Impact of Renewable Energy Sources on the Protection of MV Distribution Networks

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ABSTRACT

Given the speed of renewable energy sources (RES) introduction in modern grids, there is an increasing need to characterize the challenges it imposes on protection systems and find suitable solutions to maintain reliability.

This paper describes the results obtained in tasks 3.4 and 3.5 of the FLEXIGRID h2020 project, in which a study of the impact of converter-based generation on feeder relays installed in MV primary substations and on fault passage indicators installed in MV secondary substations was done.

A benchmark MV distribution grid was defined and modelled in RTDS, including high penetration with PV and wind type III and IV generators. Different test cases were defined, with different fault locations, fault types, fault resistances, load conditions and neutral connections. The Spanish Grid Code was considered when defining the control of the mentioned converter-based generators. In this work, the results of testing with the traditional units and algorithms are shown, it describes the new units and algorithms implemented in the feeder relay and fault passage indicator; in the final section it exposes the results obtained with the improved protection functions and finally, the challenges faced in setting calculations and coordination for a pilot test on a real substation with RES contribution.

Keywords: protection relays; fault identification; renewable energy; wind turbine; photovoltaic generator; incremental quantities, directional, distance

1. INTRODUCTION

The need for a more sustainable energy model and for a reduction in greenhouse gas emissions has greatly increased the use of renewable energy sources (RES) in MV and HV grids, such as wind and solar. These generators behave very differently than traditional synchronous or asynchronous generators during fault conditions, due to their coupling through power electronics-based inverters. This affects the reliability of protective relays use nowadays, as they were designed for the conventional generation.

This paper analyses the impact of these RES on MV feeder protection and fault passage indicators, focusing on the most important protection units used such as overcurrent and directional ones. It also studies the impact on the phase selector, as this unit is used in certain configurations by the directional units. The summary of the problems detected in the mentioned units using traditional algorithms were:

- Lack of dependability of phase overcurrent units during phase-phase or three-phase faults
- Erroneous operation of directional units (phase, positive-sequence, negative-sequence),

- Unreliable operation of phase selector based on currents.

In order to solve the mentioned problems, new units and algorithms were implemented in both the feeder relays and fault passage indicators to solve the problems detected:

- Use of distance units to increase the dependability during phase-phase and three-phase faults. The mentioned distance units included an improvement in the compensation of the apparent resistance, using appropriate line reactance polarizations.
- Use of a directional unit that combines positive-sequence voltages with phase currents or a dynamic combination of positive-sequence and negative-sequence directional units.
- Implementation of a phase-selector based on voltage components.
- Use of voltage restrained overcurrent units.

2. TEST DESCRIPTION

RES can be classified according to different criteria, however, regarding its fault response, two groups can be identified. Fully interfaced generators include Type IV wind turbines and Photovoltaic power plants (PV). On the other hand, Partially Interfaced generators include the Type III wind turbine. In this study, non-directional and directional overcurrent protection algorithms were tested under fault contribution from a Type III wind generator and a Photovoltaic power plant to account for both types of RES.

2.1 Grid Model Description

A benchmark distribution grid model has been developed to evaluate protection relay performance under high penetration renewable scenarios. It is based on a real distribution grid and its electrical parameters were obtained from a real system (cables, transformers, short circuit power). Figure 1 shows a scheme of this grid model.

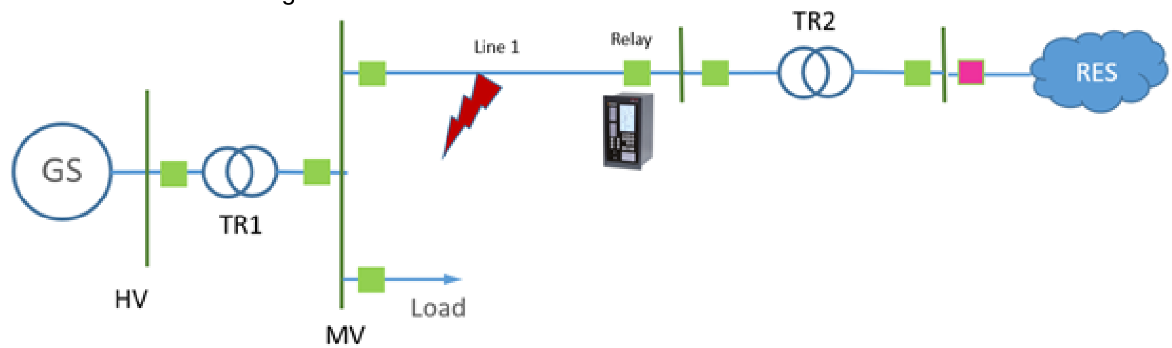

Figure 1. Benchmark distribution grid used to analyze relay performance

The benchmark grid, which has been implemented in RSCAD software, is composed of a 55 kV HV external network and a 12 kV distribution grid. HV network is represented using a Thevenin equivalent. Two renewable technologies connected to the distribution grid are considered to carry out the studies: PV and a type III wind turbine. Overhead lines are used to connect renewable technologies to the distribution grid. Finally, an underground distribution grid topology is also considered to perform the analysis.

For analysing the relay behaviour, the following fault types have been carried out:

- Single line to ground fault
- Line to line fault
- Double line to ground fault
- Three-phase fault

These faults were applied at different locations of Line 1 of the Benchmark Model, in which 100% of the fault seen by the relay is contributed by the RES. Furthermore, two different renewable penetration levels have been used in to cover a wider view of the results:

- Rated power=3 MW
- Rated power=11 MW

As it is mentioned before, RES is connected to the electric grid by a power electronic interface. The RES control response under fault conditions is regulated by the specific grid code required by system operators. Most actual grid codes require reactive current injection as a method of voltage support under voltage sags for inverter-based generators. In the event of a symmetrical fault, current Spanish grid code [1], requires the supply of positive sequence current (I1), while for unsymmetrical faults, positive and negative sequence current (I2) injection, proportional to the change in voltage level is required according to Figure 2.

