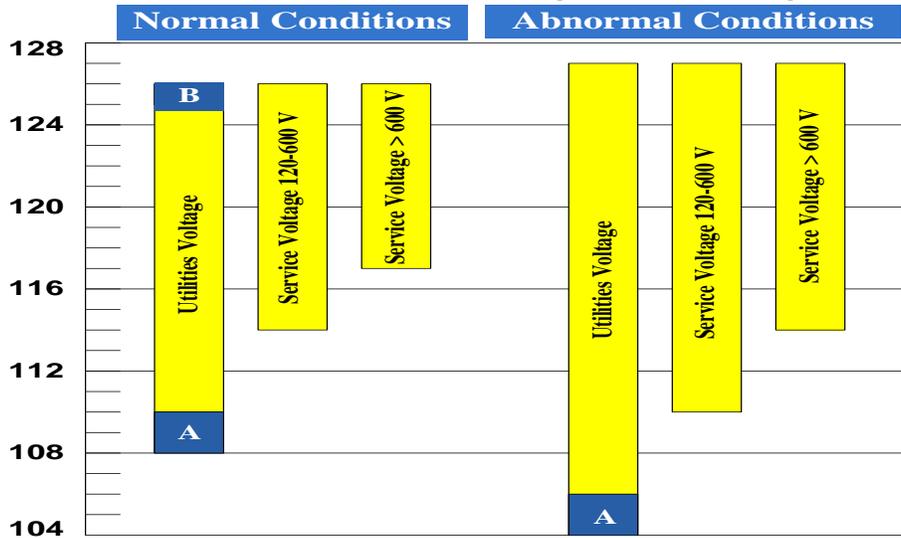
### **2.1 National Standard IEEE 1547:**

IEEE Standard 1547 is the first standard to focus solely on the interconnection of DER for U.S. power systems. It has specified many of the basic rules for interconnection of DER. Considering IEEE Std-1547 as reference, the criteria for DER interconnection in the categories of Planning / Design, System Protection / Reliability, and Power Quality are presented in the following sections.

#### **2.1.1 Planning/Design:**

1. Per IEEE 1547, DER is not allowed to actively regulate the voltage, and the normal operating voltage at the Point of Common Coupling (PCC) will be within Range A of the American National Standard Institute (ANSI) C84.1-1995 [11]. Range A of the referenced ANSI Standard is shown in Table 1.

**Table 1: ANSI Specification Range for PCC Voltage**



Source: Provided by author

2. IEEE 1547- 4.1.3 further specifies that the DER must parallel with the Area EPS without causing a voltage fluctuation at the PCC greater than  $\pm 5$  percent of the prevailing voltage level of the Area EPS.
2. IEEE 1547-4.1.7 design standard requirement states that the isolation device must be a set of disconnect switches that are; accessible, lockable, and provide a visible-break between the Area EPS and the DER.
3. IEEE C37.90.2-1995 specifies that the Interconnection system must have the capability to withstand electromagnetic interference for proper operation of its protective devices.
4. IEEE Std C62.41.2-2002 or IEEE Std C37.90.1-2002. Specifies that the Interconnection system must have the capability to withstand voltage and current surges.

### 2.1.2 System Protection/Reliability:

1. During the condition of inadvertent energization, the DER must not reclose into the Area EPS when the Area EPS is de-energized.
2. The interconnection system paralleling device must withstand 220 percent of system rated voltage.
3. The DER must detect and interrupt connection with the Area EPS for faults on the Area EPS circuit.
4. The DER must not energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS.
5. The DER grounding scheme must not cause overvoltage beyond equipment ratings or disrupt the coordination of the Ground Fault Protection.
6. In the case of an unintentional electrical island, the DER interconnection system must detect the island and separate from the Area EPS connection within two seconds of the formation of an electrical island.

7. Provisions are made for reconnection after an Area EPS disturbance, whereby the DER must not reclose until the Area EPS voltage is within Range B of ANSI C84.1-1995, Table 1, and frequency range of 59.3 Hz to 60.5 Hz.
8. Voltage and Frequency protective functions must be capable of interrupting the DER connection to the Area EPS break within the clearing times specified when the voltage or the frequency at the PCC falls outside of the ranges specified by Tables 2 and 3.
9. Voltages are detected at the PCC when the conditions are as follows:
  - Aggregate capacity of DER Systems at a single PCC is less than or equal to 30 kW,
  - Interconnection equipment is certified to pass a non-islanding test for that system,
  - Aggregate capacity of DER Systems is less than 50 percent of the total Local EPS.

Table 2 shows the specified system response to abnormal voltages and respective clearing times as stated by IEEE 1547.

**Table 2: Interconnection System Response to Abnormal Voltages**

| Voltage range (% of base voltage <sup>a</sup> ) | Clearing time(s) <sup>b</sup> |
|---|-------------------------------|
| V < 50  | 0.16                          |
| 50 ≤ V < 88                                     | 2                             |
| 110 < V < 120                                   | 1                             |
| V ≥ 120   | 0.16                          |

Source: Provided by author

a: Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 3.

b: DER ≤ 30kW, maximum clearing times; DER > 30kW, default clearing times.

Table 3 shows the system response to abnormal frequencies and respective clearing times as stated by IEEE 1547.

**Table 3: Interconnection System Response to Abnormal Frequencies**

| DER size | Frequency range (Hz)                 | Clearing time (s) <sup>a</sup> |
|----------|--------------------------------------|--------------------------------|
| ≤ 30kW   | > 60.5                               | 0.16                           |
|          | > 59.5                               | 0.16                           |
| > 30kW   | > 60.5                               | 0.16                           |
|          | < (59.8-57.0) (adjustable set point) | Adjustable 0.16 to 300         |
|          | < 57.0                               | 0.16                           |

Source: Provided by author

a: DER ≤ 30 kW, maximum clearing times; DER > 30 kW, default clearing times.

Table 4 shows the synchronizing parameter limits for synchronous interconnection as defined by IEEE 1547.

**Table 4: Synchronization Parameter Limits for Synchronous Interconnection**

| Aggregate rating of DER units (kVA) | Frequency difference ( $\Delta f$ , Hz) | Voltage difference ( $\Delta V$ , %) | Phase angle difference ( $\Delta \Phi$ , °) |
|-------------------------------------|---|--------------------------------------|---|
| 0-500                               | 0.3                                     | 10                                   | 20  |
| >500-1500                           | 0.2                                     | 5                                    | 15  |
| >1500-10000                         | 0.1                                     | 3                                    | 10  |

Source: Provided by author

### 2.1.3 Power Quality:

1. Limitation of direct current (DC) injection: The DER and its interconnection system must not inject current more than 0.5 percent of the full rated output current at the point of DER connection DC.
2. Limitation of flicker induced by the DER: The DER must not create out of limit flicker for other customers on the Area EPS.<sup>1</sup>
3. Harmonics: Harmonic current injection into the Area EPS at the PCC shall not exceed the limits stated in Table 5. The harmonic current injections are exclusive of any harmonic currents due to harmonic voltage distortion present in the Area EPS without the DER connected.

Table 5 shows the limits on harmonic current injections into the Area EPS as specified by IEEE 1547.

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1 IEEE 1547-4.3.3

2 Out of limit flicker is flicker that causes a modulation of the light level of lamps sufficient to be disturbing to humans

**Table 5: Maximum Harmonic Current Distortion in Percent of Current (I) (1,2)**

| Individual Harmonic Order h, (Odd Harmonics) | Max Distortion (%) |
|--|--------------------|
| $h < 11$                                     | 4                  |
| $11 \leq h \leq 17$                          | 2                  |
| $17 \leq h \leq 23$                          | 1.5                |
| $23 \leq h \leq 35$                          | 0.6                |
| $35 \leq h$                                  | 0.3                |
| <b>Total demand distortion (TDD)</b>         | <b>5</b>           |

Source: Provided by author

1. I = the greater of the maximum Host Load current average demand over 15 or 30 minutes without the GF, or the GF rated current capacity (transformed to the PCC when a transformer exists between the GF and the PCC).
2. Even harmonics are limited to 25 percent of the odd harmonic limits above.

## **CPUC Rule 21:**

The CPUC Rule 21 has adopted many of the interconnection criteria established by the IEEE 1547. An important addition with Rule 21 is that it provides an Initial Review Process (IRP) where an efficient screening procedure for DER applications expedites the interconnection process. Supplemental Review is provided for applicants not meeting the IRP criteria in which further review is required. The screening process suggested by Rule 21 IRP is shown in Figure 3.

