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Dynamic Grid Voltage Support from Distributed Energy Resources during Short-Circuits

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Abstract—Grid codes are consistently updated in order to increase the operation efficiency of the power system. In many utilities, Low-Voltage-Ride-Through (LVRT) capability of Distributed Energy Resources (DERs) is nowadays a grid code requirement, according to which DERs should stay connected to faulty grid and support the voltage. This paper intends to illustrate the benefits gained from the LVRT capability of DERs to support voltage dynamically under short-circuit conditions. Both synchronous generators and inverter-interfaced DERs are included in the analysis, initially as single grid-connected units and subsequently as generating units connected to a benchmark distribution system. The importance of the synchronous machines voltage regulator parameters and that of the inverter-interfaced DERs' control system is highlighted. Local versus dispersed integration of DERs, the line type of the distribution feeder and the DERs regulator/controller operation are shown to play important role in grid voltage support during short-circuits if DERs are operating independently or together in a distribution system. Relevant conclusions occur from the simulation results.

Index Terms--Distributed generation, distribution system, Low-Voltage-Ride-Through, short-circuits, voltage support.

I. INTRODUCTION

Distributed Energy Resources (DERs) are being continuously integrated into power systems due to the significant environmental, technical and economic advantages they provide in the power system operation by relieving the power generation and transmission system [1]. To this end, a variety of technologies, capacities and techniques for safe and stable connection to the transmission and/or distribution system have been developed, making proper operation of DERs inside power systems an active research theme.

The alternations that DERs cause to the traditional power system structure are well known [2] and till today the protection systems act as indispensable units for a reliable power system operation under fault conditions [1], [2]. However, as the penetration level of DERs in power systems increases, the instant disconnection of all DER units inside the system due to a fault is prohibited. Therefore, utilities started proposing technical guidelines at an early stage to ensure reliable connection of distributed generating plants to the distribution and transmission system. A comprehensive review of international Fault-Ride-Through (FRT) concepts applied since 2007 is provided in [3]. Similar guidelines are adopted and are being continuously updated by the European operators ENTSO-E [4] and EDSO [5]. In a glance, the FRT guidelines propose the voltage/frequency/power support of a grid, which operates with a considerable amount of DERs, during transient contingencies. DERs connected to a power system are primarily responsible to remain connected with the grid at least for a short time period, which depends on the severity of the contingency, providing voltage/frequency support in the meantime.

The FRT philosophy for conventional generators is thoroughly described in [6]. As crucial research emphasizes on how power electronics interfaced generating units can mimic synchronous generators [7], a number of FRT schemes has been developed based on this principle. In addition to various modifications regarding the DERs operation mode, which can be found in the recent literature [8], protection settings need always to be revisited when FRT technique is adopted [9].

This work focuses only on low voltage problems occurring in distribution systems due to short-circuit faults and in the remaining of this paper we will deal exclusively with the Low-Voltage-Ride-Through (LVRT) aspect of the FRT problem of DERs installed in distribution systems. In other words, we will adopt the grid code requirement to avoid an instant disconnection of DERs for any given grid fault and we will investigate the capability of DERs to support voltages at the distribution level by injecting reactive current for a specific short time period.

The paper is organized as follows. In Section II, the LVRT concept is briefly introduced and the corresponding voltage support requirements imposed by utilities to DER units are presented. Section III addresses the dynamic voltage response of a synchronous hydro-generator (SG) and that of a photovoltaic (PV) system under faulty grid conditions at the connection point. Various factors affecting the voltage response of the units under short-circuit conditions are examined in order for the reader to obtain a clear understanding of their importance. In Section IV, the abovementioned DER units are tested connected to the CIGRE MV benchmark system and different scenarios concerning the DERs location, the DERs penetration level and the load dynamics are simulated. The LVRT impact on a system-wide perspective is highlighted. Finally, the derived conclusions are summarized in Section V.