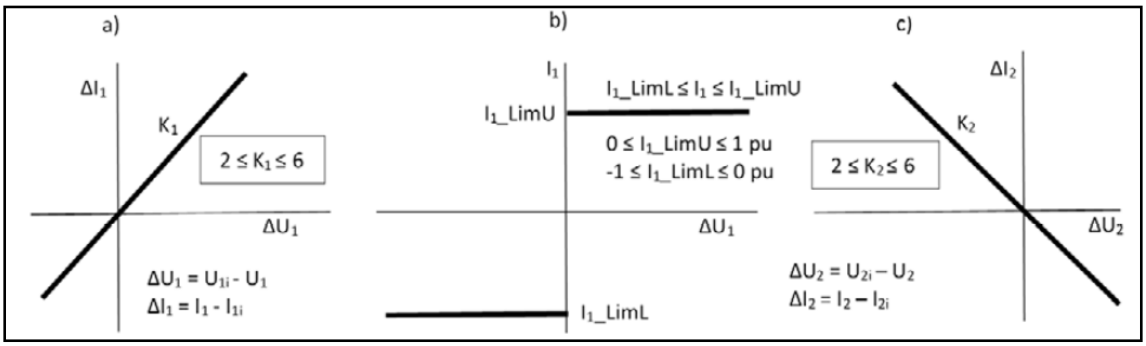

Figure 2. a) Injection/consumption of additional positive sequence reactive current (∆I1) depending on positive sequence voltage deviation (∆U1); b) Total reactive current (I1) injection/consumption limitation; c) Injection/ consumption of additional positive sequence reactive current (∆I1) depending on positive sequence voltage deviation (∆U1). [1]

Where all values are in per unit system referred to nominal magnitudes and following abbreviations are used: K1 refers to the direct sequence current control gain, K2 to the inverse sequence current control gain, LimU to the upper current injection limit and LimL the lower current injection limit.

During a fault, while injecting current, once the inverter limits are reached, a priority must be assigned to each of the active and reactive component of the current in both sequences, so the control system decides which component injection to restrain. However, grid code does not give a specific limitation. For the controls implemented in the models for this work, following priority was assigned: First, positive sequence reactive current, then negative sequence reactive current and at last, positive sequence active current, while negative sequence active power is supressed.

3. RESULTS OF SIMULATION USING PROTECTION ALGORITHMS

A summary of the results obtained from the testing of different protection functions is presented in this section. Results from faults applied at 50% of Line 1 of the Benchmark Model, in which 100% of the fault seen by the relay is contributed by the RES, are shown.

3.1 Overcurrent Protection

In this section, a summary of the results obtained from the testing of non-directional and directional overcurrent protection is presented. Figure 3 shows the fault current contribution measured by the protection relay during an AB fault applied at 50% of the line and PV is connected. As it is shown in the figure, after a short initial transient, fault current contribution remains close to the values prior to the fault. Consequently, the setting criteria used to set the pick-up of phase time overcurrent elements, which are based on synchronous generation current contribution, are not suitable in scenarios where fault contribution only comes from these renewable resources.

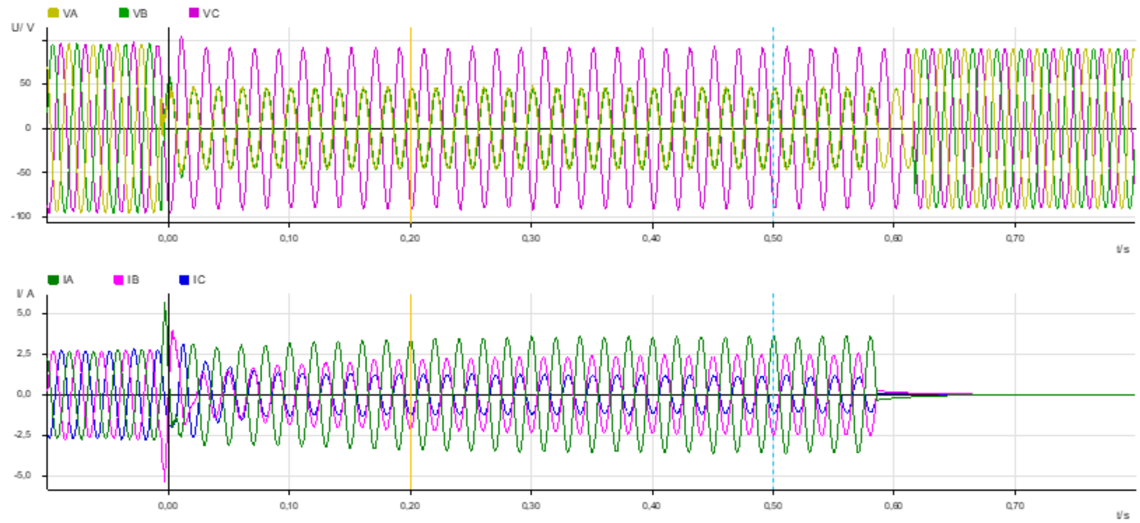

Figure 3. 11 MW PV: fault current contribution when AB fault is applied.

On the other hand, Figure 4 shows the fault current measured by the relay when the Type III generator is connected. Type III generators are partially interfaced by the inverter and most of the power is transferred directly from the induction machine stator. Therefore, under fault, the response is more similar to the response of a synchronous generators in terms of current magnitude, at least during the first cycles of the fault, allowing phase overcurrent protection to trip in this case.

