Solutions for Distributed Generation Protection and Control Issues

IPCGRID March 28, 2018

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Pacific Gas and Electric (PG&E)

- Peak Demand PG&E: 23 GW
- California Control Area: 58 GW

- 40,000 Protective Relays
- 100+ RAS and SPS
- 300,000 Solar Connections
- 23,000 Employees
- 141,215 Circuit miles of electric distribution lines
- 18,816 Circuit miles of electric transmission lines
- 5.3 million Electric customer accounts
- 67 Hydroelectric powerhouses

California Major Electric Transmission Lines

Legend:
- Pacific Gas & Electric (PG&E)
- Southern California Edison (SCE)
- Imperial Irrigation District (IID)
- Los Angeles Dept. of Water & Power (LADWP)
- San Diego Gas & Electric (SDG&E)
- Sacramento Municipal Utility District (SMUD)
- Pacific Gas & Electric (PG&E)

Map showing California's major electric transmission lines.
Drivers for Renewable Energy
California Legislation

- Reduce Greenhouse gas emissions by 40% from 1990 levels via:
  - Senate Bill SB 32
  - AB 197

- Increase Energy Derived from Renewable Energy Sources to 50% by 2030 via:
  - Senate Bill SB 350

- Renewable Portfolio Standard (RPS) Targets
  - 25% by end of 2016 (presently at 29%)
  - 33% by end of 2020
  - 40% by the end of 2024
  - 45% by the end of 2027
  - 50% by the end of 2030
  - No less than 50% in each multiyear compliance period thereafter.
  - 12000 MW from DER by 2020 (DER is defined as generation ≤20MW)
DG Protection Issues

Existing Interconnection requirements

- The existing California Rule 21 recognized that DER operating within the existing distribution system design parameters, with no reverse flow, has minimal system impact.

- Identified the low impact conditions (Initial Review Screens) and provided simplified requirements to allow small DER units at low penetration levels to be interconnected quickly as long as safety issues are addressed.

- Using the existing grid’s operating margin to enable fast DER interconnection significantly simplified the review/approval process and reduced the interconnect review time for the small units.

- Currently, the NEM PV units less than 30 kW can be approved and interconnected in 3 days at PG&E.
DG Protection Issues

- PG&E currently has over 3,000 MW and 300,000 installations of DER interconnected
- 5000/6000 installations per month.
- Presently at 15% of maximum and 45% of minimum load system wide
- Many feeders have 50-100% penetration at maximum load.
### Rooftop Solar

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<tr>
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<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>Delta from -1Y</th>
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Delta Previous Year: 29.04% 66.92% 58.65% 51.20% 6.10% -20.34%

### Utility Solar

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<td>740</td>
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Delta Previous Year: 23.10% 4.39% -12.05% 60.87% 43.24% 10.28%
DG Protection Issues

The Proliferation of DER installations is resulting in High Penetration and Bi-Directional Power Flows

- Results in fault clearing issues for faults on the sub-transmission and transmission system.
- Overvoltage
- Relay desensitization.
- Relay directionality may be required.
- Voltage regulation issues.
DG Protection Issues

With the proliferation of DG: 5k-6k/mo.

Safety needs to be the primary goal.

- Faulted conditions shall be detected and all generation sources removed from the faulted circuit.
- Timely fault clearing minimizes equipment damage.
- Accomplished by isolating the faulted component as quickly as possible.
DG Protection Issues

- **Interconnection Protection**
  - Protect *utility personnel* from feeders that should be de-energized
  - Protect the *utility and DER* from
    - Abnormal operating conditions
    - Fault backfeed
  - Protect *other utility customers* from poor power quality

- **Fault types**
  - **Phase faults**
    - Phase-Phase - Slack span, wind, car pole or other force cause the conductors to slap together.
    - Three phase - Down pole, storm, car pole, or other conductor failure.
    - Open conductor - Failure of conductor, splice or insulator
  - **Ground faults**
    - Phase-ground - Tree contact, conductor down from various means.
  - **Combination faults**
    - Double –Line ground - Multiple phase conductors and ground involved.
DG Protection Issues

- Generation Type Characteristics During Faulted Conditions:
  - Synchronous
  - Induction
  - Inverter Based
- Each type has a different fault current response.
DG Protection Issues

Traditional Generation fault current characteristics

- Synchronous Generation
  - Produces phase fault current in 3 stages.
    - $X''$d Subtransient: High level fault current (8-12pu) typically lasts approximately 5-6 cycles
    - $X'$d Transient: Lasts 10-12 cycles
    - $X$s Synchronous: Fault current magnitude can range from 1.0 – 1.2 pu.
  - Produces $I_2$ and $I_0$ current.
  - Voltage source model
  - Modeling is very well understood and repeatable.
    - Manufacturers provide test data to populate the required parameters.
  - Existing fault simulation software provides good modeling which has been validated with actual fault data.
  - Traditional protection relays are designed around these characteristics.
Renewable Types