II. LOW-VOLTAGE-RIDE-THROUGH CONCEPT

Many countries around the world have begun standardizing LVRT requirements, but until today, there is not a global standard developed, although there is a continuing progress on this [4], [5], [8]. In line with the recent Distribution System Operator (DSO) practices, indicated by corresponding national grid codes, the general LVRT requirements can be summarized to the following statements:

- All generating units (synchronous machine-based and inverter-interfaced) connected to MV networks must remain connected to the grid during a short-circuit fault, for a time that depends on the voltage dip caused by the fault. Otherwise, the instant disconnection of a large amount of DG due to a fault may threaten the stability of the whole system [1].
- During the short-circuit fault, the generating units that sense a voltage drop above a predefined threshold must quickly generate reactive power, proportionally to the voltage drop magnitude. This way, each generating unit close to the fault location supports grid voltage dynamically.
- After short-circuit is cleared, all generating units should consume reactive power less or equal to that before the short-circuit occurrence.

The first requirement is usually quantified with the help of a proper characteristic curve. Fig. 1 shows typical forms of the LVRT characteristic curve as retrieved by [10]. The curves in Fig. 1 hold for inverter interfaced DERs (named type-2 in [10]), whereas borderline 1 forms the LVRT curve for synchronous generators (named type-1 in [10]). In the general case of type-2 generating plants, no plant must be disconnected for a 100% voltage drop with a duration of up to 150 ms. Underneath the blue solid line there are no requirements to remain grid connected. For short-circuits causing the voltage magnitude to drop to values above the borderlines 1 or 2, no DER unit should be disconnected. Especially, for post-fault voltages lying in between borderlines 1 and 2, some additional DER unit operating actions are allowed if agreed with the DSO. For example, the DER unit can be allowed to feed-in the short-circuit, it can be allowed to be temporarily disconnected for up to 2 s, or the borderline 2 can be shifted. In this paper, we adopt the type-1 LVRT curve, which is stricter than that for type-2 DERs and therefore it is more challenging to meet.

ENTSO-E and various system operators provide similar LVRT curves for inverter-interfaced and synchronous generators. However, ENTSO-E [4] additionally requires the voltage-time profile of each DER unit to remain above the corresponding LVRT curve for the entire period, starting from the fault occurrence up to the fault clearance.

The second requirement is quantified for inverter-interfaced units by a respective characteristic curve, which indicates the exact amount of reactive current that should be injected/absorbed by the DER unit in case of a voltage magnitude violation at the DER connection point. Fig. 2 shows a typical characteristic graph for the reactive current output of DER units under short-circuit conditions, originally proposed in [11]. The lower/upper voltage magnitude thresholds form a dead-band with limits ±10% around the nominal terminal bus voltage U_n. If the terminal bus voltage U of the DER unit obtains a magnitude that is outside of this dead-band, the generating unit must produce or absorb reactive current trying to restore the voltage magnitude inside the dead-band. The exact reactive current i_q produced or absorbed by the DER unit is proportional to the voltage variation $\Delta U = U - U_o$ with regard to the pre-fault voltage magnitude U_o at the connection point and is determined by the equation:

$$i_q = k\Delta U \qquad (1)$$

The slope k (droop factor) shown with the red solid line in Fig. 2 should be taken greater than or equal to 2.

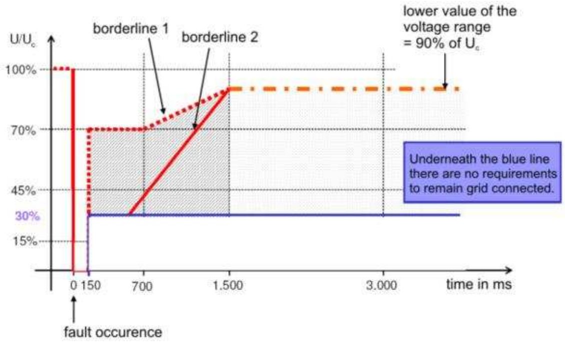


Fig. 1. LVRT characteristic curve [10].