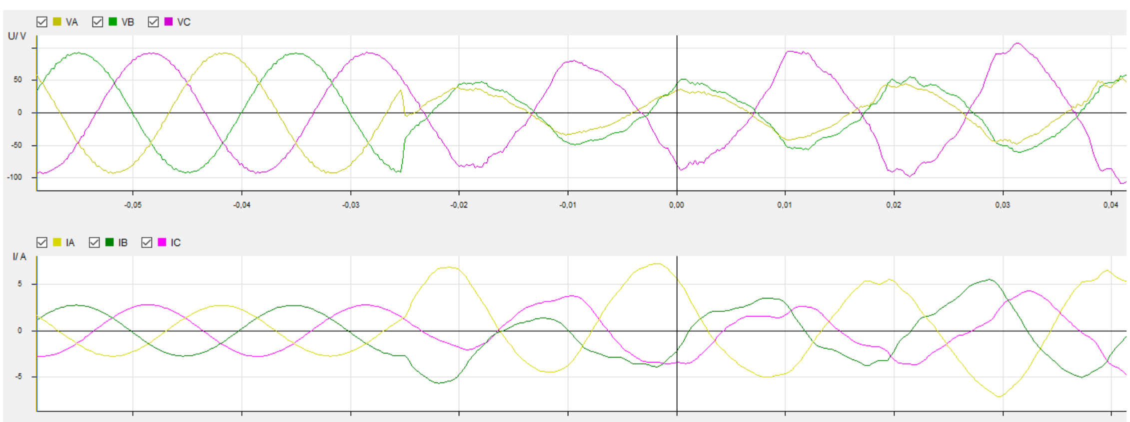

Figure 4 AB fault response from Type III WT

3.2 Faulted Phase Selector

Typical current based Faulted Phase Selector makes use of the angular difference between I2 and $I1_f = I1 - I1_{pf}$, as shown in Figure 5. Where $I1_f$ represents pure fault positive sequence current, which is calculated by subtracting pre-fault current, $I1_{pf}$ to measured fault current I1, with the aim of removing the load impact on the angle calculation.

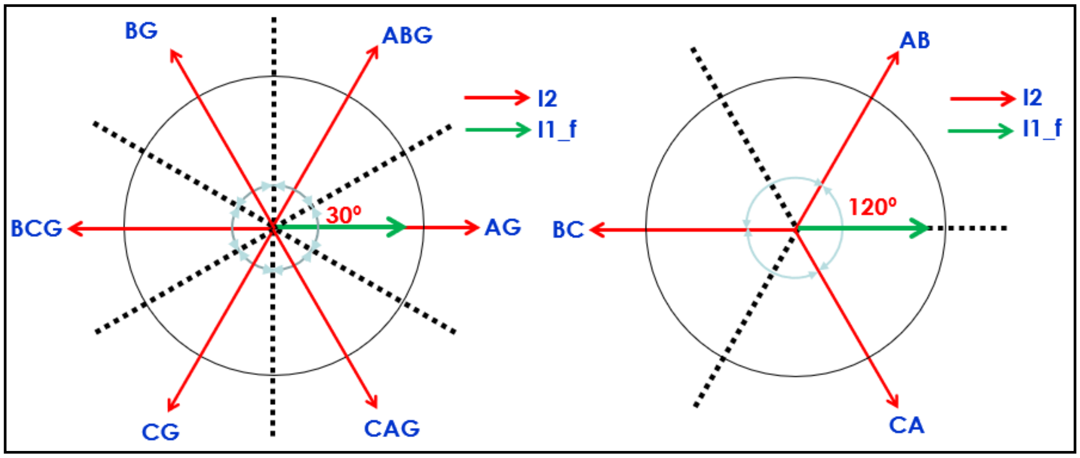

Figure 5 Negative to pure fault positive sequence current angular relationship for different fault types.

Fault type	Type III WT	PV
AG	✓	✓
AB	✗	✓
ABG	✗	✗
ABC	✗	✗

Table 1 shows a summary of the results obtained using the Phase Selection algorithm (PH_SEL) described in Figure 5, when fault current comes from Type III wind turbine and PV. As summarized in Table 1 the current based Phase Selection algorithm might fail under the influence of 100% inverter-based sources.

Fault type	Type III WT	PV
AG	✓	✓
AB	✗	✓
ABG	✗	✗
ABC	✗	✗

Table 1 Faulted Phase Selector results using current based phase fault selector

Examples of the current based PH_SEL failing to recognize the correct fault type can be seen in Figure 6 and

Figure *7* for two different fault types (ABG and AB) and two different RES generators (PV and Type III WT).

