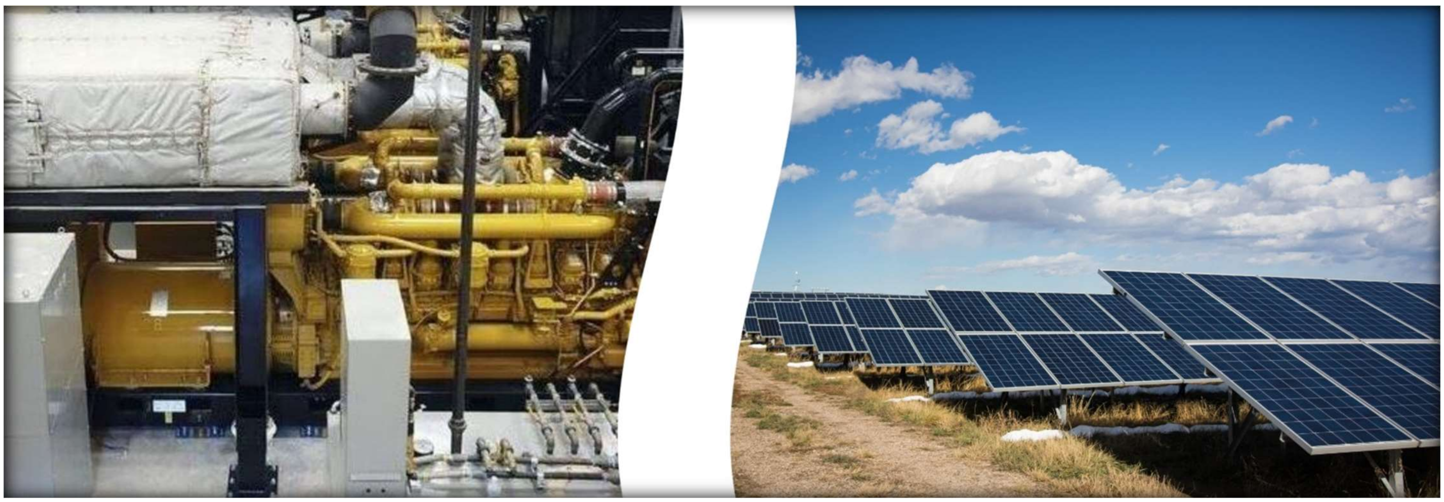
DISTRIBUTED ENERGY RESOURCE SYSTEM IMPACT STUDY REQUIREMENTS



SCAMPS

2019 ANNUAL MEETING

PRESENTED BY:

UTILITY TECHNOLOGY ENGINEERS-CONSULTANTS

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1. INTRODUCTION

1.1 WHAT IS A DISTRIBUTED ENERGY RESOURCE (DER)?

A Distributed Energy Resource, Industry acronym DER, is defined by IEEE 1547, *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Power Systems Interfaces,* as:

> "A source of electric power that is not directly connected to a bulk electric power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS." (Electric Power System)

Typical examples of DERs are:

- Photovoltaic (solar plant) installations
- Battery installations
- Diesel/natural-gas/landfill-gas/bio-gas generation plant installations

In today's electric utility environment, developers are approaching electric utilities with requests to connect DERs to the utility's electric system. Such generation assets create operating issues within the EPS that should be addressed during the early stages of a project before the project is approved.

1.2 WHY IS A SYSTEM IMPACT STUDY REQUIRED BEFORE APPROVING A DER INSTALLATION?

DERs generally do not operate full time. A solar facility does not operate at night or during cloudy or inclement weather, and output can fluctuate as clouds move in and out. Peak shaving generation facilities typically only operate during certain load conditions, but are not intended to operate full time. Such short time or intermittent operations cause adverse electric system performance that can make a significant impact on customer service. The electric system's performance must be taken into consideration before a DER project is approved.

Issues that should be addressed include:

- Reverse Power Flow
- DER Capacity vs System Load
- Steady State Voltage Variations
- Transformer LTC / Voltage Regulator Interaction
- Voltage Flicker
- DER Step-up Transformer Winding Connections and Grounding Connections
- Ground Fault Over-Voltage
- DER Fault Current and Coordination
- Unintentional DER Islanding

2. EXAMPLE DISTRIBUTION SYSTEM

Consider the example typical distribution substation shown in Figure 1.