Wind
Type 3

- No GND, No 3Io
- May have I2
- Crow Bar 2-3 Cycles
- Stator Connected to Grid
- Converter Controls Excitation

Wind
Type 4

- No GND, No 3Io
- No I2
- No Inertia
- May have short current spike
- Low fault current (1.1-1.3 pu)
- Similar to PV Inverter

PV

- No GND, No 3Io
- No I2
- No Inertia
- May have short current spike
- Low fault current (1.1-1.3 pu)
DG Protection Issues

Inverter Based Generation fault characteristics

- PV (photovoltaic)
  - Does not have the rotational inertia of the rotor and excitation of the field.
  - Generally a current source with minimal voltage support.
  - Traditional protection methods may not work.
    - Produces low level fault current typically 1.1-1.3pu.
    - Most inverter models do not produce I2 or I0.
  - The fault characteristic is dependent on the inverter switching control which varies among manufactures.
  - Tradition fault software is not configured to accurately model inverter based generation.
  - Fault simulation software presently uses a synchronous generator model that is modified to approximate the characteristics of an inverter, however this is still a voltage source model that does not adequately represent the actual fault current characteristics and voltages.
DG Protection Issues

Inverter based generation fault characteristics PV (photovoltaic)

Typical short circuit fault current for Synchronous Machines
DG Protection Issues
Inverter Based Generation fault characteristics PV (photovoltaic)

- IEEE PSRC C24 working group and EPRI has been working on a model that can be used in traditional fault simulation software.
- It uses a voltage controlled current method which also varies by voltage and power factor.
- An example of the required Aspen data is provided on right.
DG Protection Issues

- Traditional Methods of Fault Detection
  - They do not work well for phase faults with Inverter-based generation.
    - Due to the low level of fault current.
    - The variable nature of renewable generation.
      - Cannot set the protection low enough without limiting full rated output.
    - Lack of zero and negative sequence current can affect ground fault overcurrent detection and relay directional elements (if used).

- Note: Ground fault detection can be implement with Inverter-base generation. If the interconnecting XFMR is a Wye/Delta, the broken delta voltage or zero sequence current can be monitored.
DG Protection Issues

• Alternative Protection Methods:
  • DTT – System protective element sends trip to generation via communication.
    • Expensive to implement and maintain.
  • Allow load to swamp the generator.
    • 2X minimum load is required to ensure generation is swamped via undervoltage and frequency elements.
      • Higher penetration on distribution feeders is making this difficult to achieve.
    • Undervoltage, or negative sequence elements may be applied but may not operate for a high impedance fault and negative sequence may not operate due to the lack of negative sequence current from inverter based generation.
  • Use of UL 1741 and UL 1741SA “Anti-Islanding” certification.
    • Most common method is frequency bumping, however interaction with other generation may desensitize or defeat the scheme.
DG Protection Issues

DTT can be expensive and time consuming to implement (250k per terminal for lease line) in addition to reoccurring lease line cost.

- Implemented a lease line DTT Reduction Strategy.
  - Approved Use of 900Mhz spread Spectrum Wireless for DTT application.
- Developed DTT exemption process for evaluation of interconnections to remove the need for DTT.
  - Utilizing certified anti-islanding for tripping.
  - Based on size of generator in relation to load and other generation on the line section.
900 MHz Spread Spectrum Antenna

900 MHz Spread Spectrum Transmitter

- Spread Spectrum is limited to a distance of approximately 15 miles.
- Line of site.
Certified Inverter Islanding detection methods:

- There are various methods to detect islands, the two main methods are:
  - Sandia Frequency Shift: Utilizes positive frequency feedback for islanding detection. Frequency of the output voltage has positive feedback applied in proportion to the formula below:
    \[ f = K(f_a - f_{line}) \]
  - Where:
    - \( K \) = acceleration gain
    - \( f_a \) = measured frequency of \( V_a \)
    - \( f_{line} \) = line frequency
DG Protection Issues

Inverter Islanding detection methods:

• Sandia Frequency Shift (cont):
  • When connected to the utility minor frequency changes are detected and the inverter tries to change frequency but the stability of the grid prevents any change.
  • When the utility is disconnected $fa$ error increases and the PV inverter frequency increases until the inverter trips on overfrequency protection.