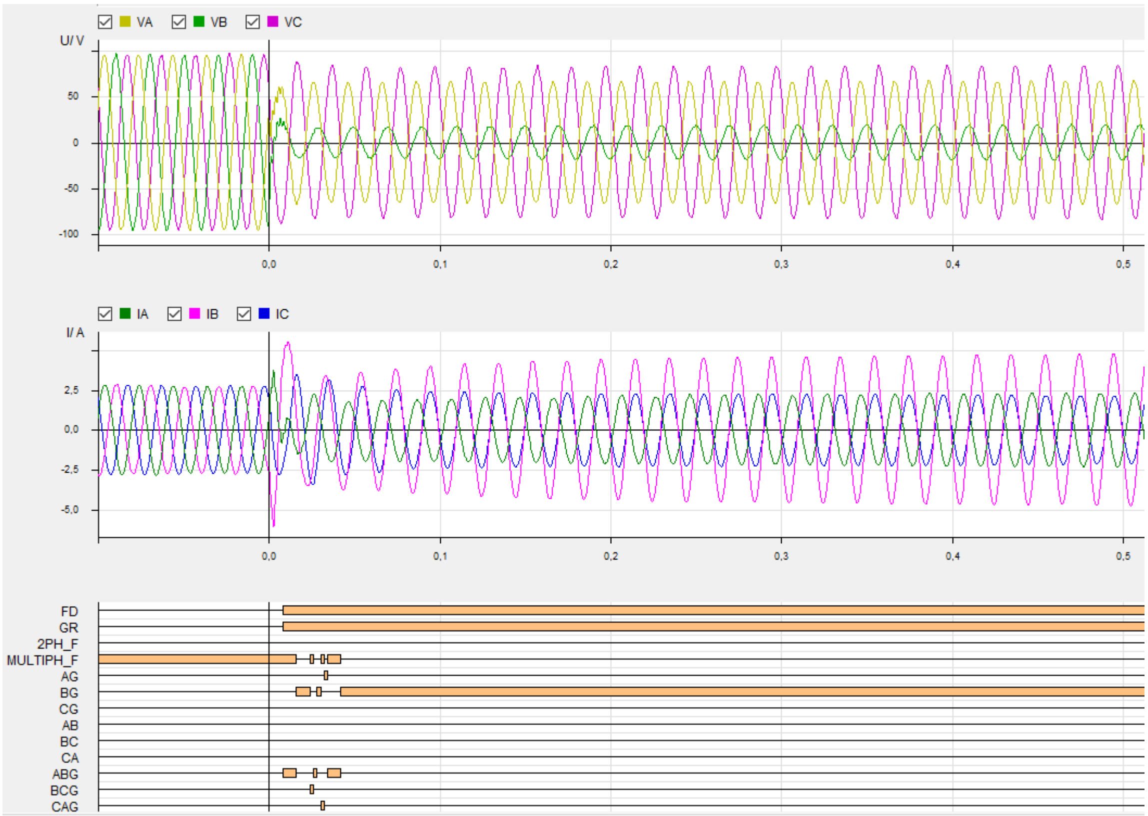

Figure 6. Phase fault selector when ABG fault is applied and feed by PV model.

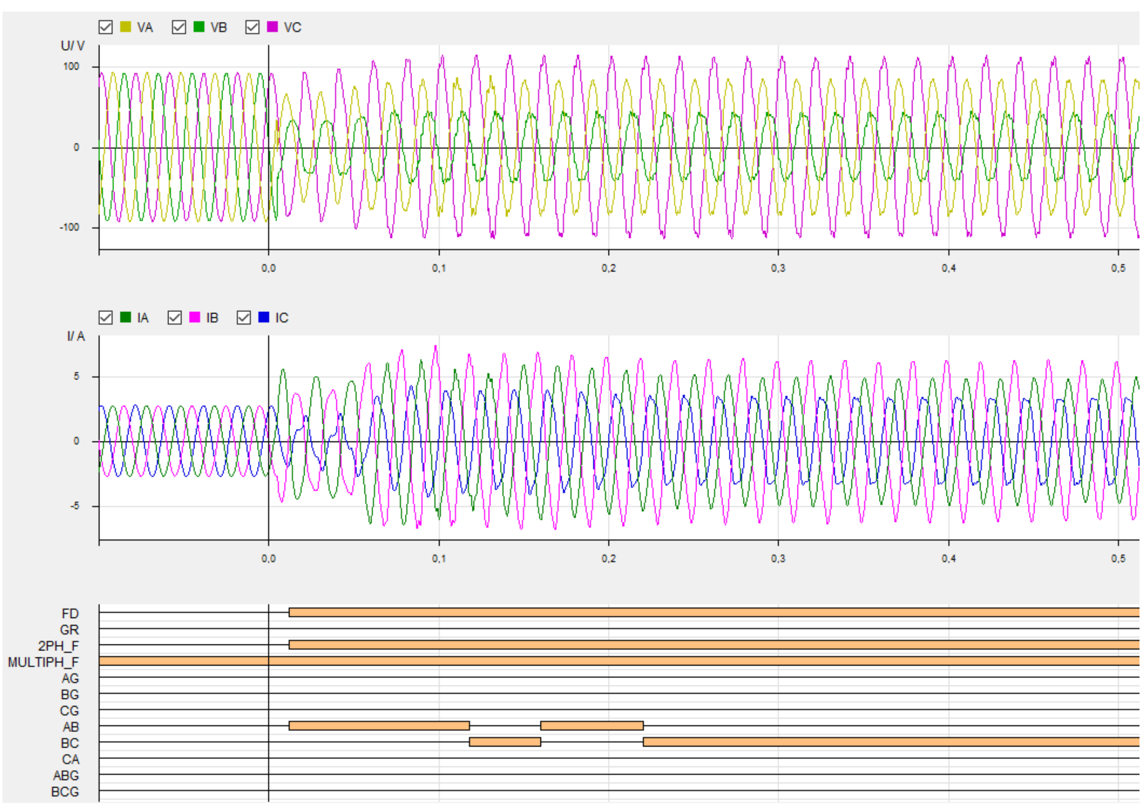

Figure 7 Phase fault selector when AB fault is applied and feed by Type III WT

As mentioned on [2], angle relationships between voltage sequence components, given by the fault type, are expected to be translated to currents sequence components on a synchronous generator fault current contribution since the positive (ZS1) and negative (ZS2) source impedance they represent has a predominantly reactive nature, namely, a 90º angle. However, in case of RES current contribution, these angular relationships might not be translated due to three different conditions impacting these source impedances angle:

1. On legacy PV parks, that do not comply with a modern grid code that require I2 injection, I2 might not even be present, making ZS2 angle untrustworthy at all.
2. On PV plants that do supply inductive I2, due to inverter current capacity limitations, pure fault ZS1 angle will differ from 90º, making angular relationship between $I1_f$ and I2 incorrect.
3. On Type III wind turbines, $I1_f$ and I2 angle might also not be trustworthy due to the influence of the rotor in fault current supply if crowbar protection is active. Under this condition, rotor ZS1, seen by stator side is divided by rotor to stator slip (s), while ZS2 is divided by 2-s, altering both impedances in different magnitude. When the crowbar does not operate a type III generator behaves like a type IV one.

3.3 Directional Overcurrent Units

For grounded grids, Neutral / ground directional unit (67N) behaves correctly for ground faults. However, in the case of an ungrounded grid, following directional units were put to test, which, in summary, showed different behaviors to different RES faut contribution.