### **2.1.4 Planning/Design:**

1. The DER must not be interconnected to a Secondary Network distribution system. Interconnections to the Secondary Network systems are outside the scope of this rule and will be reviewed on a case-by-case basis.
2. Rule 21 was originally designed for Non-Exporting generating units with sufficient assurance that no export of power takes place across the PCC. The following options are made available to the applicant to ensure a non-export interconnection.
  - i. *Option 1:* Reverse Power protective function at the PCC with default setting of 0.1 percent of transformer rating, and a maximum time delay of 2.0 seconds.
  - ii. *Option 2:* An under-power protective function may be implemented at the PCC where there is a minimum import of power. The default setting value is 5 percent import of the GF Gross Nameplate Rating, with a maximum time delay of 2.0-seconds.
  - iii. *Option 3:* To limit the incidental export of power, all of the following conditions must be met:

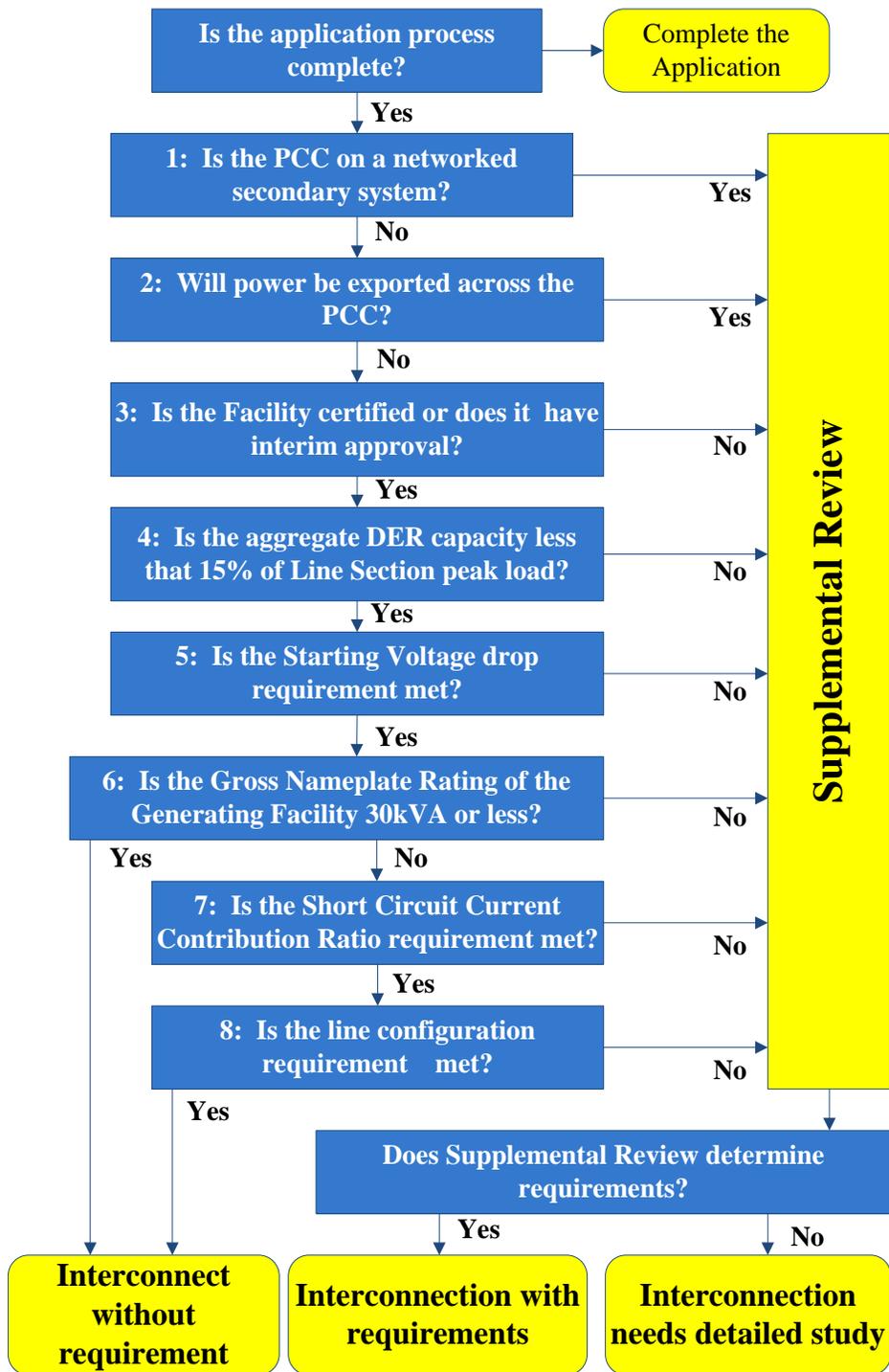
- The aggregate capacity of the GF must be no more than 25 percent of the nominal ampere rating of the customer's service equipment.
  - The total aggregate GF capacity must be no more than 50 percent of the service transformer rating.
  - The GF must be certified as Non-Islanding.
- iv. Option 4:* To ensure that the relative capacity of the GF compared to facility load results in no export of power without the use of additional devices. The GF capacity must be no greater than 50 percent of the customer's verifiable minimum load over the last 12 months.
- Interconnection Equipment must be certified under Rule 21.
  - The aggregate GF capacity on the line section is 15 percent of line section peak load insures the line capacity is below its maximum capacity.
  - The starting voltage drop must be within acceptable limits as determined by the area EPS. This criterion is to ensure that the distribution system will not experience out of limit voltage flickers during start-ups (or tripping) for large generators.
  - The power factor must be between 0.9 leading and 0.9 lagging, although a correction is possible if outside this range.

This IRP and the associated flowchart were developed to expedite the approval process of generating units that meet certain predetermined criteria.

The IRP provides a systematic and consistent process for the utility to follow when reviewing an interconnection application. By providing a series of screening thresholds, the utility can quickly determine whether an interconnection will be a simple one with minimal requirements, or if it requires a supplemental review.

Supplemental review means that additional consideration must be given to interconnection requirements and the need for a possible interconnection study will be examined.

**Figure 3: Initial Review Process Flowchart**



Source: Provided by author

## System Protection/Reliability:

1. Short circuit current contribution requirements are meant to show that the GF has a small enough impact such that it is unnecessary to perform a short circuit contribution analysis.
2. At high voltage side of the Dedicated (or the Interconnection) Distribution Transformer, the sum of the Short Circuit Contribution Ratios (SCCR) of all Generating Facilities on the Distribution System circuit may not exceed 0.1. This is cumulative criterion on a first-come-first-serve basis. Once the cumulative SCCR of 0.1 has been surpassed, additional Fault Detecting schemes must be added at PCC.<sup>2</sup> The schemes are to enable the new interconnecting facility detect and clear for faults occurring on the area EPS system.
3. For customers that are metered at the low voltage (secondary) levels of a shared distribution transformer, the short circuit contribution of the proposed GF must be less than or equal to 2.5 percent of the interrupting rating of the utilities service equipment.
4. The Line Configuration is acceptable for Simplified Interconnection:
  - If the primary distribution circuit serving the GF is of a three-wire type, or if the GF's interconnection (distribution) transformer is single-phase and connected in a line-to-neutral configuration, then there is no concern about over-voltages to the Distribution System or other customer's equipment caused by loss of system neutral grounding during the operating time of anti-islanding protection.
  - If the GF is served by a three-phase four wire service or if the Distribution System connected to the GF is a mixture of three and four wire systems, then aggregate GF capacity that exceeds 10 percent of the Line Section peak load must be reviewed. This screening process is intended to limit over voltages to the Distribution System or customer's equipment caused by loss of system neutral grounding during an Unintentional Island before the operating time of an anti-islanding protection scheme. The 10 percent limit ensures that the local load is much greater than the output of the GF so that the load causes a significant voltage drop and prevents the possibility of overvoltage caused by loss of system neutral grounding.
5. Table 2, from the IEEE 1547 Standard that addresses the system response to abnormal voltages, has been adopted by Rule 21 where clearing time limits are specified.
6. Table 3, from the IEEE 1547 Standard that addresses the system response to abnormal frequencies and the respective clearing times limits, and has been adopted by Rule 21.
7. Table 4. from the IEEE 1547 Standard that has been adopted by Rule 21 and provides the required synchronizing parameter limits.

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<sup>2</sup> Fault Detecting schemes are referred to equipment that detect and interrupt multiphase and ground faults on the utility systems.

### 2.1.5 Power Quality:

Rule 21 has adopted the power quality requirements IEEE Standard-1547.

1. Harmonic distortion limits: GF harmonic distortion must comply with IEEE STD 519-1992. Exceptions shall be evaluated using the same IEEE STD 519-1992 criteria for the loads at host load site.
2. DC injection limits: DC injection must be less than 0.5 percent of GF rated output current. Table 5 specifies the limits on harmonic current injection into the Area EPS, which have been adopted by Rule 21.

Major IOU- PG & E:

PG&E has adopted the CPUC Rule 21 as its DER interconnection criteria. PG&E has two sets of interconnection handbooks: one for Transmission interconnections, which differs from the Rule 21, and the other for distribution interconnections. For DER interconnections, major focus is given to the Distribution Interconnection Handbook.

### 2.1.6 Planning/Design:

PG&E uses the screening thresholds as defined in the Rule-21 IRP screening.

1. Simplified Interconnections:  
Small, certified, non-exporting generators are included in this category.
2. Supplemental Interconnection:
  - i. 15 percent Rule – The applicant’s generating system combined with existing generation does not exceed 15 percent of the maximum loading of the line section.
  - ii. Overloading – PG&E’s equipment and line rating are not overloaded by the applicant’s generating system.
  - iii. Voltage operating levels – In steady state operating conditions, the applicant’s generating system does not create a voltage drop or rise that goes above or below the allowable operating-voltage range. Allowable operating voltage levels have been specified in the CPUC Rule 2, which are the same as the ANSI standards.