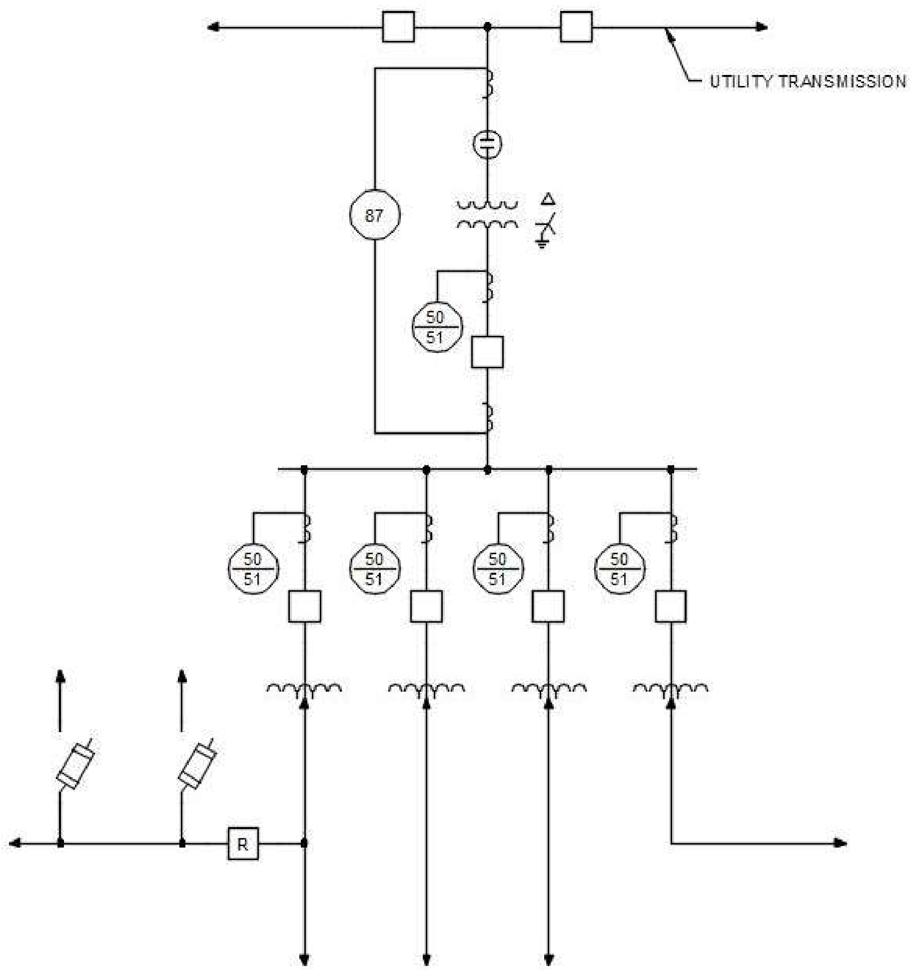


Figure 1 - Typical Distribution Substation

The typical distribution substation includes:

- A transmission system service, say 100 kV
- A substation transformer with the windings typically connected delta on the transmission voltage side and grounded wye on the distribution side, say 12.5 kV
- A main 12.5 kV circuit breaker and a 12.5 kV circuit breaker and voltage regulators for each feeder. In our example, we have shown four feeders, but to minimize clutter, we have not shown switches, transfer buses, etc.
- Relaying would typically be over-current for each breaker, perhaps feeder breaker blocking of the main breaker fast bus trip for down-line faults, and transformer differential relaying.

- Each feeder serves customers along the lines and tap lines and usually includes down-line reclosers and/or fuse protection.
- Because of line voltage drop, voltage regulators are set to raise taps during heavy loads and lower taps during light loads. Fuses, reclosers, and breakers are properly coordinated to provide reliable service with minimum outages during fault conditions.

Now consider the same example system with a DER installed along one of the four feeders, Figure 2.

