INVESTIGATING RULES, CRITERIA, AND CHALLENGES FOR INTERCONNECTION OF DISTRIBUTED GENERATION

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INVESTIGATING RULES, CRITERIA, AND CHALLENGES FOR INTERCONNECTION OF DISTRIBUTED GENERATION

A Project

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Abstract

The purpose of this project is to gather and document the existing criteria, rules, and practices used by the Investor Owned Utilities (IOUs) in California for physical interconnection of Distributed Generation (DG) and to identify existing technical issues and concerns associated with interconnections under the current rules. The criteria set by the National Standard IEEE 1547, California Public Utilities Commission (CPUC) Rule 21, and the standard practices used by a sample major IOU will be presented and compared. Implementation problems and issues associated with the presently used rules and criteria are documented and discussed. The project also intends to verify and further investigate any system protection related concerns using system modeling and simulations. Known protection related impacts due to relay desensitization and
overstressed equipment will be simulated using industry level software, and the results from the analyses will be presented. Suggestions and recommendations will be provided for future research and studies in the interest of developing future criteria and recommended practices for DG interconnections. The project summarizes problems and issues with the interconnection of increasing levels of DG, which is one of the topics of major focus in electrical power systems.

Statement of Collaboration

Charles Hoffman and Kunjal Yagnik have both made significant contributions to this project. Their contributions have been presented in Appendix “C”, where the collaborators can express a clear division of their efforts as well as provide organizational support for their respective project stages.

Statement of the Problem

Significant need lies in further development and implementation of standards and criteria for interconnection of DG through analytical methods, modeling and simulations, as well as from the experiences of industry experts. Currently, renewable resources DG is being interconnected to the existing IOU grids that were originally designed for passive loads only. Interconnection of active DG sources has introduced technical challenges for the developers as well as for the IOUs. The main goals of this project are; to provide a report on the existing rules and criteria, investigate their adequacies, and identify potentials for further improvements for interconnection renewable resources to the future electrical power grids.
Sources of Data

The primary sources of data have been the IEEE papers, Standards and rules form IEEE, CPUC, and major IOUs in California, and other documents listed in the references. Notes and test results presented in seminars and conferences on the subject have been used. Utility grade Short Circuit software has been utilized for computer simulation studies.

Conclusions Reached

In order to prepare the electric power system for smart grid load management and DG interconnection, well-established criteria for Planning /Design, System Protection/ Reliability, and Power Quality must be maintained throughout the electric power system. Additionally, major concerns should be modeled and simulated to obtain a more complete analysis of distribution level protection issues, which will further illustrate system impacts and promote new interconnection strategies.

Although a renewable resource DG will have great benefits for the society and the environment, increasing number of interconnections creates impact to the electrical power systems. Major system protection related impacts of “Protective Relay Desensitization” and “Increased levels of Overstressed Equipment” have been investigated and verified. The electrical distribution systems of the future must evolve in several important ways to be able to accommodate increasing number of DG interconnections. A complete systems approach, which addresses systems integration, must be taken in order to fully understand and alleviate the undesirable impacts of DG interconnections.
Further DG integration is still being accomplished despite lack of: (1) universally accepted approaches to systems impacts, (2) comprehensive analyses to account for grid modernization with DG, and (3) the prerequisite qualifications of modern interconnection systems. Satisfying these deficiencies will establish development of more effective, planning, building, operating, and maintaining of the modern grid, which includes DG.

_______________________, Committee Chair
Suresh Vadhva, Ph.D.

_______________________
Date
DEDICATION

We thank GOD for giving us the opportunity to work on this research project. We are honored to have worked on this very first research project in the establishment of California Smart Grid Center at California State University-Sacramento.

“I would like to dedicate my work on this project and related achievements culminating in this Master’s degree to my parents George and MaryAnn Hoffman. They have been everything one would hope to have in a mother and father. Their examples of hard work, caring, and overall support has been a driving force in my life.”

-Charles Hoffman

“I would like to dedicate my efforts for this project report and related accomplishments during this project, to my parents Kirit and Roopa Yagnik. Their efforts and support gave me enough courage to accomplish this task with the touch of perfection.”