### 2.1.7 System Protection/Reliability:

1. The sum of the SCCRs of all GFs on the Distribution System circuit must be less than 0.1.

Table 6 summarizes the protective device schemes for various power levels for PG&E systems. The minimum protection devices are prescribed with respect to the power limits

**Table 6: Protective Device Schemes for Various Power Levels for PG&E Systems**

| Generator – Protection Device  | Device Number <sup>1</sup> | Up to 40 kW    | 41-400 kW      | Above 400 kW   |
|--|----------------------------|----------------|----------------|----------------|
| Phase Overcurrent  | 50/51                      | X <sup>2</sup> | X <sup>2</sup> |                |
| Overvoltage  | 59                         | X              | X              | X              |
| Under-voltage  | 27                         | X <sup>3</sup> | X              | X              |
| Over-frequency   | 81O                        | X              | X              | X              |
| Under-frequency  | 81U                        | X              | X              | X              |
| Ground-Fault-Sensing Scheme  | 51N                        |                | X <sup>4</sup> | X              |
| Overcurrent with Voltage Restraint or Overcurrent with Voltage Control | 51V<br>51C                 |                | X <sup>5</sup> | X              |
| Reverse-Power Relay  | 32                         | X <sup>6</sup> | X <sup>6</sup> | X <sup>6</sup> |
| Direct-Transfer Trip   | TT                         | X <sup>7</sup> | X <sup>7</sup> | X <sup>7</sup> |

Source: Provided by author

**Notes:**

1. Standard device numbers, definitions, and functions are given in PG&E handbook of interconnection.
2. When fault-detection is required, per CPUC Rule 21, the phase overcurrent protection must be able to detect all line-end phase and phase-fault conditions.
3. The generator must be equipped with a phase instantaneous-overcurrent relay that can detect a line fault under subtransient conditions.
4. The generator does not have to be equipped with a phase Instantaneous-overcurrent relay if the generator uses a 51V or 51C relay. PG&E determines if a 51V or a 51C relay is better suited for the specific project.
5. For generators rated at 40 kW or less, installing a contactor undervoltage release may meet the undervoltage protection requirement.
6. If CPUC Rule 21 requires fault protection, then ground-fault detection is required for any noncertified inverter-based, induction, or synchronous generating facility.
7. Synchronous generators with an aggregate generation over 40 kW and induction generators with an aggregate generation over 100 kW require ground-fault detection.

8. When CPUC Rule 21 requires fault protection, a group of generators each less than 400 kW but whose aggregate capacity is 400 kW or greater, must have an overcurrent-relay with voltage restraint (or voltage control, if determined by PG&E) installed on each generator rated greater than 100 kW.
9. For nonexport generating facilities operating under the proper system conditions, and having a finite minimum import (excluding any possibility of an incidental or an inadvertent export), a set of three single-phase, very sensitive reverse-power relays, along with the dedicated transformer, may be used in lieu of ground-fault protection.
10. PG&E prefers that the relay be set as an under-power element. As specified by CPUC Rule 21, the relay can be set at 5 percent of the customer's minimum import power (despite the generator's maximum output) for each phase, to trip the main circuit breaker at a maximum time delay of 2 seconds.
11. As a reverse-power element, the relay must be set for 0.1 percent of the transformer rating with a time delay of 2 seconds, as specified by the CPUC Rule 21.
12. PG&E determines, based on PG&E's circuit configuration and loading, if the distribution-level interconnections require transfer-trip protection<sup>3</sup>.

#### 2.1.8 Power Quality

1. PG&E has adopted the Table 5 power quality requirements as specified by IEEE 1547/Rule 21. In the case that the limits may not be met, a dedicated transformer may be required to reduce the generator harmonics entering the PG&E system.
2. The generating facility must minimize any adverse voltage effects, such as voltage flicker at the point of common coupling (PCC) caused by the facility. The limits must not be exceeded as defined by the Maximum Borderline of Irritation Curve.

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<sup>3</sup> A transfer-trip scheme may be required if PG&E determines that a generation facility cannot detect and trip on PG&E's end-of-line faults within an acceptable time frame, or if PG&E determines that the generation facility is capable of keeping a PG&E line energized with the PG&E source disconnected

## **CHAPTER 3: Comparative Discussion of Various Criteria**

The IEEE 1547 standard establishes criteria and requirements for interconnection of DER with the area EPS. The criteria for interconnection are specified in which the operation, performance, equipment conformance testing, safety considerations, and maintenance of the interconnecting facilities are evaluated. IEEE 1547 voltage requirements are stated as; “to be met at the PCC” between the Local EPS and the Area EPS where an aggregate capacity of 10 MVA or less is specified at the PCC. Rule 21 has intentionally avoided any size limits for the facilities interconnecting to the distribution systems. This makes Rule 21 much more liberal in allowing interconnections of any size to the distribution grids. The existing limitations in the loading area (15 percent loading rule) and protection area (0.1 SCCR rule) sufficiently monitor the system for additional reviews and implementation of additional requirements. Some of the other differences between IEEE 1547 and Rule 21 versus PG&E are:

1. PG&E has addressed the possibility of requiring a dedicated transformer, whereas neither IEEE 1547 nor Rule-21 have any provisions for a dedicated transformer requirement.
2. IEEE-1547 and Rule-21 have specified IEEE-519 as the reference for voltage flicker though IEEE-519 has no defined voltage limits for this purpose. PG&E provides a 6V limit on 120V base.
3. Protection against automatic reclosure for out of phase systems is not specifically addressed in IEEE 1547 or Rule-21. PG&E emphasizes Reclose Blocking Schemes to inhibit automatic reclosing into energized systems, whereas other utilities have different criteria.

In Table7, the interconnection process time line from initial inquiry through implementation is compared for three major areas in the United States.

**Table 7: Comparison of Interconnection Application and Implementation Time Lines**

|                | New York   | California   | Texas   |
|----------------|--|--|---|
| <i>Step 1</i>  | Initial communication  | Submission of application and requirements. Time: 3 business day   | Applicant completes application   |
| <i>Step 2</i>  | Inquiry review to determine nature of project and applicant's information needs. Time :3 business day  | Utility shall acknowledge receipt of application and state whether it is complete. Time: 10 business days.   | Processing application and signing inter-connection agreement. Time: 4 weeks for pre-certified equipment & 6 weeks non-pre-certified.   |
| <i>Step 3</i>  | Application filed. Time: Within 5 business days of receipt of application.   | Completion of initial review for simplified interconnection. Time: 10 days after complete application.   | Tentative Extension of deadlines after pre-interconnection studies. Up to 6 weeks for secondaries   |
| <i>Step 4</i>  | Preliminary review and cost estimate for completing the CESIR (Coordinated Electrical System Interconnection Review). Time: 15 days for DER<2 MW | Notification to the applicant for failure of application in initial review. Applicant pays fee and Utility performs supplemental review. Time: 20 business days. | For necessary substantial capital upgrades– applicant is given estimate of cost and schedule. Upon applicant desires to proceed, contract for upgrade is done. Time: 2 weeks. |
| <i>Step 5</i>  | Applicant commits to completion of CESIR and applicable fees.  | Additional study at applicant's expense for significant modifications deemed necessary.  | Interconnection Agreement   |
| <i>Step 6</i>  | Completion of CESIR. Time: 20 business days. For DER>300kw, time: 60 business days.  | Parties enter into applicable agreement  | Connection, testing and operation.  |
| <i>Step 7</i>  | Construction of utility system modifications.  | Construction, testing  |   |
| <i>Step 8</i>  | Construction Schedule as Step 6.   | Interconnection  |   |
| <i>Step 9</i>  | Facility Testing Time: For less than 15kW -2hrs.   | Settlement of costs.   |   |
| <i>Step 10</i> | Final Acceptance & Cost settlement. Time: 60 days.   | Deadlines may vary "Absent any extraordinary circumstances"  |   |

Source: Provided by author

## **CHAPTER 4:**

### **Areas of Concern**

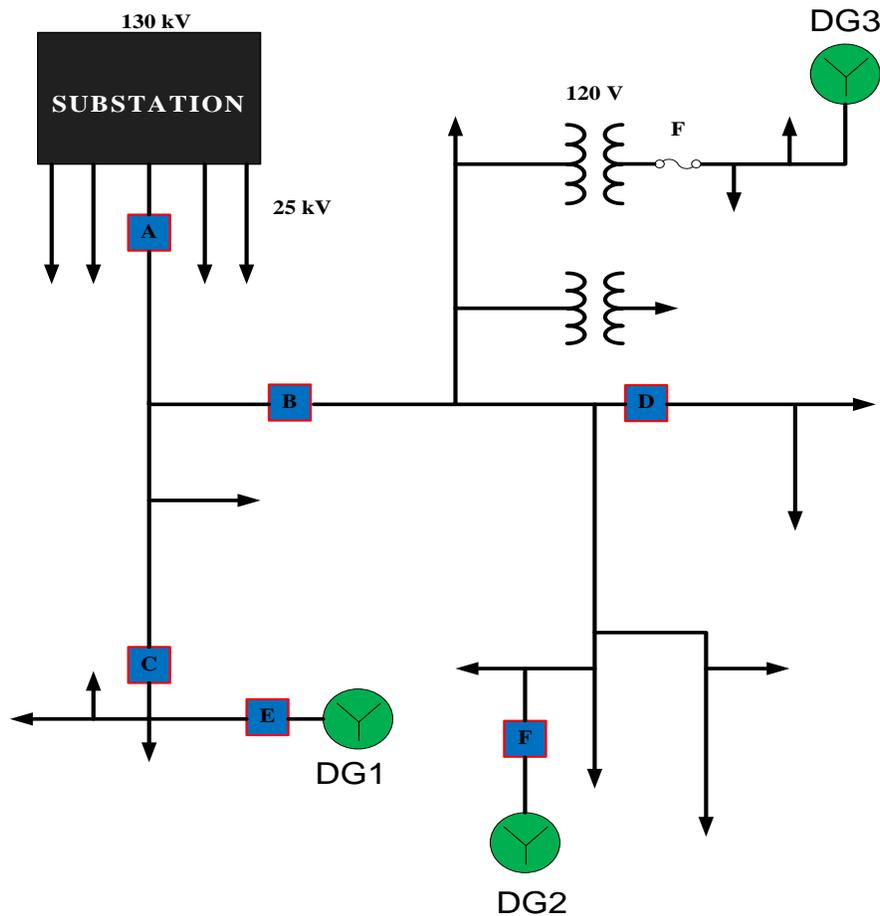
This chapter investigates and identifies major areas of concern related to System Protection that are associated with the interconnection of DER. This includes; unintentional islanding, overstressed equipment, relay desensitization, voltage regulation and flicker, overloaded transformer replacement, and ferresonance.

Connection of the distributed generation with the distribution system causes potential threats to the existing systems. Successful interconnection can be accomplished when these issues are addressed and properly resolved. The prevalent issues are as follows.

