Protection & Control strategy for effectively interconnecting and islanding Distributed Energy Resources during grid disturbances

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***Abstract*: Distributed generation, mainly wind and solar farms, are rapidly increasing due to deregulated markets and the global trend to use more renewable sources of energy. These energy resources are directly connected to grid, and due to their large size may influence the behavior of the grid. Many grid codes now demand that the distributed generation connected to HV grids must withstand voltage dips to a certain percentage of nominal voltage and for a specific duration. Low-Voltage Ride-Through (LVRT) and Frequency Ride-Through (FRT) requirements are being specified by various Electric Power System (EPS) operators. On the other hand, when the utility power is disconnected from the grid due to clearance of a fault or on opening a circuit breaker for maintenance, it creates Loss of Mains (LOM) condition. In this condition the voltage nor the frequency is controlled by the utility supply. These DERs are not equipped with voltage and frequency control; therefore, the voltage magnitude of an islanded network may not be kept within the desired limits which causes undefined voltage magnitudes and frequency instability. Therefore DERs are to be equipped with islanding protection. This paper discusses application of simple to use LVRT protection and Voltage Vector Shift (VVS) protection using advanced algorithm for effectively interconnecting and islanding DERs during grid disturbances.**

Key words*: *Distributed Energy Resources; Interconnection protection; Low voltage ride through; Voltage vector shift; Islanding; Loss of Mains; Electric Power System

I. INTRODUCTION

Traditional power grid comprises of power generation located at remote end of the grid, far from the load centers. The power generated is subsequently transmitted over long distance transmission lines to the distribution substation, which in turn is distributed to the load centers through the distribution network. However, with the rapid inclusion of Distributed Energy Resources (DER), the power grid is changing fast. Several smaller wind and solar farms are getting added closer to the load centers, dramatically changing the power grid composition. Energy storage systems are also being added to support the grid during peak load conditions when the renewable generation may not be operating at its optimum capacity.

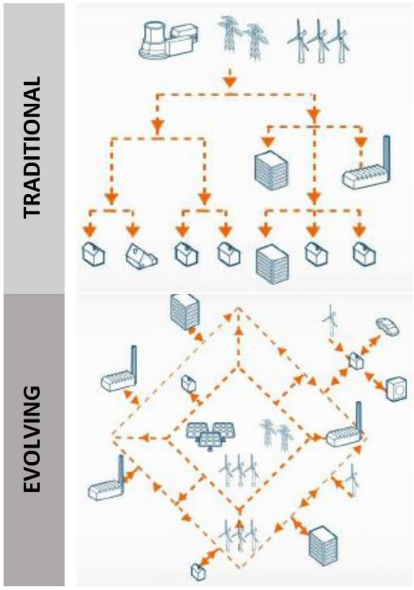


Figure 1: Changing power grid composition

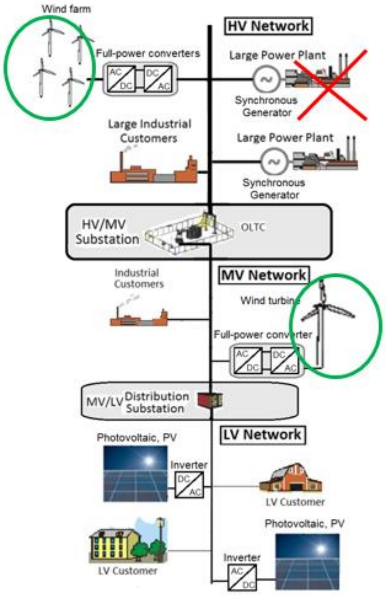


Figure 2: Traditional power plants are getting replaced by wind powered turbines and solar generation

The impact is that, large traditional power plants are replaced with the wind powered turbines on the HV network. Wind output variability and missing natural inertia (rotating mass) means large frequency and voltage variations are possible. Also, by adding more renewables into the MV network, it becomes even more important to prevent their disconnection, to support the whole system stability.

As the capacity of Distributed Energy Resources (DER) increase, they are connected directly to medium voltage networks. Until recent years it had been a practice by grid operators to disconnect the distributed power generator from the network in case of fault in the network. If there is a considerable loss in the power generation, it may affect the system's ability to recover. To ensure power system stability, various grid codes have revised their requirements, with DER requiring to contribute to network support. In case of network faults, the DER should not be immediately disconnected from the network. Instead, generating plants connected to the medium-voltage network is expected to participate in steady-state voltage control and dynamic network support. However, if the generators stay connected, it must be ensured that they do not take reactive power from the network because this may lead to collapse of the grid. The wind and solar farms are required to comply with stringent grid connection requirement, which was previously mandatory only for high capacity power plants. Many grid codes now demand that the distributed generation connected to HV grids must withstand voltage dips to a certain percentage of nominal voltage (down to 0% in some cases) and for a specific duration. Such requirements are known as Low-Voltage Ride-Through (LVRT) or Fault-Ride-Through.