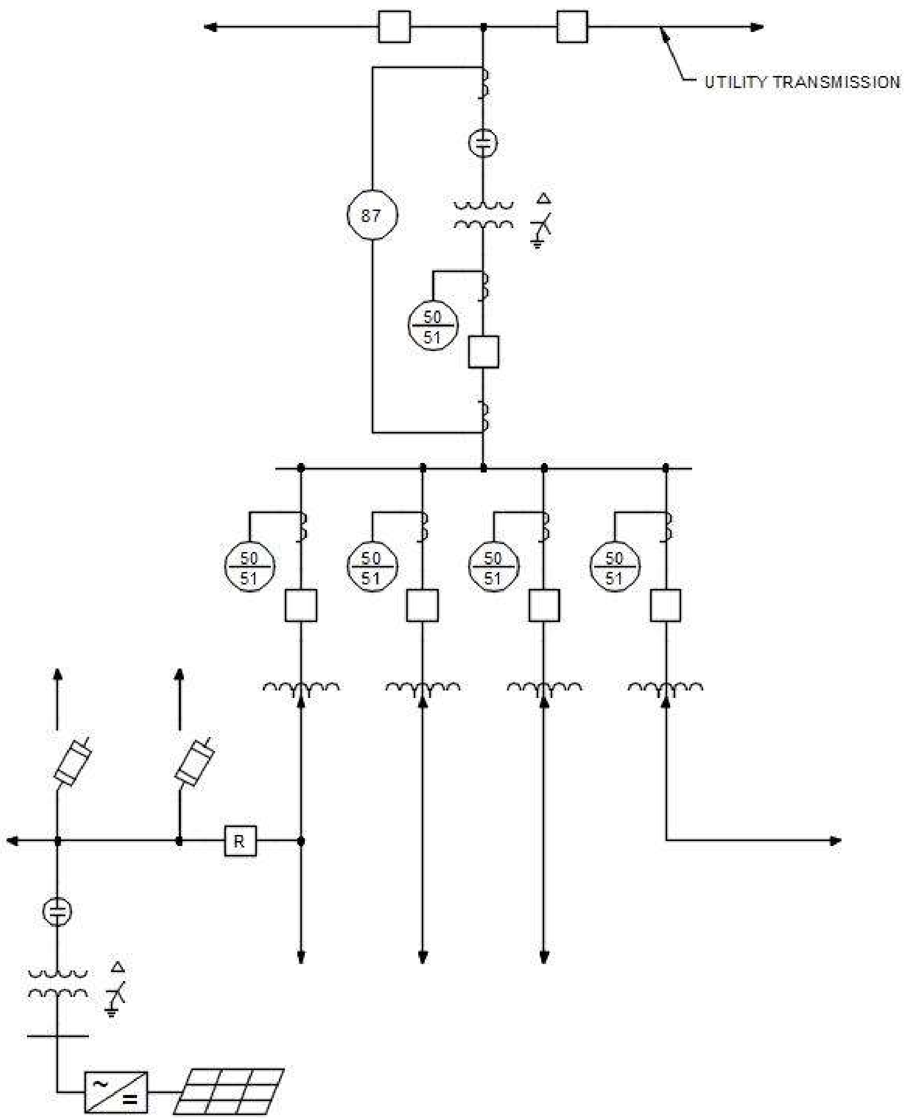


Figure 2 - Typical Distribution System with DER

The DER could be any type of energy source. Let's say it is a solar facility to be installed approximately 2 circuit-miles downline from the substation. The addition of the DER changes the performance of the system shown in Figure 1. Some typical system changes and resulting problems include:

- When operating, the DER will cause current to flow toward the utility substation. This current, flowing through the line impedance, will cause a voltage rise at the DER. The voltage rise caused by the DER in combination with the feeder voltage regulators can result in high voltages along the circuit, especially under light loads. Voltage regulator settings must be modified to accommodate DER operation.
- DER output can vary, moment to moment, causing changes in operating voltage. Voltage changes are particularly a concern for solar installations when clouds pass by, causing changes in solar energy. Such voltage changes can cause voltage regulators to "hunt", stepping down, then up, repeatedly.
- Voltage flicker can be a problem. Voltage flicker is the perception of the human eye to changes in luminance caused by voltage fluctuations.
- When the DER output exceeds the circuit loads, power can flow into the transmission system (reverse power flow). Reverse power flow is typically not acceptable by the power supplier.
- Available fault currents change with and without the DER in operation. A properly coordinated system may be affected by an increase in fault current or a change in fault current direction. Coordination changes may be required. Increase in fault current levels may also surpass the interrupting ratings of protective devices.
- Substation breakers and line reclosers can open and lock out while the DER continues to operate, causing a condition known as "islanding". Depending on the DER interconnection transformer winding connections, the primary lines during an island condition my no longer have a ground source. Electric systems should not be unintentionally islanded. System changes may be required to know if an island condition occurs and to disconnect the DER when islanding happens.
- During line-to-ground fault conditions, the voltage of one phase can rise relative to normal voltages, and result in over-voltage of line surge arrestors. Sixty hertz over-voltage of surge arresters can result in arrester failures.

3. PENETRATION RATIOS

Penetration Ratios are <u>preliminary analysis calculations</u> prepared to indicate performance expectations or design considerations for adding Distributed Generation (DG) to systems. Ratios are meant to be guides and used for distribution and subtransmission system impacts of DERs.