#### **4.1 Unintentional Islanding Problems**

Unintentional islanding occurs when a portion of the distribution system becomes electrically isolated from the remaining power system, yet continues to be energized by DER outside of the utility's control. For the network shown in Figure 4, a possible unintentional island can occur when circuit breaker A opens while DER units (DG1, DG2, and DG3) remain in operation keeping the network energized. The most common cause for a circuit breaker to open is a transient ground fault on the feeder which is not detected by the DER units. The melting of a fuse at point F can also result in islanding. In this case, DG3 will supply the local loads, forming a small-islanded power system. An extreme possible scenario is when station circuit breakers B and either of A or C open and fuses, F then melts, creating multiple islanding situations. DG1 will continue to serve local loads up to the breaker point, DG3 will serve local loads up to fuse F and the remaining network will continue to be energized by DG2.

Figure 4: Typical Distribution System with Distributed Generators

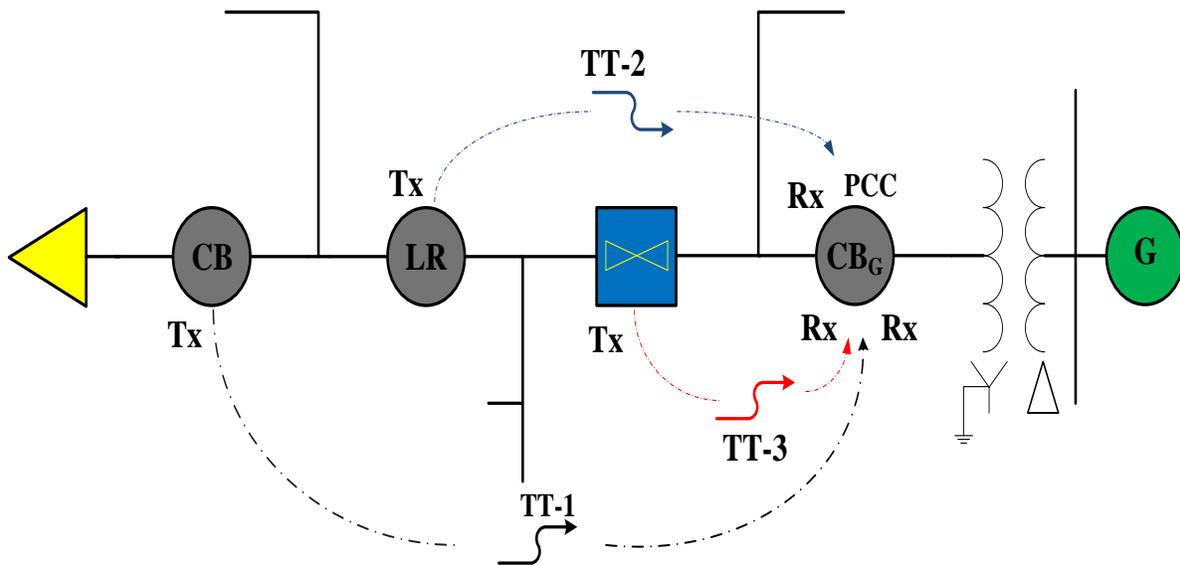


Source: Provided by author

There are several known conditions in which islanded systems can be developed automatically. Transient faults, control failures, and operator errors are among the known conditions. Islanded conditions have also been created by unknown conditions. DER units with stand-alone capabilities such as synchronous generators or voltage source inverter based units can easily form unintentional electrical islands and serve isolated loads. Some crude formulas or rules of thumb have been used as bases in the formation of islands. A widely used criterion is the one that considers an island may be formed when the aggregate size of generating units is equal to or larger than half of the load of the system at the instant of formation of the island. Options to prevent island creation or to cease its continuation include anti-islanding schemes of inverter based units, reverse power relaying schemes, and transfer trip schemes.

Figure 5 shows transfer trip schemes referred to the DER's PCC with the Local EPS.

**Figure 5: Transfer Trip Schemes (TT-1, 2, 3)**



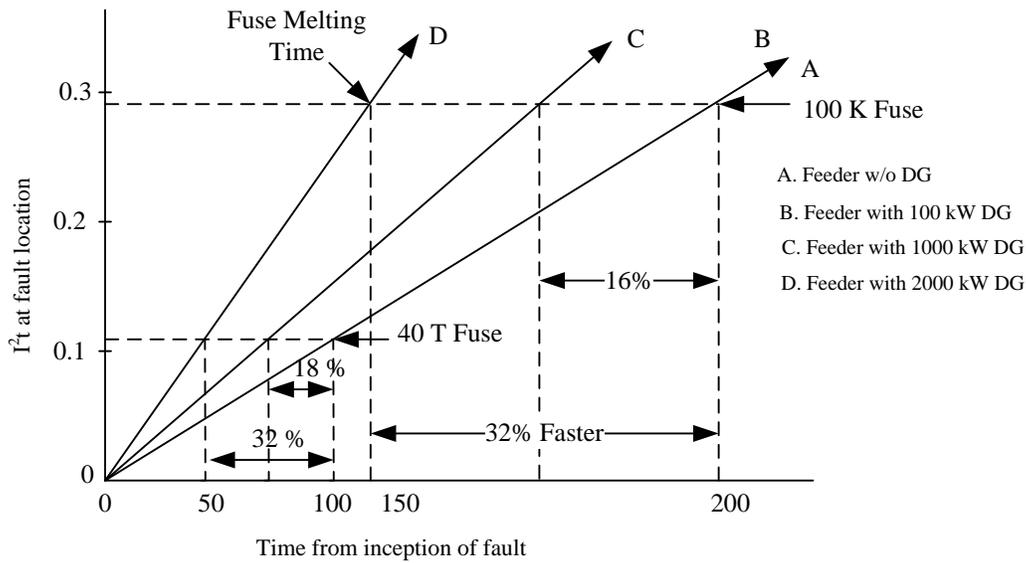
Source: Provided by author

## 4.2 Overstressed Equipment

Addition of generation sources to a distribution system increases short circuit currents at any location on the system. This increases the I<sup>2</sup>t levels for all equipment on the system. I<sup>2</sup>t refers to energy per unit impedance, which tells us about thermal levels as well as the forces due to current carrying conductors that can be expected during a fault with current I being the short-circuited current that flows. An equipment becomes overstressed when the I<sup>2</sup>t value at its location exceeds the withstand capability of the equipment. I<sup>2</sup>t increases and associated impacts will be at maximum in vicinity of the additional unit.

For DER composed of rotating machinery, fault units should be calculated with the lowest unit impedance (i.e.  $X''_d$  for salient pole machines and  $X''_s$  for cylindrical-rotor machines). This will provide a conservative approach. Shown in Figure 5 are the I<sup>2</sup>t increases versus clearing times for 3-phase faults. For single line to ground faults, I<sup>2</sup>t value is calculated similarly. Typical increases in I<sup>2</sup>t values resulting from increases in DER penetration are shown in Figure 6.

**Figure 6: I2t for a 3-Phase Fault on a 12.47 kV Feeder**



Source: Provided by author

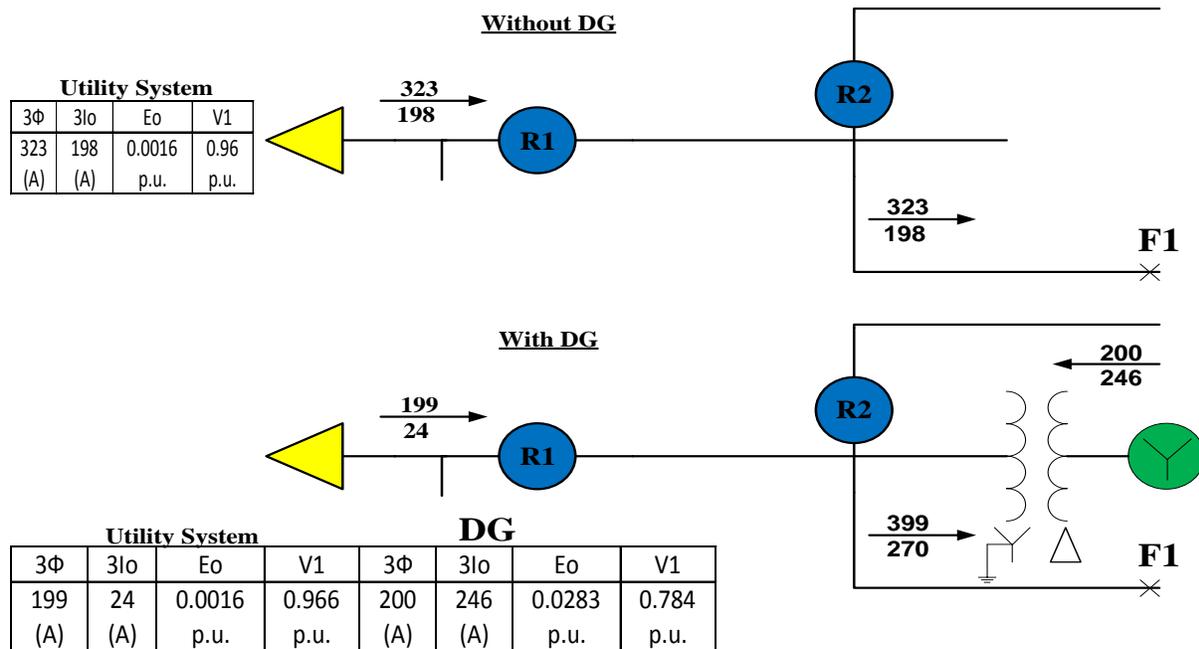
Appendix A provides a detailed analysis of the simulated cases on effects of I2t increases for an actual distribution system.