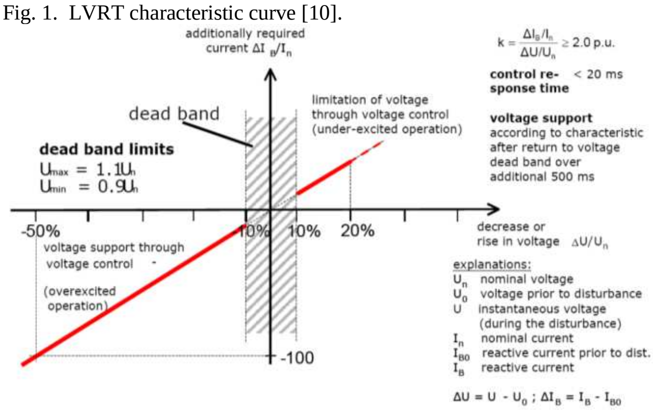


Fig. 2. Reactive current output curve [11].

III. DYNAMIC VOLTAGE RESPONSE OF SINGLE GRID-CONNECTED DER UNITS

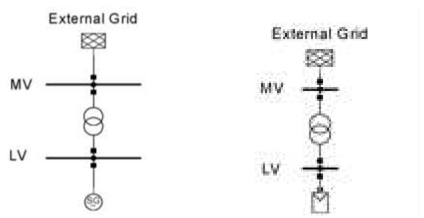
A. Voltage Response of Synchronous Generators

The voltage response of synchronous machines during short-circuits has already been under extensive research and today there are certain guidelines to be followed [12]. During short-circuits, synchronous generators, that are capable of controlling their terminal voltage, react by supplying field current/voltage (thus reactive power) to the fault in order to support the terminal voltage and subsequently the voltages of the system. This happens until the protection system disconnects the machine or the fault is being cleared. It is important to mention that the fault should be cleared before the synchronous machine becomes desynchronized [13].

It is obvious that a synchronous generator inherently follows the reactive power injection principle imposed nowadays for DER units. However, the voltage support capability of a synchronous generator is not unlimited and it depends largely on the Automatic Voltage Regulator (AVR) parameters and more generally on the excitation system structure and its limitations. Governor action is not expected to play important role on the voltage behaviour of the synchronous generator unless the short-circuit fault lasts for a considerable time duration. The latter is due to the larger time constants involved with the governor dynamics.

This subsection tries to figure out how different types of excitation systems and how different voltage regulator parameters influence the dynamic voltage behaviour of a small-scale synchronous generator. For this purpose, a synchronous generator whose characteristics come from a real hydroelectric plant in Grevena area, Western Macedonia, Greece, is considered in the simulation analysis. In particular, a 1.66 MVA, 660 V, 50 Hz hydro-turbine synchronous generator is assumed connected to a weak external grid with a short circuit power of 100 MVA via a step-up transformer to boost the voltage from the plant output voltage to the 20 kV of the medium voltage external grid, as shown in Fig. 3a. The generator is considered to operate with a unity power factor, while its nominal power factor is 0.95 inductive.

The generator is implemented as a power plant model with hydro-turbine governor and excitation system. The IEEESGO model has been used to represent the hydro-turbine governor, with its parameters given in [14]. Three different excitation systems have been also modelled; the standard models DC1A, AC5A, and ST1A. The plant is considered to operate with unity power factor under normal system conditions, whereas it switches to a voltage control mode during short-circuits. The scenario simulated in PowerFactory is a solid three-phase short-circuit at the MV bus, which is cleared after 150 ms.



(a) SG with governor and AVR (b) PV system

Fig. 3. Single connected DER unit.