3.1 MINIMUM LOAD TO GENERATION RATIO (MLGR) [2]

This ratio is the annual minimum load on the power system divided by the aggregate DG capacity on the power system. This ratio is used to indicate system performance for Ground Fault Overvoltage Suppression and Islanding, discussed below.

3.1.1 GROUND FAULT OVERVOLTAGE SUPPRESSION ANALYSIS

The MLGR ratio is used for Ground Fault Overvoltage Suppression Analysis for systems that are not effectively grounded. Higher Penetration ratios indicate that system upgrades or adjustments will likely be needed to avoid power system issues.

Table 1 - MLGR: Ground Fault Overvoltage Suppression Analysis

Very Low Penetration (very low probability of any issues)	Moderate Penetration (low to minor probability of issues)	Higher Penetration (increased probability of serious issues)
>10 Synchronous Gen	10 to 5 Synchronous Gen	Less than 5 Synchronous Gen
>6 Inverters	6 to 3 Inverters	Less than 3 Inverters

3.1.2 ISLANDING ANALYSIS

The MLGR ratio is also used for Islanding Analysis. Higher penetration ratios indicate that there is an increased probability of undetected islanding and detailed islanding analysis should be performed.

Table 2 - MLGR: Islanding Analysis

Very Low Penetration (very low probability of any issues)	Moderate Penetration (low to minor probability of issues)	Higher Penetration (increased probability of serious issues)
>4	4 to 2	Less than 2

3.2 FAULT RATIO FACTOR (FRF) [2]

This ratio is the available fault current divided by the DER fault current at the point of interconnection (POI). This ratio is used to gauge whether there could be problems with existing overcurrent device coordination and ratings. For an FRF less than 20 – Higher Penetration, there is an increased probability of issues. Coordination of existing overcurrent settings with the addition of DER fault current should be reviewed.

Table 3 - Fault Ratio Factor

Very Low Penetration (very low probability of any issues)	Moderate Penetration (low to minor probability of issues)	Higher Penetration (increased probability of serious issues)
>100	100 to 20	Less than 20

3.3 STIFFNESS FACTOR[2]

This factor is the ratio of the available utility fault current divided by the DER rated output current at the POI. This factor is a good indicator of voltage influence. For a stiffness factor less than 50 for PV/Wind (< 25 Steady Source) – Higher Penetration, there is an increased probability of issues such as voltage rise and flicker. Load flow analysis should be performed to evaluate these issues.

Table 4 - Stiffness Factor

Very Low Penetration (very low probability of any issues)	Moderate Penetration (low to minor probability of issues)	Higher Penetration (increased probability of serious issues)
>100 PV/Wind	100 to 50 PV/Wind	Less than 50 PV/Wind
>50 Steady Source	50 to 25 Steady Source	Less than 25 Steady Source

3.4 DUKE ENERGY EVALUATION FACTORS

Duke Energy Progress/Duke Energy Carolinas have developed their own Circuit Stiffness Review (CSR) Screen & Evaluation procedure. If the proposed facility fails the CSR, a more rigorous/advanced study is required. The CSR is performed at two locations, the POI and at the substation.

3.4.1 POINT OF INTERCONNECTION FACTOR

POI Stiffness Factor (POI_SF) is the short circuit availability at the POI (MVA) without any DER contribution divided by the specific DER facility maximum export (MW). A POI Stiffness Factor of 25 or greater for the site is considered a pass.

3.4.2 SUBSTATION STIFFNESS FACTOR

Substation Stiffness Factor (SUB_SF) is the short circuit availability at the substation bus (MVA) without any DER contribution divided by the total facility maximum export connected beyond the substation (MW). A Substation Stiffness Factor of 25 or greater for the site is considered a pass.

4. LOAD FLOW ANALYSES

4.1 REVERSE POWER FLOW

Reverse power flow occurs when the output of the DER exceeds the distribution system loads. System loads should be reviewed to determine the annual maximum and minimum system loads. Full DER output and the system minimum load will determine whether reverse power flow can occur.

Reverse power flow is typically unacceptable to the power supplier. If the full load DER output is close to the system minimum load, the power supplier may require reverse power flow detection to prevent reverse power flow into the transmission system. A microprocessor relay can be used to detect a certain level of reverse power flow (ex: 85% of no load losses of the power transformer). When the reverse power flow exceeds the specified level, the relay will trip the high side protective device (breaker/circuit switcher, etc.). This causes a full outage of the substation distribution system.

4.2 REQUIRED VOLTAGE PROFILE

The output of a DER will cause a voltage rise on the electric system at the point of interconnection. Load flow analyses should be performed to determine whether the DER can be connected to the system while still maintaining adequate voltage levels.