### 4.3 Relay Desensitization

Integration of generating units increases the total short circuit duty at any point of the system. However, the addition also tends to decrease the contribution from each of the sources. This decrease in contribution from any source is known as Relay Desensitization. For this reason, fault contributions at the end of the protective zones for each protective device between the utility and the DER must be checked to ensure that End of Line (EOL) Protection from each source is maintained. If any protective device is desensitized such that it no longer protects, its zone ends, then additional protective equipment is required.

Figure 7 shows an example of a typical desensitization of protective equipment Reclosure 1 (R1) where a 3-phase fault value of 323 (A) has been reduced to a value of 199 (A) after the addition of DER.

Figure 7: Three Phase and Three Io Currents for Faults at F1



Source: Provided by author

Appendix B provides a detailed analysis of the simulated cases on effects of Relay Desensitization for an actual distribution system.

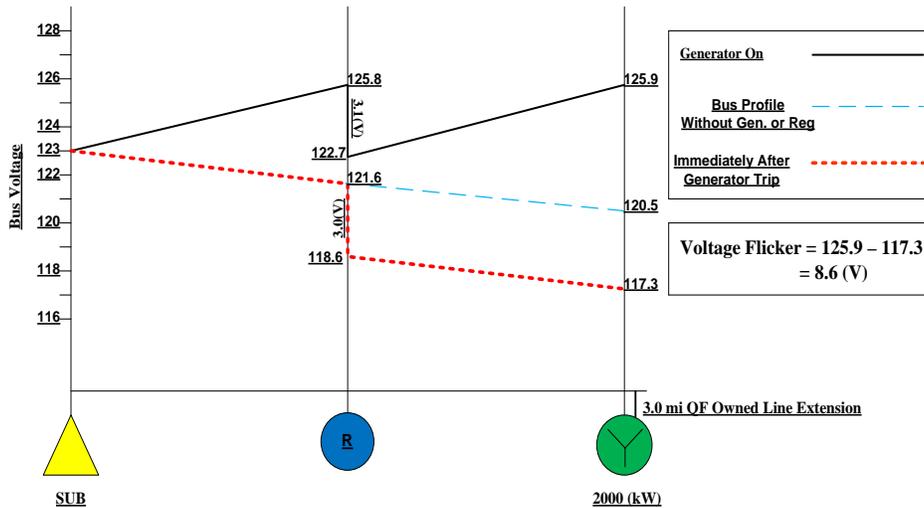
#### 4.4 Voltage Regulation and Flicker Issues

Under normal conditions with a generator on line and back feeding a portion of a utility circuit, the power flows from the utility substation to a null point (segments in which power flow is zero). Power flow in this direction causes voltage drop through the line between the null point and the source station. The reverse direction power flow from the null point towards the generator causes a voltage rise. For instances in which the generator trips off line, the power flow from the null point to the generator location changes direction creating an additional instantaneous voltage drop where it rose before. In the absence of a voltage regulator, this event may cause an unacceptable low voltage condition. Unacceptable voltage fluctuation can occur even when there are regulators available due to their inherent response time limitations. For instance, it is known that voltage regulators take a finite time to readjust to the new load pattern. However, the worst case of total instantaneous voltage flicker is given due to the change from steady state voltage at the generator immediately before and immediately after the unit is disconnected from the system.

Another example of unacceptable voltage flicker is shown in Figure 8. This example shows a maximum voltage flicker for a full load rejection of a DER. The voltage profile is developed from two study cases. The first case is a voltage profile obtained from minimum load and maximum generation. In this case, it is noted that the line regulator is bucking the voltage from

125.8 to 122.7 volts (2.53 percent buck). The second case is a voltage profile with no generation and the regulators blocked at the position of 123 volts for the substation regulator, and the line regulator blocked for the same 2.53 percent as in the first run. The result is a voltage flicker of 8.6 volts that is larger than the acceptable level of 6 volts.

**Figure 8: Minimum Load Voltage Profile**



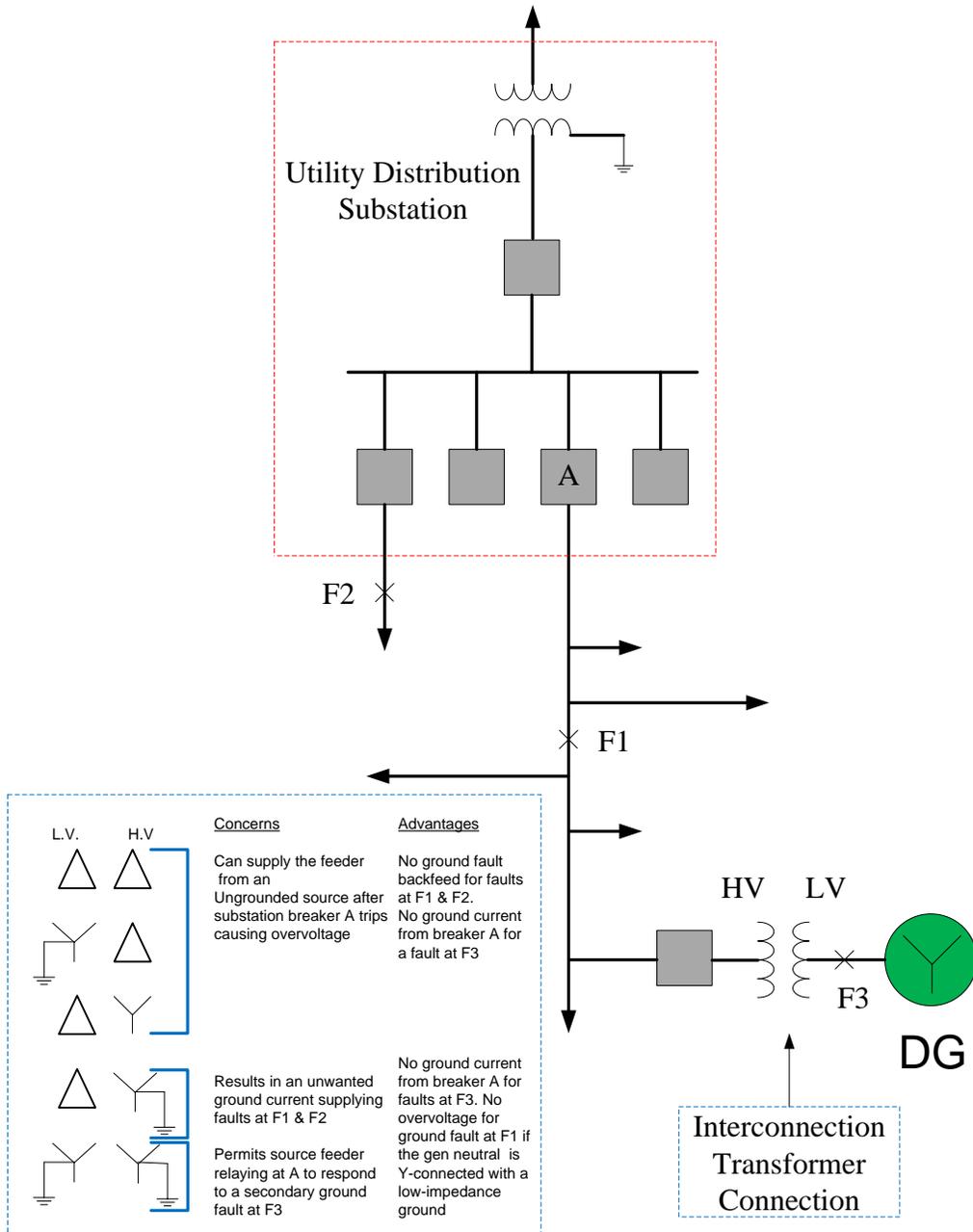
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## 4.5 Transformer Replacement and Interconnection

Transformer replacement is a substantial issue for the interconnection of the DER where additional generation can cause an overload on the service transformer. The criteria used for replacement of overloaded transformer are different among the major utilities in California. CPUC Rule 21 states that a transformer must be replaced when the aggregate size of DER exceeds the nameplate rating of the transformer. However, PG&E allows overloading of the distribution transformers to over 140 percent of their nameplate ratings [15]. It has been suggested that the same criterion should be used for transformer replacement whether the overload is caused by DER integration or by actual increases in loading. This issue is currently under investigation by the Rule 21 technical committee.

Another area of concern regarding the selection of an interconnection transformer is that there is no universally accepted/preferred (Delta, Wye, etc.) connection for the windings. The choice of the winding connections for the interconnection transformer has a major impact on how the distributed generator will interact with the utility system. Figure 9 shows five commonly used connections. Each of these connections has advantages and disadvantages to the utility where protection and coordination of the protective devices are affected.