-Kunjal Yagnik
Sincere thanks and appreciation are extended to Dr. Suresh Vadhva and Dr. Mohammad Vaziri for their vision, leadership, initiation of the project, and guidance for all technical concerns. Their tireless efforts often went beyond the scope of this project. The authors are also grateful to the faculty members of the CSUS Electrical and Electronic Engineering for sharing their knowledge and putting them on the path to becoming quality engineers.
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Chapter 1

INTRODUCTION AND BACKGROUND

The power industry is currently experiencing a modern revolution in terms of technology and strategies to alleviate the growing power demands. Additionally, significant increases in DG interconnections have materialized over the past few years and much more are requesting approval of interconnection. Environmental concerns and advances in these DG technologies are some of the driving forces behind the push for DG 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% by 2020 is expected in addition to the 20% 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% of generation coming from central & local renewable sources; (2) the reduction of Green House Gas (GHG) emissions to below 1990 levels; (3) the creation of zero net-energy facilities by 2020 & 2030. Energy efficiency and demand response policy objectives have already led to 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 DG 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 where extensive planning, long lead-time, and significant funding are required. 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 DG interconnections.

Distributed Generation (DG), Distributed Resource (DR), and Distributed Energy Resources (DER), that appear in various technical literature, all refer to small, local electric energy generating units from various resources. A DG has no distinction between 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 usually constructed in remote locations where their generated electricity must be transmitted for longer distances before reaching the load centers. A significant advantage of a DG is that it can help minimize 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.
Cautious interconnection of DG may prove beneficial to mitigate many of the existing power system issues. Mitigation of transformer overloading, decreased number of low voltage conditions, and improved power quality are among some of these benefits [12]. In comparison to traditional transmission topology where loads are served at the far end of the transmission network, DG provides specific benefits to the grid and other customers within the service territory. Currently, a variety of methodologies has been proposed to implement the use of DG to reduce peak load requirements and to improve load management. DG 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 DG by increasing the diversity of the power supply options. Other indirect ways DG can improve reliability are by reducing stress on grid components to the extent that the individual component reliability is enhanced. For example, DG 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 many technical and operational concerns that must be addressed for a safe and reliable integration of DG. Significant Planning / Design, Power Quality, and System Protection / Reliability problems arise when a DG is interconnected to the current distribution grids. One reason behind these problems is that the distribution system has not been designed for bi-directional power flow and DG 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 although; there are still many noteworthy issues.

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, should 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 U.S. grid and turn it into a “smart grid.” A smart grid has the following characteristics: [14]

a. Allows active participation by consumers in demand response (including distributed generation);

b. Operates resiliently against both physical and cyber attacks;

c. Maintains high power quality;

d. Accommodates all generation and storage options;

e. Enables new applications including: DG and load participation; self-healing capabilities, and provides an energy efficient operation;
f. 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 DG and the number of DG interconnections for every year.

![DG Interconnections and Capacity](image)

**Figure 1 DG Growth in California from IOUs**

The chart above shows the numbers of DG 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
Machines Based DG 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 DG. For example, systems incorporating a large penetration of wind power generation also may supplement with a battery system to account for variability of wind therefore improving reliability. Thus, there are noticeable increments in MW capacity of DG units every year. [15]

The main objectives of this project are as follows:

- Gather, document, and compare the existing rules and criteria used for DG interconnection;
- Investigate and identify major System Protection related issues and concerns associated with the interconnection of DG;
- 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 focus will be in three main areas: “Planning / Design”, “System Protection / Reliability”, and “Power Quality.”

The organization of the project chapters is as follows:

- Chapter 1: Introduction and Background;
- Chapter 2: Summary of Interconnection Requirements;
• Chapter 3: System Protection related Major Areas of Concern;

• Chapter 4: Modeling and Simulations addressing Protection Related Concerns;

• Chapter 5: Conclusions and Recommendations.

Commonly used definitions and acronyms as defined by the various standards and rules will be provided in the Appendix A and B, respectively. Appendix C provides details on collaborative work for the project. References are provided in the “Bibliography”.

Chapter 2

SUMMARY OF INTERCONNECTION REQUIREMENTS

In this chapter, a summary of interconnection requirements is provided composed from the current standards for interconnection of DG in California, which includes IEEE 1547, CPUC Rule 21, and a sampled IOU- PG&E.