The American National Standard Institute defines nominal voltage ratings in ANSI C84.1, American National Standard Voltage Ratings for Electric Power Systems, and Equipment (60 Hz). Range A applies under normal conditions.

Range "A" (normal conditions):

- Maximum allowable voltage – 126 volts.
- Voltage drop allowance for primary distribution line – 9 volts.
- Minimum primary service voltage – 117 volts.
- Voltage drop allowance for distribution transformer and secondary service – 3 volts.
- Minimum secondary service voltage (120-600 volt services) – 114 volts.

4.3 TRANSFORMER LTC / VOLTAGE REGULATOR INTERACTION

The voltage rise caused by the DER output can also cause unintended responses from existing system voltage regulators and transformer LTC. Voltage regulators and transformer LTC settings should be reviewed with the addition of DER. The DER should be analyzed with maximum and minimum system loads. Settings will need to be adjusted to meet Range “A” requirements under each of the following conditions:

- Maximum distribution system loads, no DER
- Maximum distribution system loads, with DER

- Minimum distribution system loads, no DER
- Minimum distribution system loads, with DER

Meeting the Range “A” requirements for each of the four scenarios can be difficult to achieve when a large DER is located at the end of a regulation zone. Below are some changes that can be made to the distribution system to improve the voltage.

- Line reconductoring
- Addition of switched capacitors
- Reducing maximum DER output
- Addition of line voltage regulators

5. VOLTAGE FLICKER

Flicker is defined by IEEE 1547 as:

> “The subjective impression of fluctuating luminance caused by voltage fluctuations”

IEEE Std 1453, *IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems*, adopts the international standard IEC 61000-4-15 limits for rapid changes in voltage, known as voltage flicker. IEC 61000 defines a precise method of measuring flicker and develops limits of measurement of complex flicker from an instrument known as a flickermeter. IEEE Std 1453 recommends limits of short term flicker, Pst, the standard output of the flickermeter over a 10 minute interval, and long term flicker, Plt, calculated using 12 consecutive Pst values over a two hour period, of 0.9 and 0.7 respectively.

IEEE Standard 141/519 has developed the following flicker tolerance curve that provides a borderline for visibility and a borderline of irritation.

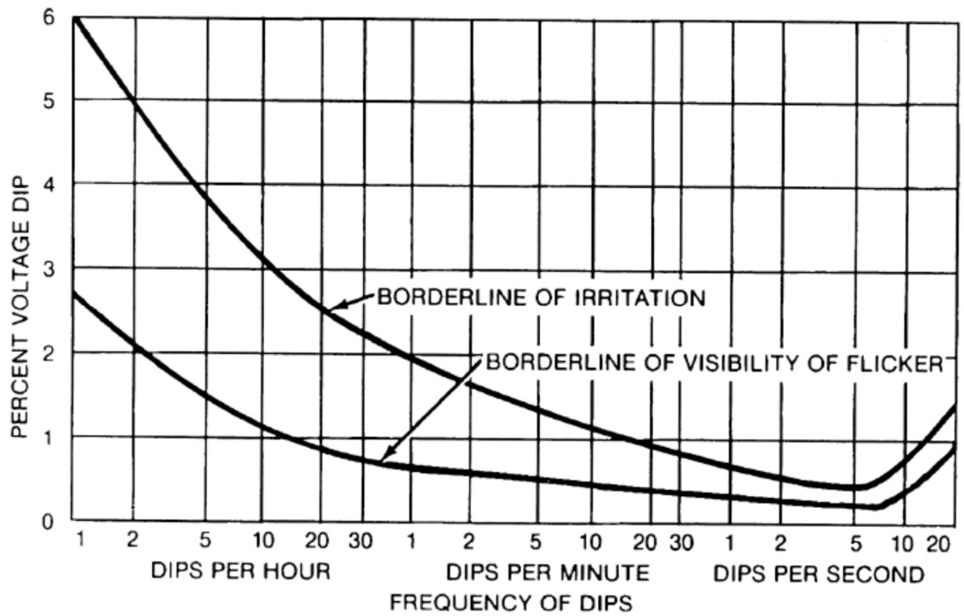


Figure 3 - Flicker Tolerance Curve

5.1 SOLAR DER FLICKER

The output of a Solar DER will fluctuate throughout the day with the cloud coverage over the solar panels, causing some voltage fluctuation at the point of interconnection. Voltage fluctuations can lead to fluctuating luminance or flicker.