- <u>Positive-sequence directional unit (67P)</u>: showed a correct behavior except when the crowbar of the Type III wind generator operates.
- <u>Negative-sequence directional unit (67Q)</u>: behaves correctly only when the generator injects reactive negative-sequence current
- <u>67P/PH (67P21)</u>: uses the positive-sequence voltage and the phase currents. It behaves correctly for any fault condition

4. CONCLUSIONS FROM TEST RESULTS

This section summarizes the main conclusions obtained from the tests performed on protection relay. These conclusions are listed below:

- Fault current contribution from renewable generators based on power electronics is limited during fault conditions. Therefore, it might be necessary to enhance the algorithm to detect fault current magnitude with the aim of detecting pick-up current. Furthermore, the unpredictable nature of generation units and demand can involve coordination problems. Then, settings definition of overcurrent protection is an important task.
- The criteria used for directional detection must be reviewed to consider the influence of renewable resources. These criteria used to detect directionality varies between the different relay manufacturers and the selected settings (positive sequence, negative sequence, phase current, etc..). Depending on the selected criteria the relay could not detect the fault direction correctly due to the waveform of the current injected by the PE-based renewable sources.
- Phase fault detector element has a wrong operation when unbalanced faults are present in the electric grid.

Based on these conclusions, the following enhancements were proposed to maintain reliability in fault scenarios with high RES.

1. Use of distance units to increase the dependability during phase-phase and three-phase faults. The mentioned distance units included an improvement in the compensation of the apparent resistance, using appropriate line reactance polarizations.
2. Use of a directional unit that combines positive-sequence voltages with phase currents or a dynamic combination of positive-sequence and negative-sequence directional units.
3. Implementation of a phase-selector based on voltage components.

The next section describes the implemented enhancements.

5. ENHANCEMENTS IMPLEMENTED ON ZIV RELAY

Enhancements mentioned in following subsections are to be implemented on a ZIV Feeder Protection Relay model IRF. Also, a ZIV Fault Passage Indicator, model TCA, in which voltage restrained overcurrent units are to be implemented as solution in this case, given the complexity of adding a Distance Unit on this type of equipment. Both protection IEDs are to be used as a prototype for the pilot testing on a real medium voltage distribution network.

5.1 Voltage Based Phase Selection Algorithm

As previously described on [2], in presence of RES, angular relationships between voltage sequence components might not be trustworthy since the impedance represented by those sources might differ from a totally inductive one due to the control strategy used for current injection during a fault. Therefore, an algorithm for faulted phase selection based on the angular relationship between voltage sequence components was developed, defining:

$$\varphi_{V21} = \varphi_{V2} - \varphi_{V1} \quad (1)$$

$$\varphi_{V20} = \varphi_{V2} - \varphi_{V0} \quad (2)$$

where:

φ_{V21}: Angle difference between negative and positive sequence voltage components.
φ_{V20}: Angle difference between negative and zero sequence voltage components.

On [2], the impact that ground fault resistance, negative sequence non-homogeneity, zero sequence non-homogeneity and non-homogeneity between zero and negative sequence might have on the previously mentioned angular relationships was described. Phase-to-phase (RPH) fault resistance also showed a major impact on φ_{V21} angular relationship. Therefore, a counterclockwise angular displacement was applied to φ_{V21} sector. Following angular zones for selecting fault type were established.

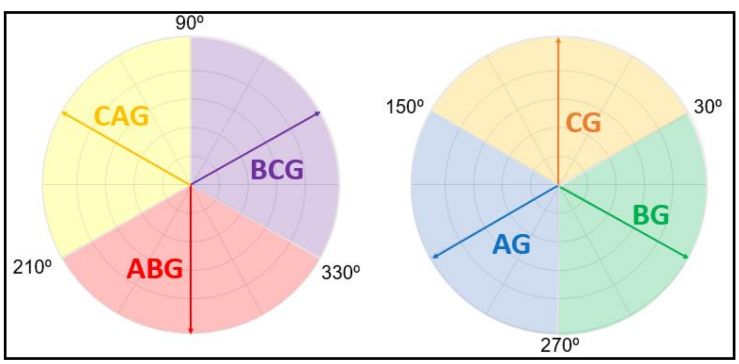

Figure 8 φV21 Angular zones for faulted phase selector.

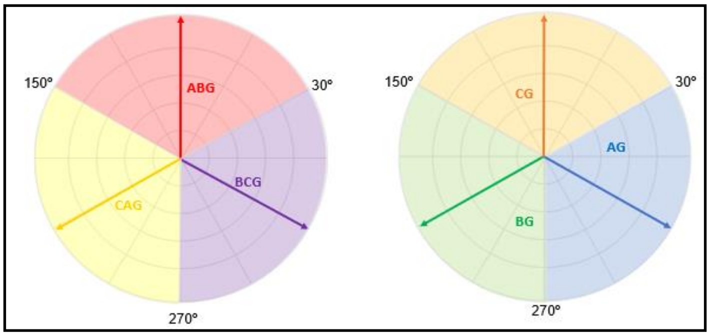

Figure 9 φV20 Angular relationships for faulted phase selection.

Once φ_{V21} and are φV_{20} calculated. The following logic is applied to determine fault type:

AG: $150^o \leq \varphi_{V21} < 270^o$ & $270^o \leq \varphi_{V20} < 30^o$

BG: $270^o \leq \varphi_{V21} < 30^o$ & $150^o \leq \varphi_{V20} < 270^o$

CG: $30^o \leq \varphi_{V21} < 150^o$ & $30^o \leq \varphi_{V20} < 150^o$

ABG: $210^o \leq \varphi_{V21} < 330^o$ & $30^o \leq \varphi_{V20} < 150^o$

BCG: $330^o \leq \varphi_{V21} < 90^o$ & $270^o \leq \varphi_{V20} < 30^o$

CAG: $90^o \leq \varphi_{V21} < 210^o$ & $150^o \leq \varphi_{V20} < 270^o$

To improve reliability on the proposed faulted phase selector, if non on the angular relationship combinations are meet, the activation of distance AG, BG, CG or ABG, CAG or BCG units in conjunction with φ_{V20} are used to determine faulted phase, differentiating single- or two-phase faults. Zero sequence voltage component is used to discriminate ground faults.