Integration of DG 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 DG 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 DG interconnection, which recently adopted most of the interconnection criteria set by the IEEE 1547 standard. The main objective of either document was to establish a uniform set of criteria, rules, and procedures for interconnections of DG to the power distribution grids. Further, Rule 21 also provides an Initial Review Process (IRP), which can speed the process of DG interconnection. Generation Facilities, which do not pass the IRP, will be evaluated via what is known as the “Supplemental Review” process. In a Supplemental Review, further evaluations and studies are performed to determine any specific issues that maybe caused by the Generating Facility (GF) interconnection and to determine any mitigating solutions. The utilities have expanded on Rule 21 to create their own varying set of rules and guidelines. [7]
Summarized below are the interconnection criteria for IEEE 1547, CPUC Rule 21, and a sample IOU, PG&E.

2.1 National Standard IEEE 1547 [2]:

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

2.1.1 Planning / Design:

1. Per IEEE 1547, DG is not allowed to actively regulate the voltage, and that 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 ANSI Standard is shown in Table 1.
2. IEEE 1547-4.1.3 has a paralleling specification where the DG must parallel with the Area EPS without causing a voltage fluctuation at the PCC greater than ±5% of the prevailing voltage level of the Area EPS.

3. 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 DG.

4. 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.

5. Interconnection system must have the capability to withstand voltage and current surges according to IEEE Std C62.41.2-2002 or IEEE Std C37.90.1-2002.
2.1.2  System Protection / Reliability:

1. During the condition of inadvertent energization, the DG must not reclose into the Area EPS when the Area EPS is de-energized.

2. “The interconnection system paralleling device must withstand 220% of system rated voltage.”

3. The DG must detect and interrupt connection with the Area EPS for faults on the Area EPS circuit.

4. “The DG must not energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS.”

5. DG 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 DG 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 DG 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 DG 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 DG 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 DG Systems is less than 50% 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>
<thead>
<tr>
<th>Voltage range (% of base voltage)</th>
<th>Clearing time(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$V &lt; 50$</td>
<td>0.16</td>
</tr>
<tr>
<td>$50 \leq V &lt; 88$</td>
<td>2</td>
</tr>
<tr>
<td>$110 &lt; V &lt; 120$</td>
<td>1</td>
</tr>
<tr>
<td>$V \geq 120$</td>
<td>0.16</td>
</tr>
</tbody>
</table>

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

*b DG $\leq$ 30kW, maximum clearing times; DG $> 30$kW, default clearing times.
Table 3 shows the system response to abnormal frequencies and respective clearing times as stated by IEEE 1547 [2].

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

<table>
<thead>
<tr>
<th>DG size (kW)</th>
<th>Frequency range (Hz)</th>
<th>Clearing time (s)(^a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(\leq 30)</td>
<td>&gt; 60.5</td>
<td>0.16</td>
</tr>
<tr>
<td></td>
<td>&gt; 59.5</td>
<td>0.16</td>
</tr>
<tr>
<td>(&gt; 30)</td>
<td>&gt; 60.5</td>
<td>0.16</td>
</tr>
<tr>
<td>(&lt; (59.8 - 57.0)) (adjustable set point)</td>
<td>Adjustable 0.16 to 300</td>
<td></td>
</tr>
<tr>
<td></td>
<td>&lt; 57.0</td>
<td>0.16</td>
</tr>
</tbody>
</table>

\(^a\)DG \(\leq 30\) kW, maximum clearing times; DG \(> 30\) kW, default clearing times.

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

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

<table>
<thead>
<tr>
<th>Aggregate rating of DG units (kVA)</th>
<th>Frequency difference ((\Delta f,)Hz)</th>
<th>Voltage difference ((\Delta V,) %)</th>
<th>Phase angle difference ((\Delta \Phi,^\circ))</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-500</td>
<td>0.3</td>
<td>10</td>
<td>20</td>
</tr>
<tr>
<td>(&gt; 500 - 1500)</td>
<td>0.2</td>
<td>5</td>
<td>15</td>
</tr>
<tr>
<td>(&gt; 1500 - 10000)</td>
<td>0.1</td>
<td>3</td>
<td>10</td>
</tr>
</tbody>
</table>
2.1.3 Power Quality

1. Limitation of dc injection: “The DG and its interconnection system must not inject dc current more than 0.5% of the full rated output current at the point of DG connection.”

2. Limitation of flicker induced by the DG: The DG must not create out of limit flicker for other customers on the Area EPS.

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 DG connected.