The DERs vary in capacity from tens of kilowatts to tens of megawatts. They can supply power into the network as well as to the local loads. It is not common to connect generators directly to the distribution networks and thus the distributed generation can cause some challenges for the protection of distribution networks. From the protection point of view, one of the most challenging issue is islanding. Islanding is defined as a condition in which a distributed generation unit continues to supply power to a certain part of the distribution network when power from the larger utility main grid is no longer available after the opening of a circuit-breaker. Islanding is also referred to as Loss of Mains (LOM) or Loss of Grid (LOG). When LOM occur neither the voltage nor the frequency is controlled by the utility supply.

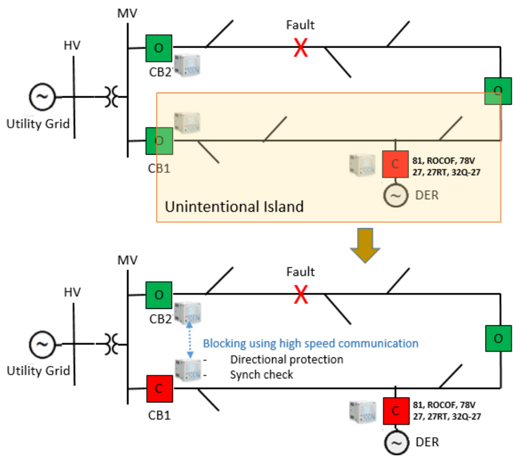


Figure 3: Unintentional islanding - Creation of a "healthy island"

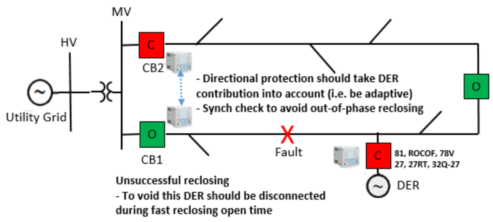


Figure 4: Unintentional islanding - Creation of a "faulty island"

These distributed generators are not equipped with voltage and frequency control; therefore, the voltage magnitude of an islanded network may not be kept within the desired limits which causes undefined voltage magnitudes and frequency instability. Islanding can occur due to circuit breaker tripping because of a fault in the network, or due to circuit breaker opening during maintenance. If the distributed generator continues its operation after the utility supply is disconnected, faults do not clear under certain conditions as the arc is charged by the distributed generators. Moreover, the distributed generators are incompatible with the current reclosing practices. During the reclosing sequence open time, the generators in the network tend to drift out of synchronism with the grid and reconnecting them without synchronizing may damage the generators introducing high currents and voltages in the neighboring network. To avoid these technical challenges, protection is needed to disconnect the distributed generation once it is electrically isolated from the main grid supply. Various techniques are used for detecting Loss of Mains. However, the protection function discussed here focuses on voltage vector shift (VVS) detection using advanced algorithm.

II. GRID CODE REQUIREMENTS

Grid Codes are technical specifications to be fulfilled by DERs which are connected to the Electric Power System (EPS), at the Point of Common Coupling (PCC). They typically specify the behavior of the generator under normal conditions as well as during disturbances. Traditionally this was required to be followed only by large conventional power plants. However, increasing amount or DERs now connected to the lower voltage levels have created the need to revise and upgrade Grid Codes.

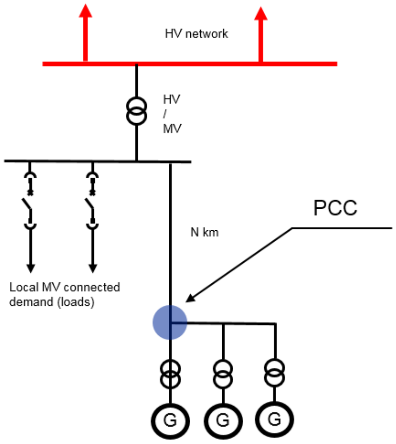
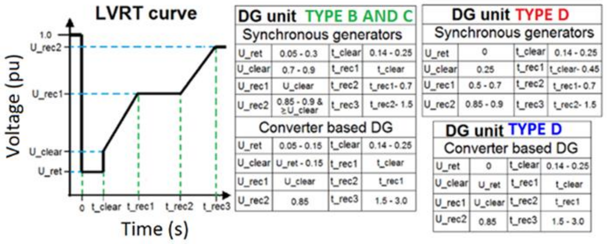


Figure 5: Typical DER connection to the grid

Grid Codes vary depending on country, type and size of generating unit. Several international workgroups are targeting to harmonize different national Grid Codes.