5.2 Distance Protection and Compensation of Apparent Fault Resistance

As noted in section 3.1, a lack of sustained phase fault current brought by inverter limitations makes phase current an unreliable magnitude for fault detection. Therefore, impedance protection, which also takes in account voltage variation for fault detection becomes a suitable solution, since it can detect lower short circuit current faults. Furthermore, distance protection does not depend on fault current level, which might change, since impedance to the fault does not depend on the source impedance. However, adequations need to be made to traditional distance protection to ensure a correct operation in presence of RES given the results obtained using traditional protection shown in Table 2.

Fault type	Type III WT	PV
AG	✗	✓
AB	✗	✗
ABG	✗	✗
ABC	✗	✗

Table 2 Typical 21 Protection Results

As it has been described on [2], the angle of ZS1 that represents a RES is modified by the current injection control during a fault. As a result, a non-homogeneity is introduced in the system, which might deviate the apparent fault resistance angle and cause maloperation of the distance quadrilateral reactance line and cause an overreach or underreach effect. Therefore, a real time compensation of the source impedance angle was introduced in the calculation of the polarization phasor used for the reactance line calculation.

Since different polarization phasors are suitable for different fault conditions, an algorithm has been used to dynamically change the calculation of the reactance line polarization phasor according to the situation, in case sufficient I2 injection is observed or not, compensation is required or a pole open is detected for example.

5.3 Voltage Dependent Overcurrent Units

The lack of sustained short circuit current brings difficulties for timed overcurrent units to act on a RES feed fault. Therefore, voltage dependent phase overcurrent units (50V/51V) are proposed since they are more dependable than standard phase overcurrent units when the short circuit current is closer or even lower than the load current. The higher dependability is provided by the decrease of the pick-up value when a voltage decrease is detected. There are two types of units available in the ZIV protection relay family.

- **Voltage controlled units:** the phase overcurrent units only pick-up if undervoltage units activate. As the sensibility problems occur during ungrounded faults, the undervoltage units operate with phase-phase voltage as shown in Table 3**¡Error! No se encuentra el origen de la referencia.**. [3]

Phase Current	Control Voltage	Sequence Voltage
IA	UAB	UAC
IB	UBC	UBA
IC	UCA	UCB

Table 3 Phase current and control voltages (ABC Phase Sequence).

- **Voltage restraint units:** the pick-up value is dependent on the phase-phase voltage value, following the characteristic shown in Figure 10.

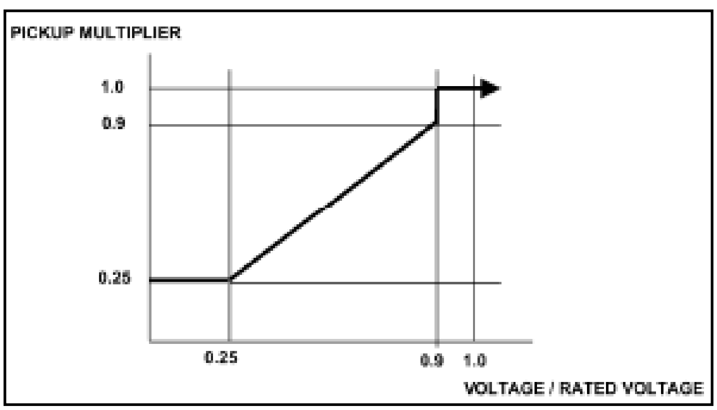

Figure 10 Pick-up value vs Measured phase-phase voltage [3]

Voltage restrained units are selected for this application to adequately detect phase to phase faults.

6. RESULTS OF SIMULATION USING PROPOSED ALGORITHMS

Voltage-Based Faulted Phase Selector Algorithm and Distance Unit with Apparent Fault Resistance Compensation solutions proposed showed correct results when exposed to fault records from PV, and Type III wind turbine models with and without negative sequence current (I2) injection.

Faults were simulated at 50% of Line 1 of the Benchmark Model varying source type.

	Type III WT		PV	
	Fault resistance R=0.1 Ω		Fault resistance R=0.1Ω	
Unit	**PH_SEL**	**21**	**PH_SEL**	**21**
AG	✓	✓	✓	✓
AB	✓	✓	✓	✓
ABG	✓	✓	✓	✓
ABC	✓	✓	✓	✓

Table 4 Voltage Based Faulted Phase Selector and 21 Unit with Apparent Fault Resistance Compensation Results

The impact of compensating the local source angle, is graphically shown under impedance locus simulation for an AG fault at 50% of the line, feed by the PV model. In this case1.5 Ohms of fault resistance were added to show more clearly the effect of a varying source impedance on the apparent fault resistance

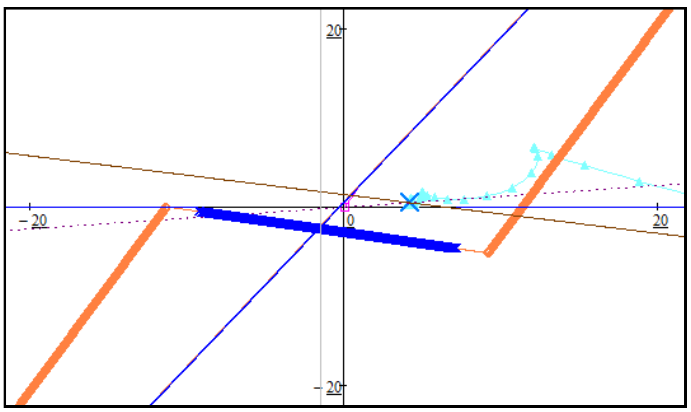

Figure 11 Quadrilateral distance characteristic for a AG fault feed by Type III model.

On Figure 11, quadrilateral distance characteristic is shown. Directional line is shown in bold blue, while resistive limiters are shown in orange. Blue line represents reactance line calculated using I2 as polarization phasor. The angle of the reactance line, in this case, due to the varying local source impedance, does not match with the angle of the apparent fault resistance shown in brown, completely rotating reactance line angle and making 21 protection inaccurate, since an external fault would also be asserted as internal. On the other hand, in Figure 12, the calculation of the reactance line angle polarization phasor takes in account the compensation factor K2 described on [2], therefore reactance line follows more closely the angle of the apparent resistance, covering the fault impedance locus into the operating characteristic, while an external fault would not be reached.