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

---

1 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 ($I_{(1,2)}$)

<table>
<thead>
<tr>
<th>Individual Harmonic Order $h$, (Odd Harmonics)</th>
<th>Max Distortion ($%$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$h &lt; 11$</td>
<td>4</td>
</tr>
<tr>
<td>$11 \leq h \leq 17$</td>
<td>2</td>
</tr>
<tr>
<td>$17 \leq h \leq 23$</td>
<td>1.5</td>
</tr>
<tr>
<td>$23 \leq h \leq 35$</td>
<td>0.6</td>
</tr>
<tr>
<td>$35 \leq h$</td>
<td>0.3</td>
</tr>
<tr>
<td>Total demand distortion (TDD)</td>
<td>5</td>
</tr>
</tbody>
</table>

1. IEEE 1547-4.3.3

2. $I = \text{the greater of the maximum Host Load current average demand over 15}$

   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).

3. Even harmonics are limited to 25% of the odd harmonic limits above.

2.2 CPUC Rule 21 [3]:

The CPUC Rule 21 has adopted many of the inter-connection criteria set by the IEEE 1547. An important addition with Rule 21 is that it provides an Initial Review Process (IRP) where an efficient screening process of DG applications speeds up the interconnection process. Supplemental Review is provided for applicants not meeting the IRP criteria in which further review is required.
2.2.1 Planning / Design:

1. The DG 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% 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% 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% of the nominal ampere rating of the customer’s Service Equipment.

       • The total aggregate GF capacity must be no more than 50% 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% 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% 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. 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.
Fig. 2 flowchart shows the screening thresholds of the Initial Review Process.

Is the application process complete? → Complete the Application

1: Is the PCC on a networked secondary system? → Yes

2: Will power be exported across the PCC? → Yes

3: Is the Facility certified or does it have interim approval? → No

4: Is the aggregate DER capacity less than 15% of Line Section peak load? → No

5: Is the Starting Voltage drop requirement met? → No

6: Is the Gross Nameplate Rating of the Generating Facility 30kVA or less? → No

7: Is the Short Circuit Current Contribution Ratio requirement met? → No

8: Is the line configuration requirement met? → No

Does Supplemental Review determine requirements? → Yes

Interconnect without requirement → Interconnection with requirements → Interconnection needs detailed study

Figure 2 Initial Review Process Flowchart
2.2.2 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\(^2\) must be added at PCC. 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% of the interrupting rating of the utilities service equipment.

4. The Line Configuration is acceptable for Simplified Interconnection:

   i. 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

\(^2\) Fault Detecting schemes are referred to equipment that detect and interrupt multiphase and ground faults on the utility systems.
the Distribution System or other customer’s equipment caused by loss of system neutral grounding during the operating time of anti-islanding protection.

**ii.** 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% of the Line Section peak load must be reviewed. This screening process is to limit overvoltages to the Distribution System or customer’s equipment caused by loss of system neutral grounding during an Unintentional Island before the operating time of anti-islanding protection scheme. The 10% 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, the system response to abnormal voltages, has been adopted by Rule 21 where clearing time limits are specified.

6. Table 3, the system response to abnormal frequencies and the respective clearing times limits, has been adopted by Rule 21.

7. Table 4 has been adopted by Rule 21 and provides the required synchronizing parameter limits.

2.2.3 Power Quality:

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

2. DC injection limits: DC injection must be less than 0.5% of GF rated output current.

3. Table 5 specifies the limits on harmonic current injection into the Area EPS, has been adopted by Rule 21.

2.3 Interconnection Criteria set by PG & E:

PG&E has adopted the CPUC Rule 21 as its DG 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 DG interconnections, major focus is given to the Distribution interconnection handbook.

2.3.1 Planning / Design: [5]

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

1. Simplified Interconnections:

Small, certified, non-exporting generators are included in this category.

2. Supplemental Interconnection:

i. 15% Rule – The applicant’s generating system combined with existing generation does not exceed 15% 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.