**Figure 9: Types of Transformer Interconnections**



Source: Provided by author

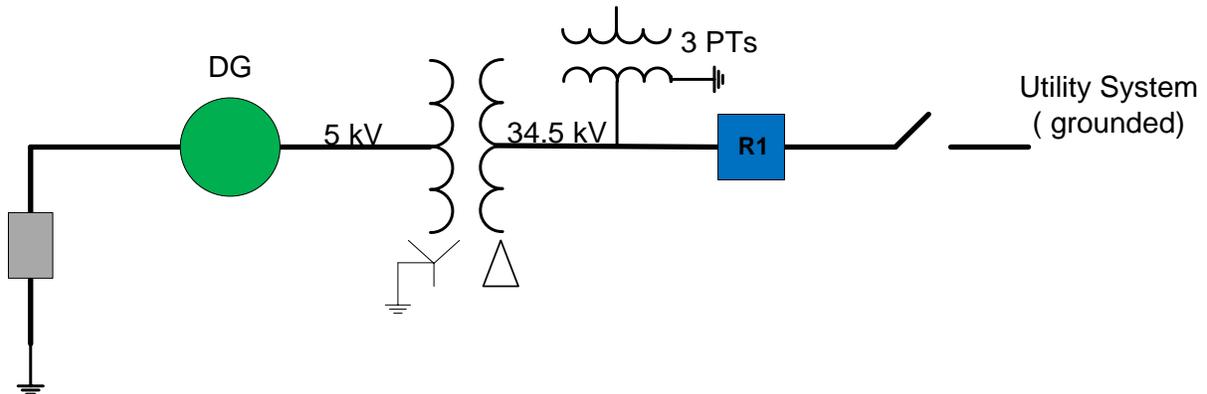
## 4.6 Ferroresonance

During islanding conditions, ferroresonance can occur with DER acting as the driving source in the circuit. The ferroresonance effects can result in significant overvoltages where peak voltage can reach 3 to 4 per unit. [6] Such conditions can occur with both induction and synchronous generators, and can occur with all three phases connected. Ferroresonance condition is likely to happen in the DER islanding when the following four conditions are satisfied:

1. The generator must be operating in an islanded state.
2. The generator must be capable of supplying the island load.
3. Sufficient capacitance must be available on the island to resonate (typically 30-400 percent of the generator rating).
4. A transformer must be present on the island to serve as the non-linear reactance. [10]

A typical power system configuration giving rise to ferroresonance is shown in Figure 10. In this case, a grounded voltage transformer is connected to a system with isolated neutral. A set of voltage transformers with grounded Wye primary windings is connected to a 34.5 kV system that could become ungrounded. One side of the circuit is supplied from the generator and other from the utility. The grounded Wye to Delta generator step up transformer provides no ground reference to the 34.5 kV systems. Opening of the reclosure R1 isolates the DER from the grounded utility source creating an island, which will make the 34.5 kV section of the line ungrounded. During this condition, occurrence of ferroresonance is highly probable.

**Figure 10: Typical Power System configuration Favorable to Ferroresonance**



Source: Provided by author

## CHAPTER 5:

# Identification of Areas in Need of Future Research

There are many unresolved issues with the interconnection of the DER. Some of these have been presented in the earlier chapter Areas of Concern. One of the challenges to DER interconnection is that the electric grid was not designed to accommodate generation at the distribution level. The addition of DER involves two-way distribution of power flows where a DER could send power back into the distribution system thereby causing relay desensitization, unacceptable voltage or flicker conditions, unintentional islanding, or undesirable ferroresonance conditions. Existing grids will need to be evaluated through system impact studies to determine whether they should be remodeled or they are suitable to accommodate DER interconnection. Development of new feeder design criteria based on engineering analyses will be required to establish methods and procedures for reliable interconnection of DG. The new criteria must address applicability, system impacts, and mitigation of known issues for accommodating the increasing use of distributed resources. The advanced utility distribution system of the future known as the smart grid should be capable of extracting the full benefits offered by DER for both the DER owner and for other customers of the distribution system.

Inductive and capacitive components connected at the distribution level promote issues with voltage regulation, voltage flicker, and ferroresonance where a more complex analysis is required. These issues require proper modeling, simulation, and research for steady state as well as transient conditions to determine safe and reliable interconnection techniques.

Although creation of national standards such as the IEEE 1547 has made significant improvements in acceptability and uniformity of DER interconnections, further research and development in this area seems necessary. Further revision of interconnection criteria, identification of smart grid attributes, and formation design criteria for grids of the future are among the areas in need of further studies and research. Future distribution systems need to have the following key capabilities to be able to take the full advantages of the DER benefits in a Smart Grid environment;

- Enhanced technology features;
- System impact studies where modeling, simulation, and real-time comparative analyses and operations;
- A layered control system that satisfies the needs of the customers and loads, the local distribution system, and the transmission grid;
- A well-defined hierarchy of priorities in the control logic;
- A protection system that will accommodate routine two-way power flow with localized generation/storage;

## CHAPTER 6: Conclusions and Recommendations

This chapter presents concluding remarks and recommendations summarizing the DER interconnection rules and standards, system protection related concerns, computer simulations, and future developments.

### 6.1 Conclusions

This project researched and documented the existing rules and criteria for interconnection of DER in one document. Unresolved system issues and concerns due to DER interconnection were presented under Major Areas of Concern. It has been shown that the current rules and the existing criteria set by IEEE 1547 Standard and the CPUC Rule 21 for interconnection of DER are subject to interpretation by the utilities. These documents also fail to address some major areas of concern experienced by the IOUs. This is the main reason that the major IOUs such as PG&E resort to more detailed guidelines and implementation practices specific to each application and type of DER. Documentation of the existing criteria, rules, and issues categorized under Planning/Design, System Protection/Reliability, and Power Quality, will be beneficial to entities seeking DER interconnections to distribution grids of the IOUs.

System Protection related concerns were introduced in this report under Major Areas of Concern. Prevalent technical concerns due to interconnection of DER such as; islanding problems, relay desensitization, overstressed equipment, voltage regulation and flicker issues, transformer replacement and interconnection issues and ferroresonance have been addressed and described with examples. Significant issues of relay desensitization and overstressed equipment were selected from the System Protection related issues for extensive modeling and computer simulations. The results from these simulations validated the concerns and issues raised by this IOU.

Verification of the effects of relay desensitization was provided through simulations. These simulations showed that successive increases in the DER capacity would result in relay desensitization of the station relay. That is, with each incremental increase in DER capacity, the resulting current contribution from the substation was decreased. This verified effect shows the potential that the station relays may be unable to detect the fault current for faults at extremities of the feeder when DER penetration exceeds a certain limit.

The effects of I2t provide insight as to what extent the equipment is experiencing stress whether thermal or mechanical. The rapid increase of fault current per increased capacity of the DER is shown in the simulations. The increase in the DER capacity is inversely proportional to the station current contribution for the fault though overall I2t results show significant increases. These results validate the concern about the added stress levels for the equipment on the distribution network as the DER penetration increases.

Further research is be needed to model and verify other concerns that have been addressed here such as; unintentional islanding, voltage regulation and flicker issues, ferroresonance, power quality, and overloaded transformer replacement.

Although extensive research is needed before the interconnection of DER becomes a streamlined process, this project is a step in the direction of circumventing some of the current issues related to DER interconnections.

## **6.2 Recommendations**

In order to prepare the future electric power system to be smarter, with better load management and more DER interconnections, well-established criteria for Planning/Design, System Protection/Reliability, and Power Quality must be developed for the electric distribution system. When properly interconnected, DERs can provide great benefits to the distribution system. However, the system needs to evolve in several important ways. A complete systems approach that addresses systems integration must be considered in order to fully understand and resolve the undesirable impacts of DER interconnections with technically sound solutions.

Further development of DER integration is still being accomplished despite lack of: (1) universally accepted approaches to systems impacts; (2) comprehensive analyses to account for grid modernization with Distributed Generation; and (3) the prerequisite qualification of modern interconnection systems. Satisfying these deficiencies will establish development of more effective, planning, building, operating, and maintaining of the modern grid, which includes DER.

## CHAPTER 7: Benefits to California

As a general rule, review of existing standards, rules, and processes of DER interconnection and identification of areas of concern is crucial in further implementation of DER on California’s power grid. Despite the areas of concern discussed in Chapter 4, DER has the potential to serve the California power grid in many beneficial ways. Major benefits associated with interconnection of the DER are discussed in this chapter. DER can provide benefits such as enhanced reliability, reduced peak power demand, and improved power quality. Implementing DER can also be beneficial in the mitigation of conditions such as; system instability, voltage regulation, and provision of ancillary services. In comparison to traditional transmission topology where loads are served at the far end of the transmission network, DER can help minimize system power losses. IEEE-1547 and CPUC Rule 21 provide some foundation for uniform interconnection of the DER to the distribution grids.

Some of the benefits from ancillary services that can be provided by DER are shown in Table 8. The first column lists specific services DER is capable of providing. The potential benefits derived from those services can be categorized in one or more of the columns on the right-hand side of the chart. For example, new capacity investments may be deferred by reducing peak power requirements on the grid, or by the provision of ancillary services. Distributed generation available as an emergency supply of power can also be used in demand response programs to reduce congestion, or increase system reliability via peak-sharing.

**Table 8: Matrix of Distributed Generation Benefits and Services**

|                                      | Energy cost savings | Savings in T & D* Losses | Deferred generation Capacity | Deferred T & D capacity | System reliability | Power Quality |
|--------------------------------------|---------------------|--------------------------|------------------------------|-------------------------|--------------------|---------------|
| Reduction in Peak power requirements | X                   | X                        | X                            | X                       | X                  | X             |
| Provision of Ancillary Services      | X                   | X                        | X                            | X                       | X                  | X             |
| Emergency Power Supply               | X                   | X                        |                              |                         | X                  | X             |

Source: Provided by author

\*T&D= Transmission and Distribution

Some of the specific benefits anticipated from the implementation of DER are discussed in the following sections.

## **7.1 Increased Reliability**

Utilization of DER as a Back Up or Stand By sources of energy has been known for some time. Entities in need of reliable sources of energy such as hospitals, police stations, waste water plants, and process sensitive manufacturing plants, have been successfully using DER in this mode. In the Stand By mode, DER is primarily used as a customer-side energy resource for services such as emergency power and uninterruptible power. DER also has the potential to be used as an integrated source in an electrically parallel operation by system planners and operators to improve grid reliability on a larger scale.