The IEEE flicker tolerance curve, shown above, provides curves for the borderline of visibility of flicker and the borderline of irritation. Voltage dip magnitudes and frequency are compared below to these curves. The curves were developed based on rectangular voltage dips and are conservative when applied to the gradual increases and decreases in solar insolation produced by clouds. See figure below for example of rectangular voltage dips vs gradual voltage dips.

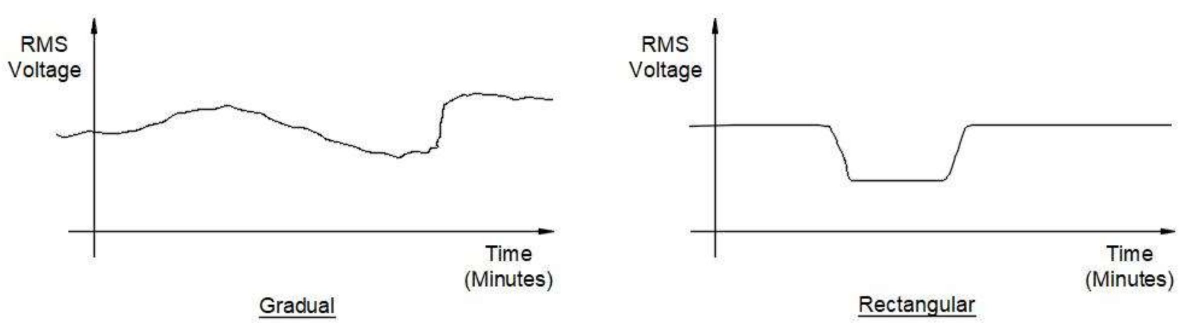


Figure 4 - Gradual vs Rectangular Voltage Change

UTEC obtained solar insolation curves for a cloudy summer day and a cloudy winter day for Elizabeth City, NC from CYME Distribution System Software. The solar insolation curves show the insolation (W/m^2) for a 24 hour period in the summer or winter. The solar insolation curves were then related to the results from a load flow analysis for approximately 100 different levels of solar output between 0 – 10 MW. The percent voltage change was calculated for every 5 minutes and the number of voltage dips per hour were recorded.

The following chart documents the voltage at the POI for 24 hours during a cloudy winter day.

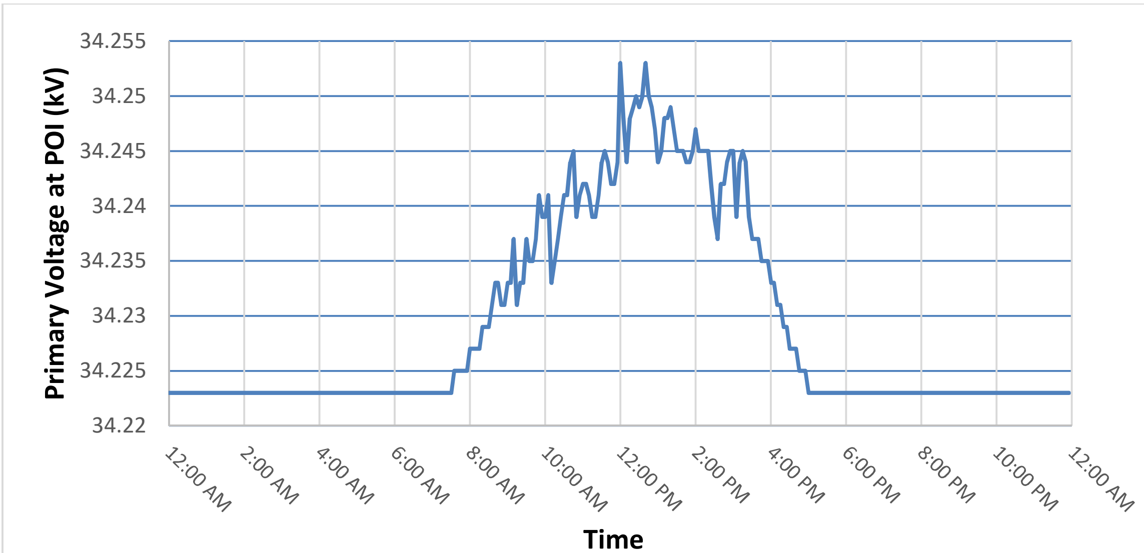


Figure 5 - Cloudy Winter Day

The maximum voltage change is 0.03%. The corresponding voltage dips per hour is 3. The maximum voltage dips per hour is 5, with a corresponding voltage change of 0.01%. Both of these results are far below the borderline of visibility on the flicker tolerance curve.

The following chart documents the voltage at the POI for 24 hours during a cloudy summer day.