A. *Example from Europe:*



DG unit TYPE B AND C

Synchronous generators			
U_ret	0.05 - 0.3	t_clear	0.14 - 0.25
U_clear	0.7 - 0.9	t_rec1	t_clear
U_rec1	U_clear	t_rec2	t_rec1 - 0.7
U_rec2	0.85 - 0.9 & ≥U_clear	t_rec3	t_rec2 - 1.5

Converter based DG			
U_ret	0.05 - 0.15	t_clear	0.14 - 0.25
U_clear	U_ret - 0.15	t_rec1	t_clear
U_rec1	U_clear	t_rec2	t_rec1
U_rec2	0.85	t_rec3	1.5 - 3.0

DG unit TYPE D

Synchronous generators			
U_ret	0	t_clear	0.14 - 0.25
U_clear	0.25	t_rec1	t_clear - 0.45
U_rec1	0.5 - 0.7	t_rec2	t_rec1 - 0.7
U_rec2	0.85 - 0.9	t_rec3	t_rec2 - 1.5

DG unit TYPE D

Converter based DG			
U_ret	0	t_clear	0.14 - 0.25
U_clear	U_ret	t_rec1	t_clear
U_rec1	U_clear	t_rec2	t_rec1
U_rec2	0.85	t_rec3	1.5 - 3.0

Figure 6: LVRT requirement from ENTSO-E in Europe

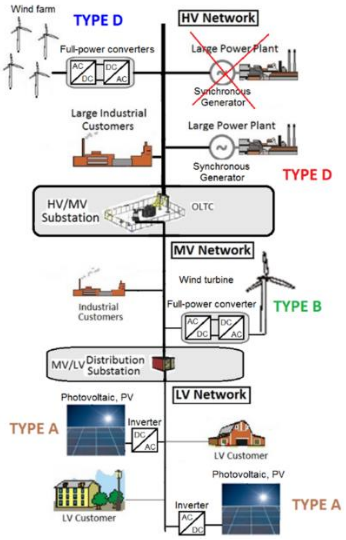


Figure 7: Example grid code showing how LVRT requirements vary for different DER types

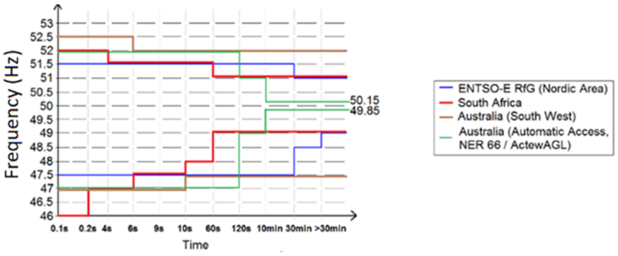


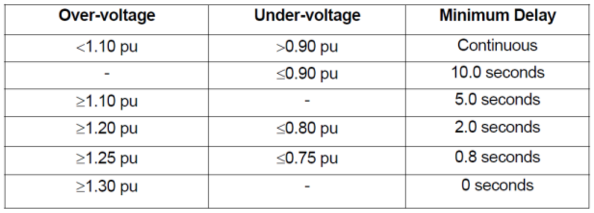
Figure 8: Example grid code showing how Frequency-Ride-Through requirements vary for different countries.

B. *Example from North America:*

TABLE I. OFF-NOMINAL FREQUENCY MINIMUM PERFORMANCE REQUIREMENT

Under-frequency Limit	Over-frequency Limit	Minimum Time
60.0-59.5 Hz	60.0-60.5 Hz	Continuous
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
Less than 56.4 Hz	Greater than 61.7 Hz	0 cycles

TABLE II. OFF-NOMINAL VOLTAGE MINIMUM PERFORMANCE REQUIREMENT



Over-voltage	Under-voltage	Minimum Delay
<1.10 pu	>0.90 pu	Continuous
-	≤0.90 pu	10.0 seconds
≥1.10 pu	-	5.0 seconds
≥1.20 pu	≤0.80 pu	2.0 seconds
≥1.25 pu	≤0.75 pu	0.8 seconds
≥1.30 pu	-	0 seconds

Above data is from *“60 kV to 500 kV Technical Interconnection Requirements for Power Generators”* by BC Transmission

C. IEEE Std 1547 - 2018 requirements

IEEE Std 1547 – 2018 (standard) provide detailed guidelines for Interconnection and Interoperability of DERs with associated Electric Power Systems (EPS). This standard addresses the critical need of having a single document of technical requirements for DER interconnection by providing uniform criteria and requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. Traditionally, utility EPS were not designed to accommodate active generation and storage at the distribution level. The standard provides comprehensive requirements for DER interconnection so that technologies and operational concepts to effectively integrate DER into existing EPS can be further developed to realize additional benefits and to avoid negative impacts on system reliability and safety. For the discussion of this paper, Category III DER from the standard has been referenced. Abnormal operating performance Category III is based on both Bulk Power System (BPS) stability/reliability and distribution system reliability/power quality needs where there is very high DER penetration.

C.1 Low-voltage ride-through performance:

For low-voltage ride-through and under voltage trip, the relevant voltage at any given time shall be the least magnitude of the individual applicable voltages relative to the corresponding nominal voltage. Voltage disturbances of any duration within continuous operation region shall not cause the DER to cease to energize and trip from the EPS. During temporary voltage disturbances, for which the applicable voltage on the phase that has the least voltage magnitude is less than the minimum of the continuous operation region, and within the corresponding voltage ranges and cumulative duration (minimum time), the DER is expected to ride-through and maintain synchronism with the EPS, not trip and shall restore output as specified. The tables below specify the DER response to abnormal voltage conditions, clearing times and ride-through requirements of Category III DER.