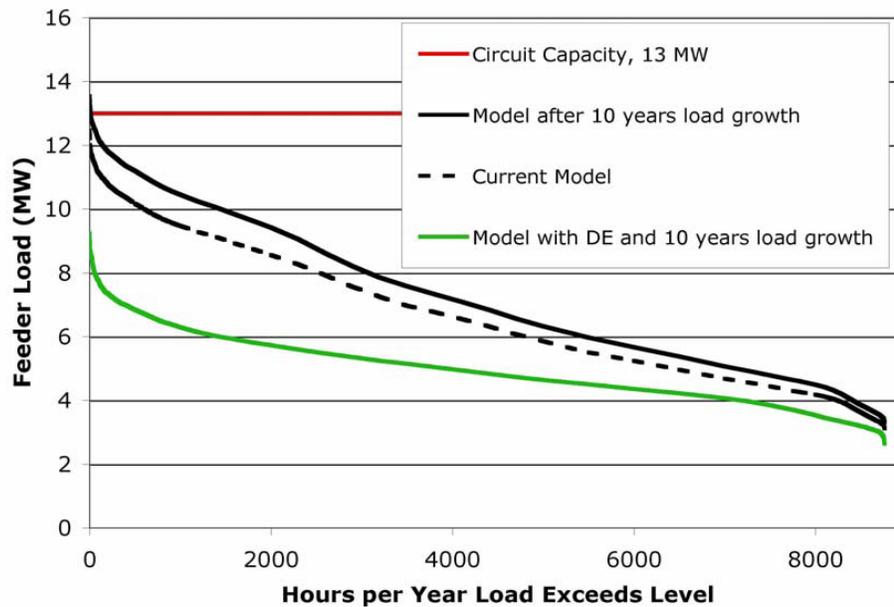
DER can improve reliability by increasing the diversity of the power supply options. DER can improve reliability in indirect ways by reducing stress on grid components to the extent that the individual component reliability is enhanced. For example, DER could reduce the number of hours that a substation transformer operates at elevated temperature levels, which would in turn extend the life of that transformer, thus improving the reliability of that component.

## **7.2 Reduction in Peak Power Requirements**

Several methodologies have been used to implement the use of DER to reduce peak load requirements. In some evaluations, it can be shown that DER is the most financially attractive option; whereas in others, DER may not be the most desirable the choice.

A study from the U.S. Department of Energy (DOE) which focused on two real Southern California Edison (SCE) circuits is presented below. The study shows that adding DER would reduce peak demand on the two circuits enough to defer the need to upgrade circuit capacity. Figure 11 shows the results for the circuit that served a mix of commercial, small industrial and residential customers. If the DER installations are targeted optimally, the deferral could economically benefit SCE and its customers with cost savings that outweigh the lost revenues due to lower sales of electricity.

Figure 11: Comparison of Projected Load on a Feeder With and Without the Addition of DER



Source: Provided by author

### 7.3 Improvement in Power Quality

Power quality problems tend to be localized phenomena and are not often system wide concerns. The increasing use of electronic components and equipment in homes, offices, and factories has increased concerns about power quality and potential damages to equipment and business operations. In certain instances, DER can be used to address power quality problems in localized areas; particularly if the power quality problem is related to incoming voltage. It can be easily shown that the distribution system is weaker at locations farther away from the substation. A higher level of DER installed at the extremities of the distribution system can help reduce the issues with low voltage and unacceptable voltage flicker conditions.

## GLOSSARY

|           |  |
|-----------|--|
| AMI       | Advanced Metering Infrastructure                     |
| ANSI      | American National Standard Institute (ANSI)          |
| Area EPS  | Area Electric Power System                           |
| CAISO     | California Independent System Operator               |
| CEC       | California Energy Commission                         |
| CESIR     | Coordinated Electrical System Interconnection review |
| CPUC      | California Public Utilities Commission               |
| DC        | Direct Current                                       |
| DG        | Distributed Generation                               |
| DER       | Distributed Energy Resources                         |
| DOE       | U.S. Department of Energy                            |
| DR        | Distributed Resources                                |
| EOL       | End of Line  |
| EPS       | Electric Power System                                |
| GF        | Generating Facility                                  |
| GHG       | Greenhouse Gases                                     |
| IEEE      | Institute of Electrical and Electronics Engineering  |
| IOU       | Investor-Owned Utility                               |
| LMP       | Location-based Marginal Pricing                      |
| Local EPS | Local Electric Power System                          |
| MRTU      | Market Redesign and Technology Upgrade               |
| MW        | Megawatts  |
| NREL      | National Renewable Energy Laboratory                 |
| NRTL      | Nationally Recognized Testing Laboratory             |
| PCC       | Point of Common Coupling                             |
| PG & E    | Pacific Gas and Electric Company                     |
| PV        | Photovoltaic   |
| R.P.S.    | Renewable Portfolio Standard                         |
| SCCR      | Short Circuit Contribution Ratio                     |
| SCE       | Southern California Edison                           |
| SDG & E   | San Diego Gas & Electric                             |

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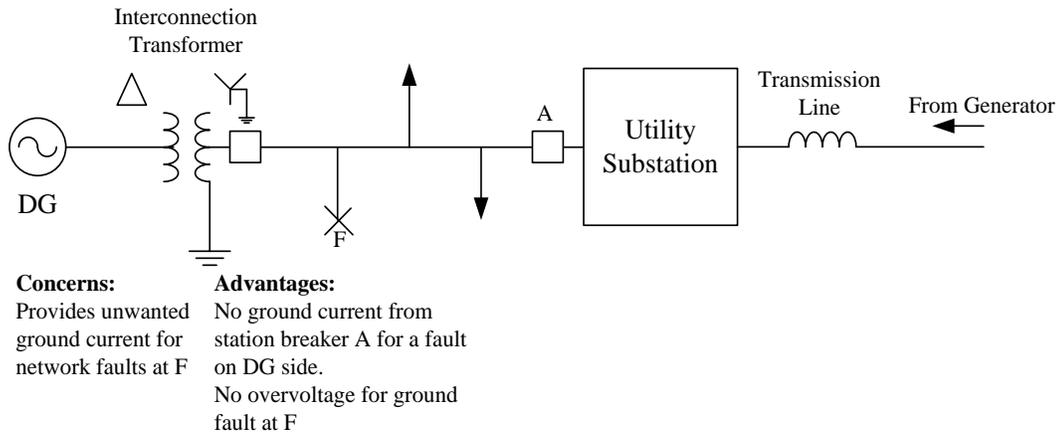
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## APPENDIX A: Overstressed Equipment

It is well known that with addition of generating units to any system, the deliverability of fault currents increases for that system. Hence, the increase in  $I^2t$  value at each location of the system is inevitable. Simulations using the same short circuit software demonstrate the effect of  $I^2t$  increases with respect to increases in the DER capacity. A typical distribution feeder has a radial configuration. A radial configuration refers to a feeder with a single source of supply (the substation) and without any closed loops. In such configuration, the flow of power is unidirectional from the substation towards the loads. Interconnection of DER to a radial distribution feeder reduces the loading on the substation by supplying some of the power needed by the consumers.

In the simulated system, the DER is connected at far end of the network. Figure 12 shows the simplified network topology. Depending on the size of the DER units and the associated interconnection transformer, the current contribution from DER to any fault, such as the one at location F shown by the figure varies in direct relation with the size of DER.

**Figure 5: Transformer Configuration for Overstressed Equipment**



Source: Provided by author

A three-phase fault is simulated at location F by varying the KVA ratings of the DER to see the change in short-circuit current at the fault point that includes contribution of the DER and the station. For continuity, the interconnection transformer is oversized to 10.5 MVA and maintained. In order to find the relay operating time, the short circuit currents are related to the relay time characteristics curves. The fault clearing time values for the protective devices were taken from typical time versus current characteristic curves that had been used for both the substation feeder breaker as well as the DER circuit breaker. The values obtained for current and the clearing times were used for calculations of the  $I^2t$  values.

## Results and Analysis

Multiple simulations were used to verify the results. Increasing the KVA rating of the DER showed increases in the total short circuit currents. As discussed above, the current contribution from the source substation decreases as the DER capacity is increased. With the decrease in the fault value, longer time is taken to clear the fault from the substation, while the total fault value is increased. Therefore, the total I2t values at all fault locations on the feeder are conceivably increased. This has also been verified by the calculated values suggested by Table 9.

**Table 9. Simulation Results for I2t**

| Generator               | EOL                 | Substation |            | DER     |            |
|-------------------------|---------------------|------------|------------|---------|------------|
| KVA                     | Total Fault Current | Current    | Relay Time | Current | Relay Time |
| <i>No DER Connected</i> | 1809                | 1809       | 2          | 0       | 0          |
| 2000                    | 2119                | 1778       | 2.1        | 352     | 2.3        |
| 4000                    | 2387                | 1750       | 2.2        | 656     | 2.6        |
| 6000                    | 2621                | 1724       | 2.4        | 920     | 3.2        |
| 8000                    | 2826                | 1699       | 2.6        | 1151    | 4.4        |
| 10000                   | 3006                | 1677       | 2.9        | 1354    | 6          |

Source: Provided by author

The values of current and time, as well as the actual values of I2t are calculated for the DER contribution and substation contribution for total I2t for each fault. Given below is the sample calculation for the first reading.

$$I^2t_{(DER)} = 352^2 \times 2.3 = 2.8 \times 10^5$$

$$I^2t_{(Station)} = 1778^2 \times 2.1 = 6.6 \times 10^6$$

The individual I2t contributions from the station and DER are added to find the total I2t values. Table 10 displays individual I2t contributions.