2.3.2 System Protection / Reliability: [5]

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 PG&E Generator Protective Device Schemes

<table>
<thead>
<tr>
<th>Generator – Protection Device</th>
<th>Device Number ¹</th>
<th>Up to 40 kW</th>
<th>41-400 kW</th>
<th>Above 400 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase Overcurrent</td>
<td>50/51</td>
<td>X²</td>
<td>X²</td>
<td></td>
</tr>
<tr>
<td>Overvoltage</td>
<td>59</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Under-voltage</td>
<td>27</td>
<td>X¹</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Over-frequency</td>
<td>81O</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Under-frequency</td>
<td>81U</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Ground-Fault-Sensing Scheme</td>
<td>51N</td>
<td>X⁴</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Overcurrent with Voltage</td>
<td>51V/51C</td>
<td></td>
<td>X⁵</td>
<td>X</td>
</tr>
<tr>
<td>Restraint or Overcurrent with Voltage Control</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reverse-Power Relay</td>
<td>32</td>
<td>X⁶</td>
<td>X⁶</td>
<td>X⁶</td>
</tr>
<tr>
<td>Direct-Transfer Trip</td>
<td>TT</td>
<td>X⁷</td>
<td>X⁷</td>
<td>X⁷</td>
</tr>
</tbody>
</table>
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.

   The generator must be equipped with a phase instantaneous overcurrent relay that can detect a line fault under subtransient conditions.

   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.

3. For generators rated at 40 kW or less, installing a contactor undervoltage release may meet the undervoltage protection requirement.

4. If CPUC Rule 21 requires fault detection equipment, the ground fault detection is required for any noncertified inverter-based, induction, or synchronous GF.

   Synchronous generators with an aggregate generation over 40 kW and induction generators with an aggregate generation over 100 kW require ground-fault detection.

5. When CPUC Rule 21 requires fault detection equipment, then a group of generators, each less than 400 kW 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.

6. For nonexport GFs 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.
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% 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.

As a “reverse-power” element, the relay must be set for 0.1% of the transformer rating with a time delay of 2 seconds, as specified by the CPUC Rule 21.

7. PG&E determines, based on PG&E’s circuit configuration and loading, if the distribution-level interconnections require transfer-trip protection.

2.3.3 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 GF 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 exceed as defined by the “Maximum Borderline of Irritation Curve.”

2.4 Comparative Discussion of Various Criteria

DG standard IEEE 1547, establishes criteria and requirements for interconnection of DG with the Area EPS. The criteria for interconnection are specified in which the operation, performance, equipment conformance testing, safety considerations, and

3 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.
maintenance of the interconnecting facilities are evaluated. IEEE 1547 voltage requirements are stated, “to be met at the PCC” between the Local EPS and the Area EPS where an aggregate capacity 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. The existing limitations in the loading area (15% 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 are as follows:

1. PG&E has addressed the possibility for requiring a dedicated transformer, where as IEEE 1547 or Rule-21 have no 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 has not been 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.

Discussion and comparison of the criteria for interconnection DG in California for IEEE 1547, Rule 21, and PG&E has been presented and organized categorically by Design / Planning, System Protection / Reliability, and Power Quality. In the next chapter, Major Areas of concern for interconnection of DG are given.
Chapter 3

MAJOR AREAS OF CONCERN

In this chapter, the investigation and identification of major System Protection related issues and concerns associated with the interconnection of DG are given which include; Unintentional Islanding, Over-stressed Equipment, Relay Desensitization, Voltage Regulation and Flicker, Overloaded Transformer Replacement, and Ferresonance.

Connection of the distributed generation with the distribution system causes issues, which are 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.

3.1 Unintentional Islanding:

Unintentional islanding occurs when a portion of the distribution system becomes electrically isolated from the remaining power system, yet continues to be energized by DG outside of the utility’s control. For the network shown in figure 3, a possible unintentional island can occur when the circuit breaker “A” opens while DG units 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 DG units. Melting of 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” opens and fuse “F” 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 remaining network will continue to be energized by DG2.

![Figure 3 Typical Distribution System with DG](image)

There are several known conditions where islanded systems can be developed automatically. Transient faults, control failures, operator errors are among the known
conditions. Islanded conditions have also been created due to unknown conditions. DG 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 formation of islands. A widely used criterion is the one that considers an island maybe formed when the aggregate size of generating units is equal or larger than half of the load of the system at the instant of formation of the island. Options to prevent an island or to cease its continuation include; “Anti-Islanding Schemes” of inverter based units, Reverse Power relaying schemes, and Transfer Trip schemes.