TABLE III. CATEGORY III DER RESPONSE TO ABNORMAL VOLTAGES

Shall trip condition	
Voltage (p.u. of nominal voltage)	**Clearing time (sec)**
0.88	21
0.5	2

TABLE IV. VOLTAGE RIDE-THROUGH REQUIREMENTS FOR CATEGORY III DER

Voltage range (p.u.)	**Operating mode**	**Min. ride-through time (sec)**	**Max. response time (sec)**
V > 1.20	Cease to energize	N/A	0.16
1.10 < V ≤ 1.20	Momentary cessation	12	0.083
0.88 ≤ V ≤ 1.10	Continuous operation	Infinite	N/A
0.70 ≤ V ≤ 0.88	Mandatory operation	20	N/A
0.50 ≤ V ≤ 0.70	Mandatory operation	10	N/A
V < 0.50	Momentary cessation	1	0.083

Cease to energize: Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.
Momentary cessation: Temporarily cease to energize an EPS, while connected to the EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.

Above requirements are plotted in the graph below:

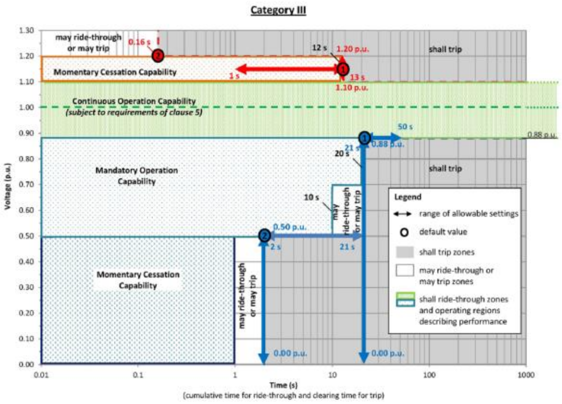


Figure 9: Response to abnormal voltages and voltage ride-through requirements of Category III DER

Similar operating conditions are specified for Category I & II DER as well. Category I & II has a slope characteristic at some of the operating points.

C.2 Frequency ride through requirement:

The graph below specifies the frequency ride through requirement of Category I, II and III DER as per IEE 1547-2018 standard.

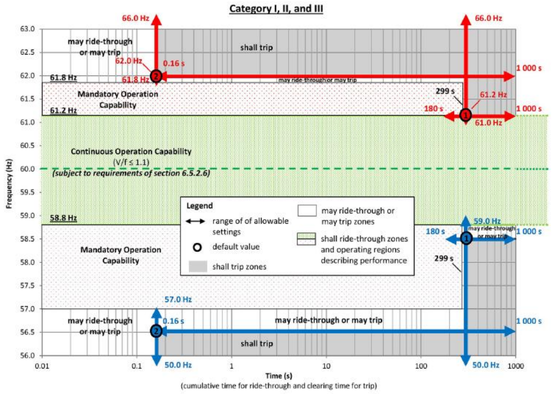


Figure 10: Default response to abnormal frequencies and frequency ride-through requirements of Category I, II and III DER

The standard also specifies that appropriate means shall be implemented to help ensure that EPS automatic reclosing onto a circuit remaining energized by the DER does not expose the EPS to unacceptable stresses or disturbances due to differences in instantaneous voltage, phase angle, or frequency between the separated systems at the instant of the re-closure (e.g., out-of-phase reclosing).

C.3 Islanding requirements:

The standard covers possible islanding situations of a DER. While a DER is in operation it is possible that it enters islanding mode. Islanding of a DER can be unintentional or intentional. For an unintentional island in which the DER energizes a portion of the EPS through the PCC, the DER shall detect the island, cease to energize the EPS, and trip within 2 seconds of the formation of an island. False detection of an unintentional island that does not actually exist shall not justify noncompliance with ride-through requirements.

Intentional islands can be scheduled or unscheduled. Scheduled intentional islands are formed through DER operator or EPS operator manual action or other operating dispatch means (e.g., Energy Management System or Automatic Generator Control action) that trigger the transition from being in parallel and synchronized with the EPS, to operation as an islanded system. Reasons for forming a scheduled intentional island can include enhanced reliability, economic dispatch decisions for self-supply or import/export of power with or through the EPS, or pre-emptive EPS operator action to island ahead of inclement weather. Unscheduled intentional islands are formed autonomously from local detection of abnormal conditions at the interconnection with the EPS, and then automatic relay action that triggers switching action to isolate the intentional island rapidly from the EPS.