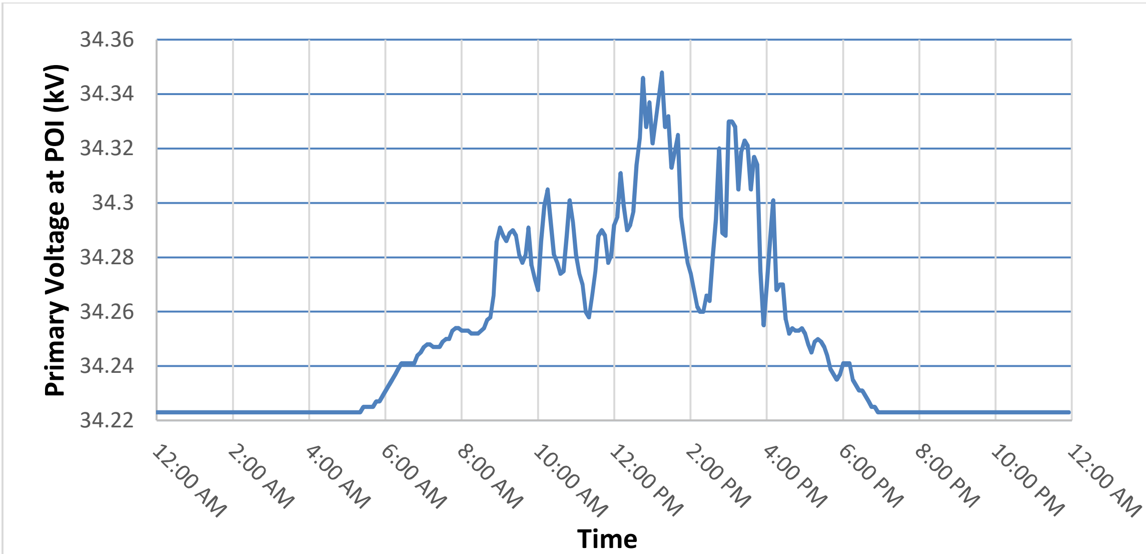


Figure 6 - Cloudy Summer Day

The maximum voltage change is 0.12%. The corresponding voltage dips per hour is 3. The maximum voltage dips per hour is 5, with a corresponding voltage change of 0.03%. Both of these results are far below the borderline of visibility on the flicker tolerance curve.

6. TRANSFORMER WINDING CONNECTIONS AND GROUNDING

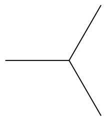
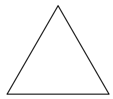
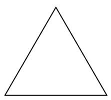
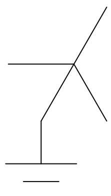
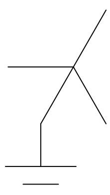
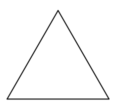
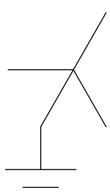
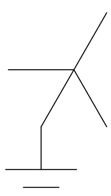
6.1 TRANSFORMER WINDING CONNECTIONS

DERs are typically connected to the distribution system using one of the five transformer connections shown below. The table[1] below identifies the advantages and disadvantages of each of the following transformer connections.

Table 5 - Transformer Winding Connections: Advantages/Disadvantages

Primary Connection	Secondary Connection	Disadvantages	Advantages
Δ	Δ	Can supply the feeder circuit from an ungrounded source after the substation	Provides no ground fault backfeed for a line fault. No ground current

[1] Table created from *Interconnection Transformer Winding Arrangement Implications Protection* by Wayne Hartmann, Beckwith Electric Co, Inc. and *Interconnect Protection of Dispersed Generators* by Charles J. Mozina, Beckwith Electric Co, Inc.

Primary Connection	Secondary Connection	Disadvantages	Advantages
		feeder breaker trips causing overvoltage. Does not supply a ground source for DER.	contribution from the substation for a fault on the secondary of the DER transformer.
		Can supply the feeder circuit from an ungrounded source after the substation feeder breaker trips causing overvoltage.	Provides no ground fault backfeed for a line fault. No ground current contribution from the substation for a fault on the secondary of the DER transformer. Supplies a ground source for DER.
		Provides an unwanted ground current source for line to ground faults. Does not supply a ground source for DER.	No ground current contribution from substation for a fault on the secondary of the DER transformer. No overvoltage for line ground fault.
		Provides an unwanted ground current source for line to ground faults. Allows substation relaying to respond to a ground fault on the secondary of the DER transformer.	No overvoltage for a line ground fault. Supplies a ground source for DER.