Figure 4 shows Transfer Trip schemes referred to the DG’s PCC with the Local EPS.
Some operating scenarios may require opening the disconnect switch Y and closing the disconnect switch X. During such condition, DG2 in this example will no longer be connected to the substation 1 and will be transferred to substation 2. As a result, reclosers associated with substation 2 should also be monitored to decide the islanding status of DG2. The design of central algorithm must have capability to get the most up-to-date information about the current topology of the distribution system and modify protection...
and controls as needed. A communication channel such as Radio, Microwave, or a Leased Telephone line is used in this scheme. [17]

3.2 Overstressed Equipment:

Addition of generation sources to a distribution system increases short circuit currents at any location on the system. This increases the $I^2t$ levels for all equipment on the system. $I^2t$ 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 $I^2t$ value at its location exceeds the withstand capability of the equipment. $I^2t$ increases and associated impacts will be at maximum in vicinity of the additional unit.

For DG 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 $I^2t$ increases versus clearing times for 3-phase faults. For single line to ground faults, $I^2t$ value is calculated similarly.
Chapter 4 will provide a detailed analysis of the simulated cases on effects of $I^2t$ increases for an actual distribution system.

3.3 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 DG 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 6 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 DG. [6]

Figure 6 Relay Desensitization for Faults at F1

Chapter 4 will provide a detailed analysis of the simulated cases on effects of Relay Desensitization for an actual distribution system.
3.4 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. In instances, which 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 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. [6]

Another example of unacceptable voltage flicker is shown in Fig. 7. Here, a maximum voltage flicker for a full load rejection of a DG is shown. 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% 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% 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. [6]

![Figure 7 Minimum Load Voltage Profile](image)

3.5 Overloaded Transformer Replacement

Transformer replacement is a substantial issue for the interconnection of the DG 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 DG exceeds the nameplate rating of the transformer. However, PG&E allows overloading of the distribution transformers to over 140% of their nameplate
ratings [15]. It has been suggested that same criterion should be used for transformer replacement whether the overload is caused by DG integration or by actual increases in loading. This issue is currently under investigation by the Rule 21 technical committee.

Another cause of concern in 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 8 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 effected. [13]
Concerns:
- Can supply the feeder from an ungrounded source after substation breaker A trips causing overvoltage.
- Results in an unwanted ground current supplying faults at F1 & F2.
- Permits source feeder relaying at A to respond to a secondary ground fault at F3.

Advantages:
- No ground fault backfeed for faults at F1 & F2.
- No ground current from breaker A for a fault at F3.
- No ground current from breaker A for faults at F3.
- No overvoltage for ground fault at F1 if the gen neutral is Y-connected with a low-impedance ground.

Figure 8 Interconnection Transformer Configurations
3.6 Ferroresonance:

During islanding conditions, ferroresonance can occur with DG 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 it can occur with all three phases connected. Ferroresonance condition is likely to happen in the DG 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% 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 9. 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 DG 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. [9]

![Figure 9 Typical Power System Configuration Favorable to Ferroresonance](image)

Most prevalent concerns about interconnection of DG to the typical distribution systems of the IOUs have been discussed here. In the next chapter, selected concerns of “Relay Desensitization” and “Overstressed Equipment” will be further investigated using computer simulations.
Chapter 4

MODELING AND SIMULATIONS

In this chapter, results of the computer simulations using a short circuit program that is currently being used by some of the major IOUs are presented and discussed. Two sets of simulations were performed for this study. The first simulations address desensitization of relays at the substation as a function of progressive DG capacity increases. The second simulations are about the effects and variations of the $I^2t$ levels due to added DG at various levels.

4.1 Relay Desensitization:

Relay desensitization effects increase as the total capacity of the DG interconnected to a feeder increases. Simulations using short circuit software commonly used by the major utilities validate the results. The interconnection of DG increases the total fault current for any point on feeder. However, it also tends to decrease the contribution from the source station as well as other DG sources. In the simulated system, a variable size DG is connected at the far end of the network. The connection of the main transformer for the DG 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. Here ground faults were not considered and the focus of these simulations was 3 phase faults. [7]
Figure 10 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 end of the line faults where the effects of “Relay Desensitization” are notably displayed.

Figure 10 Transformer Configuration for Relay Desensitization

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

Results and Analysis

Simulations are used to verify that successive increases in the DG KVA ratings will result in relay desensitization from each of the source substation. During simulations, the
resulting current contributions from the substation were decreased with successive increments in the DG 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 7 shows the detailed results of the simulations.