III. PROTECTION AND CONTROL STRATEGIES FOR DER INTERCONNECTION

A. Low-voltage ride-through protection (LVRT) - 27RT

The various grid codes discussed in the previous section specifies LVRT requirements to be met by the DER. Typically the voltage and operating time requirements can be achieved by utilizing several under voltage relays and timers. However, the engineering of such a scheme can become complex. Also, the grid code varies from region to region for different DER categories. Therefore, a simple to set, ready to use LVRT protection element is introduced here. The low-voltage ride-through protection function 27RT is principally a three-phase under voltage protection. It differs from the traditional three-phase under voltage protection 27 by allowing the grid operators to define its own LVRT curve for generators, as defined by local or national grid codes. The LVRT curve can be defined accurately according to the requirements by setting the appropriate time-voltage coordinates.

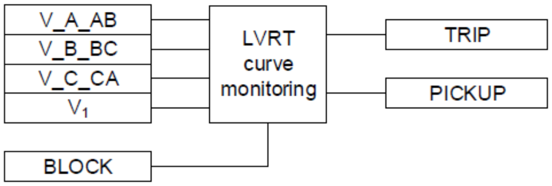


Figure 11: Low-voltage ride-through (27RT) protection element operation

LVRT curve monitoring starts with detection of under voltage as specified by the voltage pickup setting. Under voltage detection depends on *Voltage selection* setting. All selectable options are based on fundamental frequency components. Function uses phase-to-ground voltages when *Voltage selection* is set to “Highest Ph-to-E” or “Lowest Ph-to-E” and phase-to-phase voltages when *Voltage selection* is set to “Highest Ph-to-Ph” or “Lowest Ph-to-Ph”. When the *Voltage selection* setting is set to “Highest Ph-to-E”, “Lowest Ph-to-E”, “Highest Ph-to-Ph” or “Lowest Ph-to-Ph”, the measured three-phase voltages are compared phase-wise to the set *Voltage pickup value*. If the measured value is lower than the set *Voltage pickup value* setting in number of phases equal to that set *Num of pickup phases*, the PICKUP output is activated.

The setting options available for *Num of pickup phases* are “Exactly 1 of 3”, "Exactly 2 of 3", and “Exactly 3 of 3”, which are different from conventional setting options available in a normal under voltage relay. For example, when *Num of pickup phases* is set to "Exactly 2 of 3", any two voltages should drop below *Voltage pickup value* within one cycle to activate PICKUP. Even if more than two voltages drop below *Voltage pickup value*, PICKUP output is not activated. When the *Voltage selection* setting is “Positive Seq”, the positive-sequence component is compared with the set *Voltage pickup value*. If it is lower than the set *Voltage pickup value*, the PICKUP output is activated. Once PICKUP is activated, the function monitors the behavior of the voltage defined by *Voltage selection setting* with the defined LVRT curve. When defined voltage enters the operating area, the TRIP output is activated instantaneously.

If a drop-off situation occurs, that is, voltage restores above *Voltage pickup value*, before TRIP is activated, the function does not reset until maximum recovery time under consideration has elapsed i.e., PICKUP output remains active. LVRT curve is defined using time-voltage settings coordinates. The settings available are *Recovery time 1…Recovery time 10* and *Voltage level 1…Voltage level 10*. The number of coordinates required to define a LVRT curve is set by *Active coordinate* settings. When *Recovery time 1* is set to non-zero value, it results into horizontal characteristics from point of fault till *Recovery time 1*. It is necessary to set the coordinate points correctly to avoid misoperation. For example, setting for *Recovery time 2* should be greater than *Recovery time 1*as illustrated in example Curve A below. *Recovery time 1…Recovery time 10* are the respective time setting from the point of fault.

Typical LVRT behavior of a DER and setting examples:

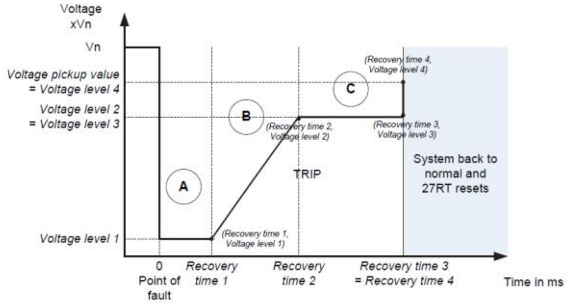


Figure 12: A typical ride-through voltage capability of generating unit

Typical LVRT behavior of a DER can be divided into three areas according to the variation in voltage over time.

1. At the time of system faults, the magnitude of the voltage may dip to *Voltage level 1* for a period defined by *Recovery time 1*. The generating unit must remain connected to the network during such condition. This boundary defines area A.
2. Area B defines the linear growth recovery voltage level from *Voltage level 1* to *Voltage level 2* during the period *Recovery time 1* to *Recovery time 2*.
3. Area C is the zone where voltage stabilizes. *Voltage level 3* is defined to same value as *Voltage level 2*. The system should remain above this voltage for a period *Recovery time 2* to *Recovery time 3*.
4. The system restores to a normal state and function resets when the voltage is equal or greater than *Voltage level 4* after *Recovery time 4* elapses.

When the voltage at the point of common coupling is above the LVRT curve, the generation unit must remain connected, and must be disconnected only if the voltage takes value below the curve.