• Sandia Voltage Shift:
  • Applies positive feedback to the amplitude of $Va$. If there is a decrease in the amplitude of $Va$ the inverter reduces its current output and thus power output. When connected to the utility there is little of no effect when power is reduced.
  • When the utility is removed and there will be a reduction in $Va$ there will be a further reduction in the amplitude of $Va$ leads to a reduction of PV output current leading to a further reduction of voltage the can be detected by undervoltage protection.
DG Protection Issues

- Even with the exemption paper and adoption of the 900Mhz spread spectrum DTT system, a more streamlined protection approach was needed.

- The major issue was whether a feeder with mixed certified inverters would interfere with each other resulting in delayed tripping > 2 seconds.

- Comprehensive testing was performed to evaluate how mixed certified inverters would interact in an unintended island.

- Thru the CA CSI-3 funding, GE & PG&E collaborated on a 4 year unintended islanding study to better understand the probability of unintended islands with multiple certified inverters.

- Extensive load modelling was done.

- Over one thousand tests with different combinations of actual certified inverters and simulated loads, using two GE power amplifiers and RTDS, were conducted.
Unintended Islanding Study

Analysis of Test Results
Pure motor loads outlast composite loads

Island Duration vs. Penetration

- CMPLDs
- MotorB

- MotorB
Unintended Islanding Study
Islanding test results

Measured island durations
UL1741 limit is 2sec

Island Duration Histogram

- Public
Unintended Islanding Study
Impact of load power factor on duration -note that PV inverters are set at unity PF

- Island Duration vs. Penetration
- Data points for different power factors:
  - PF = 0.98cap
  - PF = 1.0
  - PF = 0.98ind
  - PF = 0.95ind
The islanding study showed that multiple inverters each certified to IEEE-1547-2003, on the same island, will trip within 2 seconds.

It also showed that the probability of multiple inverters, with potentially different anti-islanding schemes, interacting in a consistent way and causing extended run-on time is highly unlikely.

As a result, PG&E modified the existing DTT exemption bulletin to enable the quick interconnection of certified inverters if there are no significant machine based generators within the island.

Results of the islanding study did not include non-certified or synchronous machines. Since it was unknown how much uncertified DER would create a run on island. Therefore a limit of 10% non-certified to total DER was implemented.

It was thought the majority of DER would be certified inverter based, therefore this should not be an issue......
Additional Considerations

- California Air Resources Board (CARB) instituted new Methane Reduction rules to 40% of 2013 levels by 2030.
  - Dairy farmers and landfills have started installing methane fueled synchronous generators.
  - Due to the California drought many farms have installed electric ground water pumps for irrigation. The pump load is offset by PV generation.
  - Needed to determine if machine base generation would affect or desensitize the anti-islanding capability of the certified inverters.
  - Simulations performed by 3rd party interconnections have indicated a 40% mix of methane fueled synchronous generator operating in a fixed power factor mode with certified inverter based generation will trip in < 2 seconds.
DG Protection Issues
Machine/Inverter Simulations at 31% ratio

If the PV dominates the island it will drive the island frequency
DG Protection Issues
Machine/Inverter Simulations at 31% ratio

- As frequency increases, synchronous generation load will shift to the inverter generation.
- All generation tripped on over-frequency at 0.678 seconds
DG Protection Issues

As a result of the simulations, the amount of mixed generation types has increased from 10% to 40%.

**Flow Chart 1 - Distributed Generation Requirements for Distribution Circuits**

**Box A Requirements:**
Direct Transfer Trip (DTT) and ground fault protection are not required.

**Box B Requirements:**
Ground Fault Protection and Reclose Blocking.

**Box C Requirements:**
PGE Scadas Equipped Recloser.

**Box D Requirements:**
Customer side UG Interrupter or OH Recloser to be installed if not present.

**Box E Requirements:**
Redundant sets of PGE approved, protection relays installed by customer. These specific relay device numbers are 27, 59, 810, 811, 51X or 51C.

**Notes:**
1. PG&E, at its discretion may still require DTT on any DG system. (Especially machine based generators that cannot detect phase and ground End of Line faults.)
2. Phase and Ground protection are required to detect End of Line Faults.
3. These exemptions do not apply to certified and non-certified inverters with Stand-Alone capabilities.
4. Transmission DTT requirements are independent and still apply.
5. For a line section with all certified inverters, reclose blocking will not be required if the first reclose can be delayed to 10 seconds.
6. If an existing uncertified DG already has DTT then this uncertified DG would not count towards the 10% limit for the “other machine or uncertified DG...” screen. Other uncertified DG with previously approved protection may still need to be re-studied on a case by case basis.