<table>
<thead>
<tr>
<th>Generator KVA1</th>
<th>Total Fault Current</th>
<th>Station Contribution</th>
<th>DG Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>No DG Connected</td>
<td>3,591</td>
<td>3,591</td>
<td>0</td>
</tr>
<tr>
<td>3,000</td>
<td>3,977</td>
<td>3,522</td>
<td>455</td>
</tr>
<tr>
<td>3,500</td>
<td>4,030</td>
<td>3,513</td>
<td>517</td>
</tr>
<tr>
<td>4,000</td>
<td>4,080</td>
<td>3,504</td>
<td>576</td>
</tr>
<tr>
<td>4,500</td>
<td>4,129</td>
<td>3,495</td>
<td>634</td>
</tr>
<tr>
<td>5,000</td>
<td>4,174</td>
<td>3,487</td>
<td>687</td>
</tr>
<tr>
<td>5,500</td>
<td>4,218</td>
<td>3,479</td>
<td>739</td>
</tr>
<tr>
<td>6,000</td>
<td>4,260</td>
<td>3,472</td>
<td>788</td>
</tr>
<tr>
<td>6,500</td>
<td>4,361</td>
<td>3,454</td>
<td>907</td>
</tr>
<tr>
<td>7,000</td>
<td>4,406</td>
<td>3,446</td>
<td>960</td>
</tr>
<tr>
<td>7,500</td>
<td>4,450</td>
<td>3,438</td>
<td>1,012</td>
</tr>
<tr>
<td>8,000</td>
<td>4,548</td>
<td>3,420</td>
<td>1,128</td>
</tr>
<tr>
<td>8,500</td>
<td>4,594</td>
<td>3,412</td>
<td>1,182</td>
</tr>
<tr>
<td>9,000</td>
<td>4,639</td>
<td>3,404</td>
<td>1,235</td>
</tr>
<tr>
<td>9,500</td>
<td>4,683</td>
<td>3,396</td>
<td>1,287</td>
</tr>
<tr>
<td>10,000</td>
<td>4,726</td>
<td>3,388</td>
<td>1,338</td>
</tr>
<tr>
<td>10,500</td>
<td>4,768</td>
<td>3,380</td>
<td>1,388</td>
</tr>
</tbody>
</table>
As shown by Table 7 and associated Figure 10, 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 DG 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 11 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 DG capacity.
4.2 Measuring Effects of $I^2t$

Simulations using the same short circuit software demonstrate the effect of $I^2t$ increases with respect to increases in the DG 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. The interconnection of DG 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 DG is connected at far end of the network. Figure 12 shows the simplified network topology. Depending on the size of the DG units and interconnection transformer, the current to the faults varies in direct relation.

![Transformer Configuration for Overstressed Equipment](image)

**Figure 12 Transformer Configuration for Overstressed Equipment**
A three-phase fault is simulated at end of the line by varying the KVA ratings of the DG to see the change in short-circuit current at the fault point that includes contribution of the DG 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 time values from taken from typical relay settings and “Time vs. Current” characteristic curves that had been used for both the substation feeder breaker as well as the DG circuit breaker. The values obtained for current and time provided for the calculations of the $I^2t$ values.

Results and Analysis

Multiple simulations are used to verify the results. Increasing the KVA rating of the DG showed an increase in the total short circuit current. As discussed above, the current contribution from the source substation decreases as the DG capacity is increased. With the decrease in the fault value, longer time is taken to clear the fault form the substation, while the total fault value is increased. Therefore, the total $I^2t$ values at all fault locations on the feeder are conceivably increased. This has also been verified by the calculated values suggested by Table 8.
Table 8 Simulation Results for $I^2t$

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

The values of current and time and the actual values of $I^2t$ are calculated for the DG contribution, and substation contribution for total $I^2t$ for the fault. Given below is the sample calculation for the first reading.

\[
I^2t_{(DG)} = 352^2 \times 2.3 = 2.8 \times 10^5
\]

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

The individual $I^2t$ contributions from the station and DG are added to find the total $I^2t$ values. Given below is Table 9 displaying individual $I^2t$ contributions.
The DG relay experiences a steady rate of increase in current while the contribution from the station decreases with each increase in DG capacity. Therefore, the rate of changes the $I^2t$ levels contributed by the DG is much steeper than what is contributed by the station. The graphs in Figure 13 show the $I^2t$ variations contributed by each source as a function of increasing total DG capacity.