Figure 13 describes operation of 27RT protection function set to operate with *Num of pickup phases* set to “Exactly 2 of 3” and *Voltage selection* as “Lowest Ph-to-Ph” voltage.

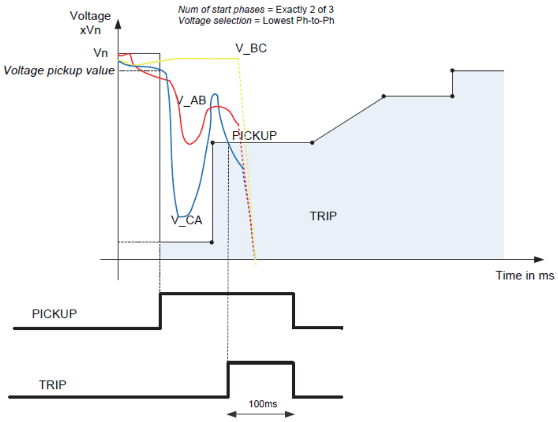


Figure 13: Typical example of 27RT operation

The LVRT element picks up at the instant of 2 out of 3 voltages fall below the Voltage pickup setting. The function trips instantaneously when the lowest Ph-Ph voltage enter the trip region.

Two LVRT example curves with corresponding 27RT settings are illustrated below.

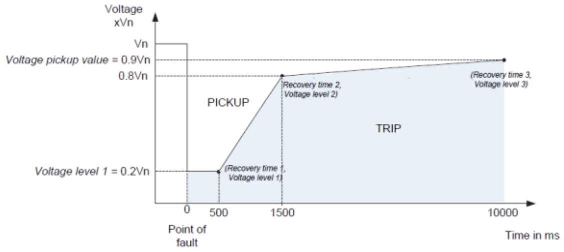


Figure 14: Low voltage ride through example curve A

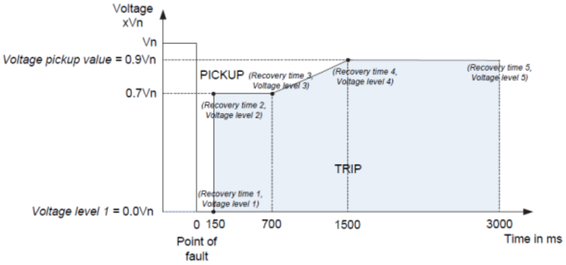


Figure 15: Low voltage ride through example curve B

TABLE V: 27RT SETTINGS FOR LVRT CURVE

27RT Settings	Curve A	Curve B
Voltage pick-up value	0.9*Un	0.9*Un
Active coordinates	3	5
Voltage level 1	0.2 * Un	0 * Un
Recovery time 1	1500ms	150ms
Voltage level 2	0.8 * Un	0.7 * Un
Recovery time 2	1000ms	150ms
Voltage level 3	0.9 * Un	0.7 * Un
Recovery time 3	10000ms	700ms
Voltage level 4	-	0.9 * Un
Recovery time 4	-	1500ms
Voltage level 5	-	0.9 * Un
Recovery time 5	-	3000ms

B. Directional reactive power under voltage protection (32Q-27)

Another protection element applied for interconnection protection is Directional reactive power under voltage protection. 32Q-27 element is used at the grid connection point as stipulated by various grid codes to prevent voltage collapse of the grid due to network faults. 32Q-27 measures phase voltages and current at the PCC. The DER is disconnected from the network with a specific time delay if all phase voltages decrease and remain at or below the specified limit and if reactive power is simultaneously consumed i.e., under-excitation operation. This element is not discussed in detail since it is not the focus of this paper.

C. Voltage vector shift protection (78V)

C.1 Common challenges of traditional passive islanding detection methods:

One of the key protection functionalities in the emerging gird will be reliable detection of islanding. Although the new grid codes from different regions require LVRT capability from DER and possibly allow island operation, there is still a need to reliably detect the islanding situation to make the correct operations. Islanding detection is required to initiate strategies like changing the setting group of a DER interconnection relay or changing the control principles and parameters of a DER unit. It may be recalled that IEEE 1547-2018 specifies that a DER should cease to energize the EPS, and trip within 2 seconds of the formation of an island. Here again, reliable detection of islanding situation is important to comply with the standard.

One of main challenges with traditional passive local islanding detection methods is its ability to selectively operate in the non-detection zone (NDZ) near power balance situation. The NDZ may result in unwanted DER trips due to other network events (nuisance tripping). If the number of DER units in the distribution network increases, as is expected in the future, the risk of power balance situations will also increase. Therefore, the risk of possible operation in the NDZ of the traditional passive islanding detection methods also will increase. In addition, voltage and frequency elements will be used more often for defining the distributed generators LVRT and FRT requirements in the grid codes to enable utility grid stability supporting functionalities from DER units.