6.2 EFFECTIVE GROUNDING

“Effectively Grounded” is defined by IEEE 142, *Recommended Practice for Grounding of Industrial and Commercial Power Systems*, as:

> “Grounded through a sufficiently low impedance such that for all system conditions the ratio of zero-sequence reactance to positive-sequence reactance (X_0/X_1) is positive and less than 3, and the ratio of zero-sequence resistance to positive-sequence reactance (R_0/X_1) is positive and less than one.”

For ground fault conditions, “effective grounding” limits the L-G voltage on the unfaulted phases to roughly about 1.25-1.35 per unit of nominal during the fault. With an ungrounded source, the voltage could be as high as 1.82 per unit.[2]

7. FAULT CURRENT ANALYSIS

DERs can increase the available fault current on the system to which it is connected. Synchronous and induction machines generally contribute 4-10 times rated current to faults. Inverter based DERs typically only contribute 1-2 times rated current to faults and therefore are much less likely to cause fault current issues on the system.

When a DER is added to a system, the following fault current issues should be evaluated:

- Coordination of protective devices due to increased fault current. Fault current from a DER can also affect directional devices and impedance sensing devices.
- Interrupting capacity can be exceeded due to increased fault current. Electrical equipment ratings should be reviewed.
- Nuisance trips due to “backfeed” fault current.
- Distribution transformer rupture due to increased fault contribution.
- Temporary fault clearing by fast reclose of the substation breaker may not work due to the fault contribution from the DER.

8. ISLAND ANALYSIS

System problems that can result from a DER island:

- Downed conductors may continue to be energized by the DER after the substation breaker had tripped open.
- If the DER does not trip offline before the first reclose open interval of the substation breaker, the utility system will reclose into the live DER island, which can damage switchgear due to the DER island and substation being out of phase.
- DER Islanding may not maintain suitable power quality to customers.
- Overvoltages can occur, especially when the island is ungrounded, which can damage utility and customer equipment.

8.1 ISLANDING PROTECTION METHODS

8.1.1 PASSIVE RELAYING APPROACH

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[2] *Experiences in Integrating PV and Other DG to the Power System (Radial Distribution Systems)* by Philip Barker, Nova Energy Specialists, LLC

Use voltage and frequency relay functions to trip DER when conditions leave specified operating windows. Examples of parameters that can be used:

27	Undervoltage Relay
59	Overvoltage Relay
81O	Overfrequency Relay
81U	Underfrequency Relay

8.1.2 ACTIVE RELAYING APPROACH

Like passive relaying, an inverter watches for parameters to exceed specified thresholds, but the inverter also takes an active role in destabilizing the potential island using one of the following methods:

- Impedance Detection – The inverter modifies its output current to check for a corresponding change in voltage. This allows the inverter to measure the source impedance, which it compares to allowable values. If outside the specified range, the inverter will trip offline.
- Positive Feedback – When the inverter detects a shift in voltage or frequency, the inverter will attempt to "push" that parameter further out of range. If the inverter is able to push the parameter out of range, it will trip offline. These methods are known as the Sandia Frequency Shirt (SFS) and Sandia Voltage Shift (SVS).
- Combination of both Impedance Detection and Positive Feedback

8.1.3 COMMUNICATION LINK APPROACH

Use communication link between substation breakers and DER protection to trip the DER offline when the substation breakers trip. Direct Transfer Trip (DTT) is an example.

8.1.4 IEEE 1547 INVERTER REQUIREMENTS

For unintentional islanding where the DER continues to energize a portion of the system, the DER should detect the island and trip within 2 seconds of formation of the island according to IEEE Std 1547, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*. If the 2 second requirement is faster than the first reclose open interval on the substation breaker, the DER should cease to serve the system before the first reclose of the substation breakers. The 2 second requirement is not compatible with high speed utility reclosing.

9. CONCLUSIONS

Some key factors to consider when evaluating DER system impacts include:

- The size of the DER in comparison to the system load (MLGR, FRF, Stiffness factor).
- The aggregate DER on the system. The above ratios should include the total DER on the system being evaluated.
- Voltage regulation equipment and settings.
- Overcurrent device locations and settings. Inverter based DER will have less impact on fault current levels than synchronous/induction based DER.

With developers approaching electric utilities to connect DERs to the utility's electric system more frequently, it's important to review the potential impacts of the distributed generation. In many cases, DER projects can be screened using simple methods. This is especially true of small DER projects. However, with multiple DER projects on a single distribution line and as the size of DER projects continue to grow, the impacts on the utility system become more substantial, requiring more detailed analysis.