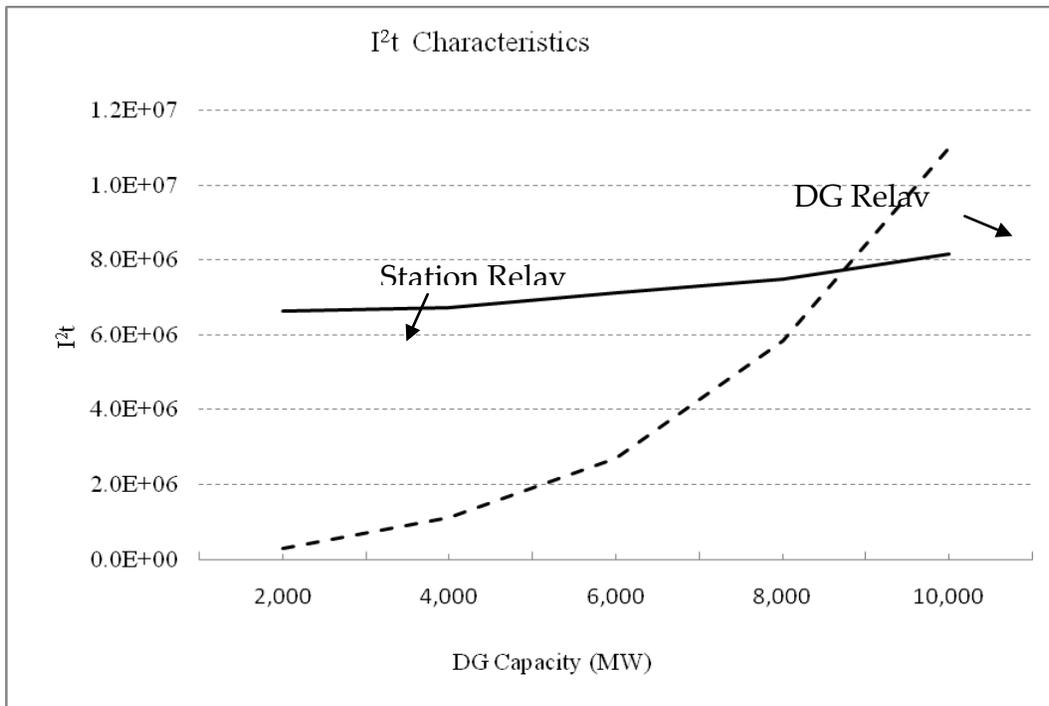
**Table 10. I2t Computations**

| Generator | I <sup>2</sup> t station | I <sup>2</sup> t DER | Total I <sup>2</sup> t |
|-----------|--------------------------|----------------------|------------------------|
| No DER    | 6.5X10 <sup>6</sup>      | 0                    | 6.5 X10 <sup>6</sup>   |
| 2000      | 6.6X10 <sup>6</sup>      | 2.8 X10 <sup>5</sup> | 6.9 X10 <sup>6</sup>   |
| 4000      | 6.7 X10 <sup>6</sup>     | 1.1 X10 <sup>6</sup> | 7.8 X10 <sup>6</sup>   |
| 6000      | 7.1 X10 <sup>6</sup>     | 2.7 X10 <sup>6</sup> | 9.8 X10 <sup>6</sup>   |
| 8000      | 7.5 X10 <sup>6</sup>     | 5.8 X10 <sup>6</sup> | 1.3 X10 <sup>7</sup>   |
| 10000     | 8.1 X10 <sup>6</sup>     | 1.1 X10 <sup>7</sup> | 1.9 X10 <sup>7</sup>   |

Source: Provided by author

The DER relay experiences a steady rate of increase in current while the contribution from the station decreases with each increase in DER capacity. Therefore, the rate of changes the I2t levels contributed by the DER is much steeper than what is contributed by the station. The graphs in Figure 13 show the I2t variations contributed by each source as a function of increasing total DER capacity.

**Figure 6. Characteristics for DER and Station Contributions**



Source: Provided by author

## Appendix B: Relay Desensitization

As shown in Appendix A, the fault current contributions from the utility substation decrease for any fault as the size of DER increases. Therefore, the relay desensitization effects increase as the total capacity of the DER interconnected to a feeder increases. Simulations using short circuit software commonly used by the major utilities validate the results. The interconnection of DER increases the total fault current for any point on the feeder. However, it also tends to decrease the fault current contributions from the source station as well as other DER sources. In the simulated system, a variable size DER is connected at the far end of the network. The connection of the main transformer for the DER is in Delta configuration on the High Voltage (HV) side and in grounded Wye on the Low Voltage (LV) side. This transformer configuration prevents flow of zero sequence currents for faults on the HV side. Therefore, an additional ground fault sensing transformer will be required for zero sequence current fault detection with such transformer connection. In this simulation, ground faults were not considered. The focus of these simulations was 3 phase faults. [7]

Figure 12 in Appendix A, shows the simplified network topology. The main concern is to show the changes in current contributions from each source for the simulated faults. The simulation results are shown for a fault at location F.

A three-phase fault is simulated at location F by varying the KVA ratings of the DER in order to see the change in short-circuit current contributions from DER and the station. The ratings of the interconnection transformer are increased after the load surpasses 120 percent of the nameplate capacity. Table 4 compares the amount of relay desensitization (by decreases in fault current contribution from the substation), the total short circuit current, and the actual contribution of the substation and the DER are compared with increments in the size of the DER.

### Results and Analysis

Simulations are used to verify that successive increases in the DER KVA ratings will result in relay desensitization (decreases in fault current contribution) from the source substation. During simulations, the resulting current contributions from the substation were decreased with successive increments in the DER KVA rating. This verified effect shows that, at some point, the station relays may be unable to detect the fault current for faults at extremities of the feeder.

Table 11 shows the detailed results of the simulations.

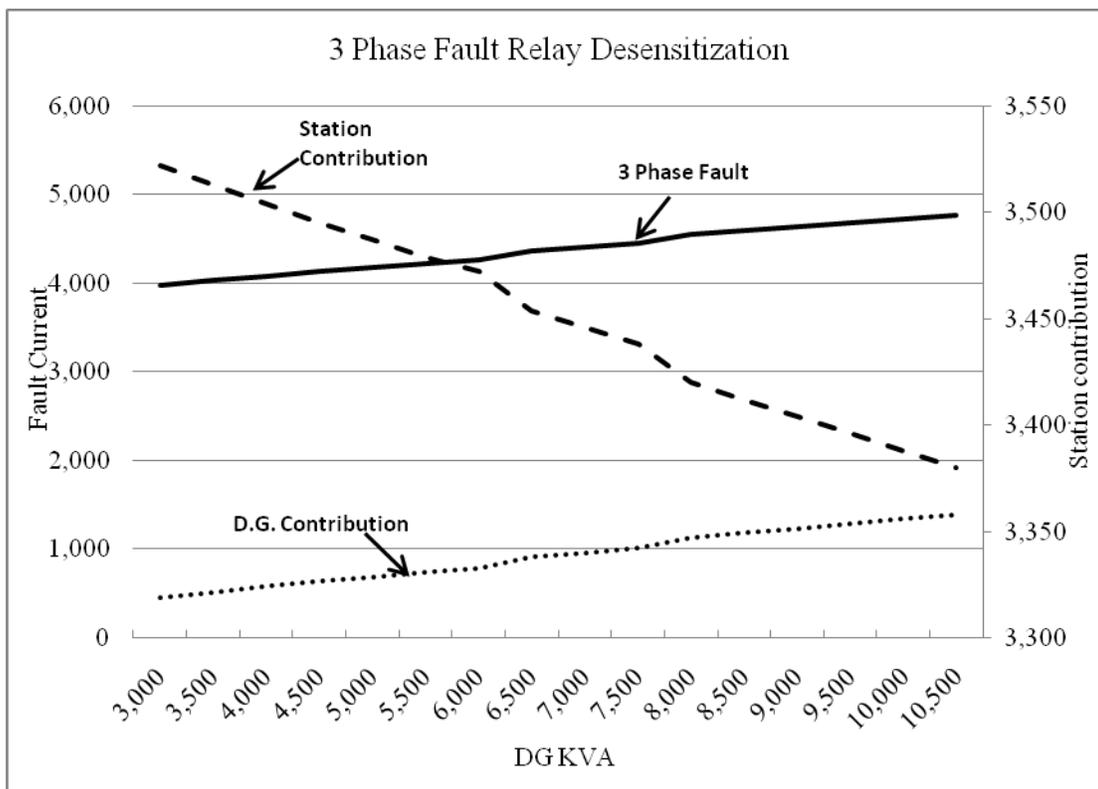
Table 1. Simulation Results for Relay Desensitization

| Generator               | Total Fault Current | Station Contribution | DER Contribution |
|-------------------------|---------------------|----------------------|------------------|
| KVA1                    |                     |                      |                  |
| <i>No DER Connected</i> | 3,591               | 3,591                | 0                |
| 3,000                   | 3,977               | 3,522                | 455              |
| 3,500                   | 4,030               | 3,513                | 517              |
| 4,000                   | 4,080               | 3,504                | 576              |
| 4,500                   | 4,129               | 3,495                | 634              |
| 5,000                   | 4,174               | 3,487                | 687              |
| 5,500                   | 4,218               | 3,479                | 739              |
| 6,000                   | 4,260               | 3,472                | 788              |
| 6,500                   | 4,361               | 3,454                | 907              |
| 7,000                   | 4,406               | 3,446                | 960              |
| 7,500                   | 4,450               | 3,438                | 1,012            |
| 8,000                   | 4,548               | 3,420                | 1,128            |
| 8,500                   | 4,594               | 3,412                | 1,182            |
| 9,000                   | 4,639               | 3,404                | 1,235            |
| 9,500                   | 4,683               | 3,396                | 1,287            |
| 10,000                  | 4,726               | 3,388                | 1,338            |
| 10,500                  | 4,768               | 3,380                | 1,388            |

Source: Provided by author

As shown by Table 10 and the associated Figure 13, although the total fault current increases for a fault at a specific location, the contribution from a fixed source (in this case the substation) decreases as the DER penetration increases. The steady decrease of fault current contributions from the station can eventually result in inability of the relays to sense the fault current and operate as it is intended. The graphs in Figure 14 represent the current contributions from each source as well as the total fault current for a 3-phase fault at the same location. Non-smooth steps in the station current are shown where the interconnection transformer has been changed to account for the increase in DER capacity.

**Figure 7. Relay Desensitization Characteristics**



Source: Provided by author