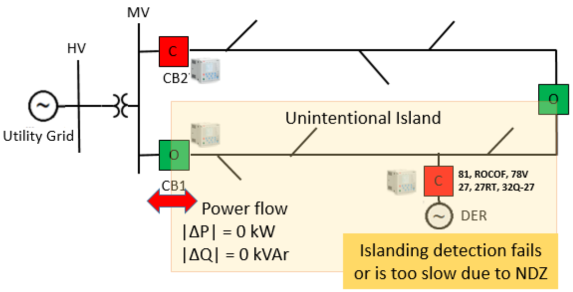


Figure 16: Non-detection zone (NDZ) near a power balance

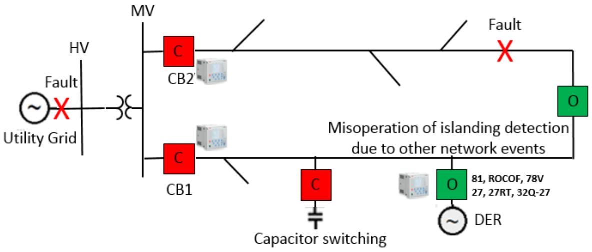


Figure 17: Unwanted tripping due to other network events

Different techniques are available for the Islanding detection. Combining communication with local detection method together improves the sensitivity & selectivity of operation. However, an effective “stand-alone” local passive method by using advanced vector shift algorithm is now available which is discussed below.

C.2 Basic vector shift principle

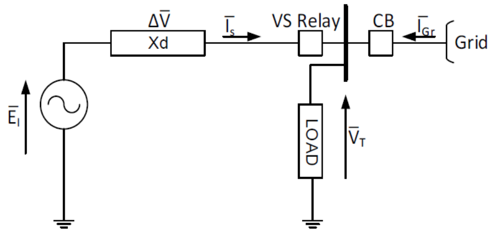


Figure 18: Equivalent circuit of a synchronous generator operating in parallel with the grid

When the generator current I_s passes through the generator reactance X_d, there is a voltage difference ΔV between the terminal voltage V_T and the generator internal voltage E_I (Figure 18). Consequently, there is a displacement angle θ between the terminal voltage and generator internal voltage. The phasor diagram is shown in Figure 19(a). After the circuit breaker opens, the system consisting of the generator and load becomes islanded. At this instant, the synchronous generator begins to feed a larger (or smaller) load because the current I_{Gr} provided by the grid is interrupted. Due to this, the angular difference between V_T and E_I is suddenly increased (or decreased) and the terminal voltage phasor changes its position as shown in Figure 19(b). The sudden vector shift due to islanding can also be seen in the voltage waveform in Figure 19(c).

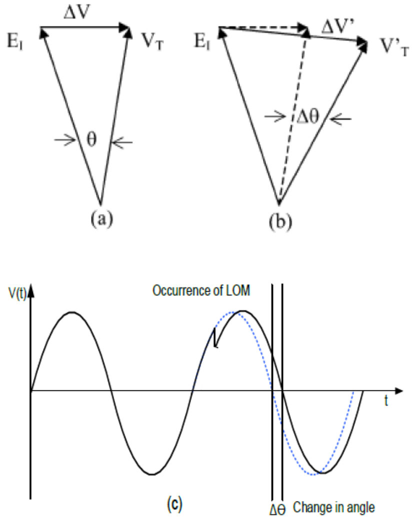


Figure 19: Internal and terminal voltage phasors: (a) before islanding (b) after islanding (c) vector shift in voltage waveform

C.3 Advanced vector shift algorithm

The advanced algorithm uses all three phase voltages or a positive sequence voltage for the vector shift detection. It is designed not to cause nuisance tripping of DER due to other network disturbances. The algorithm considers the behavior of voltage and frequency simultaneously, adapts to steady-state frequency variations and has time-dependent correlation checks between phase voltages (when all three-phase voltage are used). The algorithm adaptively corrects the measured vector shift angle based on the steady-state frequency variation. This makes the algorithm immune to steady-state frequency variations. The vector shift algorithm is blocked, when any of the measured voltages drop below or increase above the threshold values.

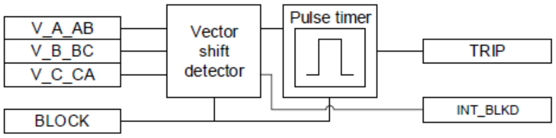


Figure 20: Voltage vector shift (78V) operation

The Vector shift detector measures the duration of each cycle of the voltage signal. The duration of the present cycle is compared to the previous cycle, considered as reference. When the main is lost, a sudden change is seen in the cycle length, if loading of the generator changes suddenly and power mismatch or unbalance (generation vs. load) in the islanded part of the network is large enough. The cycle shifts with time, that is, the frequency may not change but a vector shift is seen in phase as shown in Figure 19(c). This step change is measured in degrees for each voltage signal defined by the *Phase supervision* setting. The *Phase supervision* setting determines which voltage is used for detecting vector shift. The available *Phase supervision* options are “All” and “Positive sequence”. If the calculated value of $\Delta\theta$ exceeds the set *Pickup value* setting for all the defined phases, the module sends an enabling signal to start the Pulse timer. Once the Pulse timer is activated, it activates the TRIP output.