**Diagram Description:**
- Certified Inverter
  - < 40 kW
  - Yes: Line Section: Aggregated DG > 50% of Minimum Load
  - No: > 40 kW
    - Yes: Line Section: Aggregate/DG > 40% or Uncertified DG is > 10% of the Aggregate DG (all types)
    - No: SCCR is > 10%
  - No: ≥ 1,000 kW
    - Yes: Line Section: Aggregate Machine > 40% or Uncertified DG is > 10% of the Aggregate DG (all types)
    - No: SCCR is > 10%

- Uncertified Inverter
  - < 40 kW
  - Yes: Line Section: Aggregated DG > 50% of Minimum Load
  - No: SCCR is > 10%
  - Yes: Line Section: Aggregated DG > 50% of Minimum Load
  - No: SCCR is > 10%
  - Yes: Line Section: Aggregated DG > 50% of Minimum Load
  - No: SCCR is > 10%

**Box A**
Direct Transfer Trip (DTT) and ground fault protection are not required.

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Ground Fault Protection and Reclose Blocking.

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Due to the increased DER backfeed into the transmission system the following screen has been developed.
DG Protection Issues  DTT Minimization

Machine based generation section has been added.
DG Protection Issues

DG Backfeed Generation Example

The method is based on sectionalizing and evaluation of zones.
- XFMR
- Substation
- Line Section
  - Each section is evaluated based on the section generation make-up criteria

Line Section
Station
Transformer
Additional High Penetration Considerations.

**Overvoltage Issues**

- PG&E Distribution XFMRs are typically HV grounded however there are many fused with the HV winding ungrounded, and several that are Delta connected.
- High penetration DER can result in overvoltage issues.
  - High penetration is >50% of minimum load.
- Transmission protection systems isolate the fault from the grid.
- DER keeps unfaulted phases energized at Line-Line Potential.
- System must be insulated to withstand magnitude (1.73pu) and (2 seconds) of over-voltage.
Additional High Penetration Considerations

**Ground Fault Overvoltage**

Grounding of fused transformers requires:
- Removal of the fuses.
- Installation of a three phase interrupting device with adequate protection.
- Existing station footprint not large enough to allow extra equipment.
- May need to install or replaced control building.

Delta transformers would require a grounding bank.
- Installation would require a 3 phase interrupting device.
- Installation of transformer protection package.
- Entail the same limitations as the fused bank above.

The majority of the PG&E Transmission System is operated effectively grounded worked with Substation and Transmission Line Asset group to determine if equipment could withstand short duration overvoltage.
- Review of transformer specifications.
- Substation insulators
- Lightening Arrestors
- Circuit breakers
- PT/CCVT’s
- Transmission line insulators

*It was determined most equipment could withstand steady state 1.73pu voltage for 2 seconds, however the breaker voltage across the open poles of the interrupter during the island due the voltage phase shift needs to be evaluated very closely to determine if it exceeds the manufacture rating. This may result in a the tripping time-delay of less than 2 seconds.*
Due to Frequency Shift of islanded generation
Could have $\Delta V = 2.73 \text{ Vpu}$ across breaker
Overvoltage Mitigation

- **Trip generation source quickly via phase voltage monitoring (ie 20 cycles).** Use of phase voltage instead of traditional 3Vo monitoring is that unlike 3Vo monitoring the phase overvoltage condition will only occur once the utility source is disconnected therefore coordination with other protection is not required.

- **Back-up scheme in place to take action if the primary scheme fails.** (ie Breaker fails to open)
  - **Certified Inverters** - The transmission overvoltage detection scheme at the substation trips the feeder breaker after a short time delay. (the inverter anti-islanding scheme is the back-up trip scheme)
  - **Synchronous Generation** - Install DTT keyed from the transmission line relays to trip generation. For synchronous generation this should already be installed for anti-islanding purposes. The Overvoltage scheme will operate if the DTT or generator breaker fails.
Streamlining Protection Requirements

Summary

- The current UL 1741 certification has been shown to be effective at ensuing the multiple inverter installations trip within 2 seconds.
- This has allowed for the rethinking of the DTT requirement resulting in significant reductions in the requirement.
  - Presently running simulations to quantify the mix of machine/non-certified to certified inverters. In addition to determining the affects of TOV and ground overvoltage conditions.
  - This may result in changes to the existing DTT requirements.
• Characteristics and behavior of the system are changing
  • Rapid penetration of new types of electronically-coupled resources
  • Inverter Based Sources
  • Battery Storage Systems.
  • Traditional protection schemes may not be adequate in some cases.
  • Includes Distribution Connected Synchronous generators.
  • More studies are being performed to determine the amount of machine to certified inverter based DER at which point an unintended island can remain on-line > 2 seconds. Results expected 2nd Quarter 2018.
• Need to be flexible and think outside the box.

Change is Coming

1890 DC  1910 AC  1990  2010
Questions?