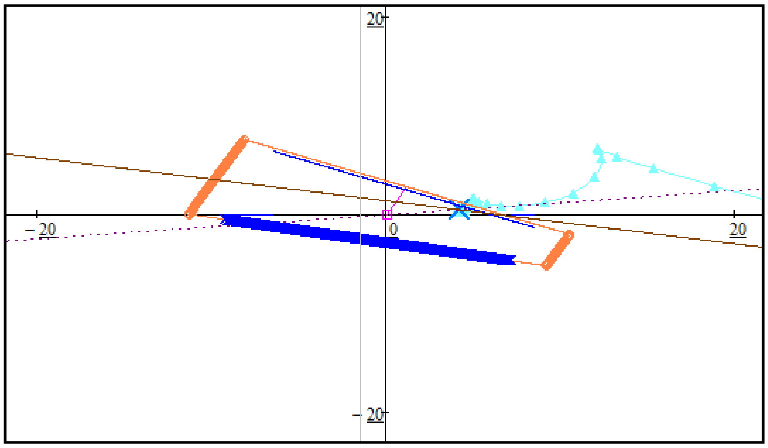

Figure 12 Quadrilateral distance characteristic for an AG fault feed by Type III model. Compensated.

Regarding solution proposed for directional units. he use of the Distance Directional showed a correct identification of fault direction for both Generator Types.

7. PILOT TEST SETTINGS CALCULATIONS

Once the enhancements to protection algorithms have been validated through real time simulation, the ZIV IRF relay prototype is used for a pilot test on a real substation on a MV ungrounded distribution network (Figure 13), in which there is variable RES contribution on the 130kV side of the primary substation. In this figure, the location of the prototype is shown along with an additional PV Plant feeding the secondary substation. Settings applied to ensure correct operation of the prototype are explained in this section.

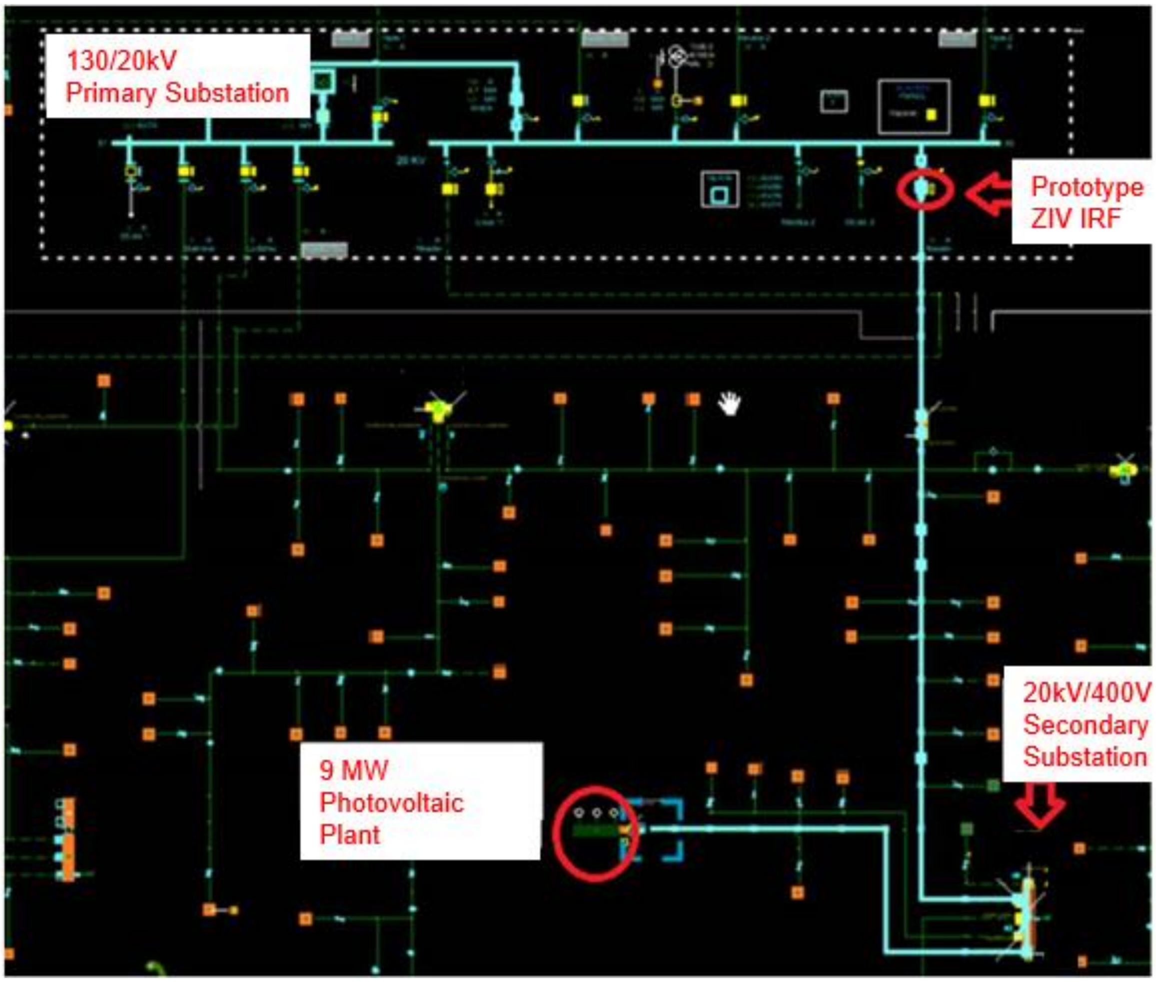

Figure 13 MV Network Layout

7.1 50/51V

The use of 50/51V creates a coordination challenge with downstream overcurrent units, since the voltage restriction effect can decrease the pickup current to a low enough level for the primary substation to trip before the secondary substation protections have time to act. Following settings are used for primary to secondary coordination of overcurrent protections.