The *Voltage selection* setting is used to select whether the available voltage signal is phase-to-ground or phase-to-phase voltage. If the magnitude of the voltage level of any of the monitored voltage signal, defined by the *Phase supervision* setting, drops below *Under Volt Blk value* or exceeds *Over Volt Blk value*, the calculation of vector shift is disabled and the INT_BLKD output is activated. The function is blocked and LOWAMPL_BLKD is activated, if the measured frequency deviates ±5% from the nominal value.

The vector shift detection protects synchronous generator from damaging due to islanding or loss-of-mains. To detect loss-of-mains with vector shift function, the generator should aim to export or import at least 5 to10% of the generated power to the grid, to guarantee detectable change in loading after islanding or loss-of-mains. Extensive tests have been conducted [3] to ascertain that the VVS function operates securely under different loading conditions. However, if the active and reactive power generated by the distributed generation unit is nearly balanced (for example, if the power mismatch or unbalance is less than 5 - 10%) with the active and reactive power consumed by loads, a large enough voltage phase shift may not occur which can be detected by the vector shift algorithm. This means that the vector shift algorithm has a small non-detection-zone (NDZ) which is also dependent on the type of generator, load, network and pickup or trip value of the vector shift algorithm. Therefore, there is still a need for developing alternate passive methods for detecting the islanding mode without NDZ. It has also been ascertained that the VVS function is stable during other network events like capacitor switching, switching of very large loads in weak network or connection of parallel transformer at HV/MV substation, in which the voltage magnitude is not changed considerably unlike in faults. Nevertheless, if extremely sensitive settings are used, the vector shift algorithm can potentially cause misoperation during other network events. This aspect should be taken into consideration while setting this function.

C.4 Multi-criteria Loss of Mains protection:

Apart from vector shift, there are other passive techniques which are used for detecting Loss of Mains. Some of these passive techniques are over/under voltage, over/under frequency, rate of change of frequency, voltage unbalance, and rate of change of power. These passive methods use voltage and frequency to identify Loss of Mains. The performance of these methods depends on the power mismatch between local generation and load. The advantage of all these methods is that, they are simple and cost effective, but the disadvantage is that each method has its own NDZ. To overcome this problem, it is recommended to combine different criteria for detecting Loss of Mains where two or more protection functions run in parallel. When all criteria are fulfilled to indicate Loss of Mains, an alarm or a trip is generated. Vector shift and rate of change of frequency are two parallel criteria that can be used for effectively detecting islanding condition.

IV. CONCLUSION

With the rapid increase of DER integration into HV and MV grid, these DERs play a huge role in system stability more than ever before. Various countries have already revised or are in the process of updating their Grid Code to specify DER capability and performance during grid disturbances. These requirements are vital to maintain the voltage and frequency stability of the grid in the event of grid disturbances. LVRT is one of these requirements which are to be complied by the DER operators. The simple, ready to use LVRT protection element provides selectable settings which will help the DER operator to define the LVRT curve to comply with the local Grid Code.

The grid code also specifies a competing requirement of disconnecting a DER in an islanding condition. An effective strategy for detecting islanding situation is therefore very important. The new advanced vector shift protection algorithm improves the dependability and stability of the voltage vector shift-based islanding detection. The VVS algorithm can adaptively correct the measured vector shift angle based on the steady-state frequency variations. This makes the algorithm immune to steady-state frequency variations. Tests conducted in [3] verifies that the advanced VVS algorithm successfully detects the islanding condition during small and large power unbalances. In addition, the algorithm can reduce DER unit nuisance tripping because it is stable during various network disturbances like faults, capacitor switching and connection of parallel transformer, if the settings are not very sensitive. Although the advanced VVS algorithm guarantees fast and reliable islanding detection in nearly all operational conditions when the DER is running in parallel with the utility grid, certain cases may still cause misoperation. However, if the power unbalance before islanding is very small and the detected vector shift angle is therefore also small, the function may not operate. This means that the vector shift algorithm, like many traditional passive islanding detection methods, still has a NDZ near a power balance situation. Potential method to deal with this NDZ issue could be by using the multi-criteria based passive islanding detection method as detailed in [1] or use of active MV network management detailed in [2].

V. REFERENCES

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VII. BIOGRAPHY

Joemoan (Joe) Xavier received his bachelor’s degree with a Distinction in Electrical & Electronics Engineering from Mahatma Gandhi University. In 1993, Joe started his career as a protection engineer. He joined ABB India in 1996 and served over 13 years before joining ABB in the United States. During these years Joe has been involved with Application & Marketing of Protection, Automation, MV, HV products and systems of ABB. Currently Joe is the West Region Technical Manager for ABB Distribution Protection & Automation division based out of Camas WA. He is focused on applying modern intelligent relays and automation products to build solutions for Utility and Industrial customers to enhance safety and efficiency of operations. Joe has authored and presented several technical papers on Protection & Automation applications and is an active member of IEEE - Power System Relaying & Control Committee.