<table>
<thead>
<tr>
<th>Generator</th>
<th>$I^2t$ station</th>
<th>$I^2t$ DG</th>
<th>Total $I^2t$</th>
</tr>
</thead>
<tbody>
<tr>
<td>No DG</td>
<td>6.5X10^6</td>
<td>0</td>
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Computer simulations have been provided where de-sensitization of relays and the effects of increased $I^2t$ levels were addressed. In the next chapter, a review of conclusions reached in this project as well as future recommendations for interconnection of DG and the proposed “Smart Grid” are provided.
Chapter 5

CONCLUSIONS & RECOMMENDATIONS

In this chapter, presented is a review with concluding remarks and recommendations summarizing the DG interconnection rules and standards, system protection related concerns, computer simulations, and future developments.

5.1 Conclusions:

This project researched and documented the existing rules and criteria for interconnection of DG in one document. Unresolved system issues and concerns due to DG 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 DG are subject to interpretation by the utilities. These documents also fail to address some major areas of concerns 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 DG. Documentation of the existing criteria, rules, and issues categorized under “Planning / Design”, “System Protection / Reliability”, and “Power Quality”, will be beneficial in to entities seeking DG 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 DG 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 presented results from the simulations validated the concerns and issues raised by this IOUs.

Verification of the Effects of Relay Desensitization was provided through simulations. These simulations showed that successive increases in the DG capacity would result in relay desensitization of the station relay. That is, with each increment in DG 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 DG penetration exceeds a certain limit.

Effects of $I^2t$ provide insight to what extent the equipment is experiencing stress whether thermal or mechanical. Shown in simulations is the rapid increase of fault current per increased capacity of the DG. The increase in the DG capacity is in inversely proportional to the station current contribution for the fault though, overall $I^2t$ effects showed significant increases. This validates the concern about the added the stress levels for the equipment on the distribution network as the DG penetration increases.

Further research will 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 DG becomes a streamlined process, this project is a step in the direction of circumventing some of the current issues related to DG interconnections.

5.2 Recommendations:

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

Further development of DG 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 DG. [8]
APPENDIX A
Definitions

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

A.1 Definitions from National Standard IEEE 1547:

• Generating Facility (GF): Electric generation facilities connected to an Area EPS through a Point of Common Coupling (PCC); a subset of DG.

• 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.
A.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 DG 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 DG unit(s) to an Area EPS.
- Point of common coupling (PCC): The point where a Local EPS is connected to an Area EPS.
Figure 14 Example Distribution Feeder

- Point of distributed resources connection (point of DG connection): The point where a DG 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.

A.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 an 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% drop).
• Transfer Trip: A Protective Function that trips a Generating Facility remotely by means of an automated communications link controlled by PG&E.

A.4 Definitions from Other Sources:

• DG System Impact: DG interconnection can result in electric grid operating conditions that normally would not occur without the DG installed—these resulting conditions are called as DG 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 is called as null point. [18]

• Ferroresonance: A phenomenon characterized by overvoltages and very irregular wave shapes, which are potentially damaging to a transformer. 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.
APPENDIX B

Acronyms

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<tr>
<th>Acronym</th>
<th>Description</th>
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<tr>
<td>AC</td>
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<td>ANSI</td>
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<td>Area EPS</td>
<td>Area Electric Power System</td>
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<td>CAISO</td>
<td>California Independent System Operator</td>
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<td>CB</td>
<td>Circuit Breaker</td>
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<td>California Energy Commission</td>
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<td>DC</td>
<td>Direct Current</td>
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<tr>
<td>DG</td>
<td>Distributed Generation</td>
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<tr>
<td>DER</td>
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<td>DOE</td>
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<td>DR</td>
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<td>EPS</td>
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<td>IEEE</td>
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<td>PCC</td>
<td>Point of Common Coupling</td>
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<td>Pacific Gas and Electric Co</td>
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<td>R.M.S.</td>
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APPENDIX C

Division of Tasks

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BIBLIOGRAPHY


[10] Phil Barker, Overvoltage Considerations in Applying Distributed Resources on Power Systems, Reprinted from IEE PES (Power Engineering Society) Summer Meeting, 2002