	Pickup	Curve	Dial	Time
51F	320 A	INVERSE	0,15	1
50F	1680 A	-	-	0,20 s

Table 5 Primary Substation Overcurrent Settings

	Pickup	Curve	Dial	Time
51F	320 A	Inverse	0,05	
50F	1500 A	-	-	0,00 sg

Table 6 Secondary Substation Overcurrent Settings

Figure 14 shows coordination of 51 curves for primary (red) and secondary (blue) substations.

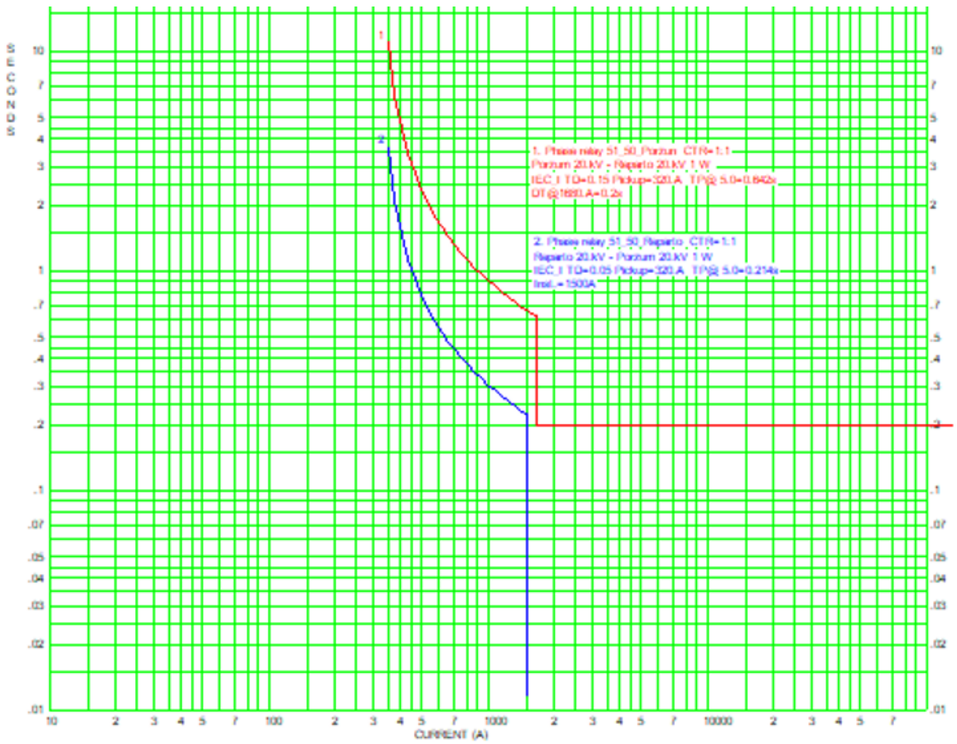

Figure 14 Timed-overcurrent protection coordination between primary and secondary substations.

To obtain correct coordination of 50/51V protection required in primary substation, two different scenarios are recognized:

1. Primary substation applies 50/51V protection while secondary substation maintains 50/51 units only (current).
2. Both primary and secondary substations apply 50/51V protection (future).

On scenario 2, no further coordination is required since at nominal voltage curves are correctly coordinated, while, in the case of a fault at secondary substation, voltage drop registered by secondary substation will be higher than the one registered by the primary substation, due to line impedance, and therefore pick up drop will be higher in secondary substation avoiding miscoordination and allowing secondary substation to trip before primary as expected. However, for scenario 1, the risk of voltage drop making primary substation 50/51V protections trip before 50/51 protections of secondary substations needs to be contained. For this purpose, 50/51 protections of primary substation can be used to restrain the operation of 50/51V. This allows 50/51 V to detect fault even under low phase current but maintaining coordination with the secondary substation.

7.2 Distance Protection 21 Settings

The coordination of distance function on a branched MV grid brings the challenge of retaining selectivity with nearby branches which are usually protected by fuses. A strategy that prioritizes fast tripping has been selected according to the distribution system operator common practices. Under this strategy, distance protection Zone 1 was set to cover 80% of the main line between the primary (130/20 kV) substation and the secondary (20kV/400V) substation. This criterion has the limitation of tripping at distance protection speed (less than 20 ms) for fault at branches near the 130/20 kV substation, but this has been mitigated by adjusting the reclosure strategy to allow nearby fuses to act in case of permanent faults.

A Zone 2 set to 3 times Z1 reach is enabled to detect faults at the lines going out of the secondary substation, with a timing of 0.2 sec (higher that the operation time of the overcurrent element for the minimum short circuit current at the secondary substation) and therefore maintaining coordination.

An additional Zone 3 is enabled, set to 3 times Z1 reach, but 0 sec timing. Allowing for fast tripping of faults further than the secondary substation. Additional logic is applied to allow the trip only if overcurrent elements do not pick up, since primary and secondary substations 51 units are set to the same pickup, primary substations units not picking up indicates that secondary substations would also not detect the fault, and therefore is distance Zone 3 in charge of detecting such faults.

8. CONCLUSIONS

After testing of the proposed solutions in real time simulation and the setup of a prototype for a pilot testing, following conclusions were made.

- Solution based on Voltage Based Faulted Phase Selector Algorithm improves selectivity of protections by avoiding dependence on current fault patterns which can be severely modified by full or partial inverter interfaced sources.
- The magnitude of fault current from inverter interfaced is restricted by the inverter capacity, therefore the addition of impedance-based algorithm (21) to medium voltage sources improves reliability by diminishing the dependence on current and factoring in the change in voltage magnitude.
- Inverter interfaced sources are seen by the system as a varying angle source impedance. Dynamically compensating the impact of this varying source impedance improves the operation of distance protection by dynamically adapting reactance characteristic angle.
- Coordination of 21 protection on distribution networks proves to be a challenge to maintain both fault clearance speed and selectivity given the extensive use of fuses, while coordination of 51V with downstream overcurrent protections results challenging given the lack of precise grid characterisation usually seen on distribution level grids.

9. ACKNOWLEDGEMENT

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