Fig. 4 illustrates the voltage magnitude response of the MV bus for each of the three different excitation systems, considered independently in operation, assuming equal AVR gain and equal limits for the maximum excitation voltage of these models. As it can be seen in Fig. 4, the excitation system itself regulates the terminal voltage of the generator in a different way. If the AVR gain is varied, as made for the AC5A excitation system and shown in Fig. 5, the terminal voltage stabilizes in a different level. Finally, the excitation voltage limit is varied to show its significant influence on the voltage response of the generator under short-circuits in the grid. The corresponding results are depicted in Fig. 6.

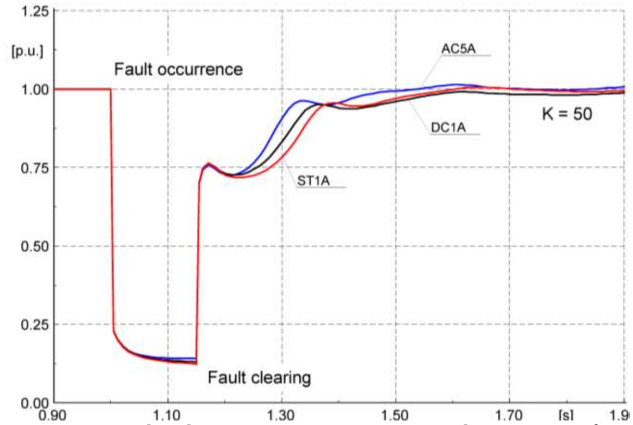


Fig. 4. Terminal voltage response assuming equal AVR gain for all excitation systems.

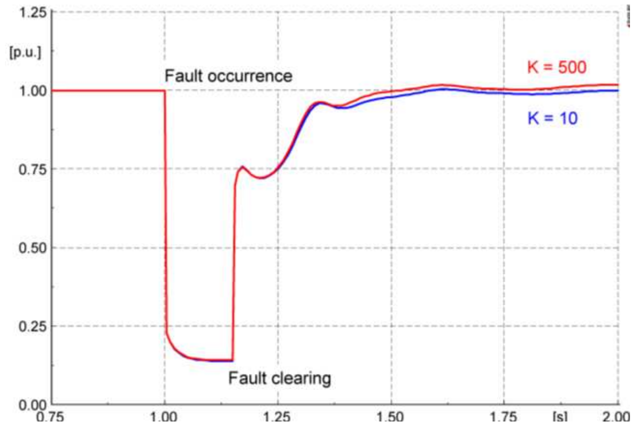


Fig. 5. Terminal voltage response for different AVR gains of AC5A.

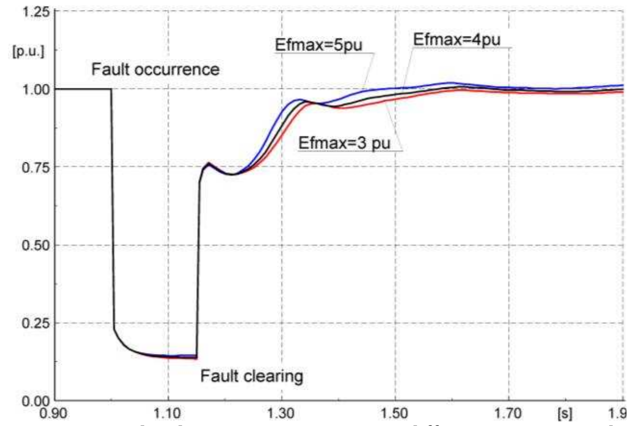


Fig. 6. Terminal voltage response assuming different excitation voltage limits for AC5A model.

A number of additional simulations have been performed by varying other parameters, e.g. the time constants of the excitation systems and the regulators. Overall, it can be concluded that critical parameters for voltage support is the maximum permissible excitation voltage $E_{f,max}$, which is beneficial to be high and this depends on the excitation system type as well, and the AVR gain. The time constants seem not to play an important role. It should be noted that although the differences observed in the simulated voltages are small, the voltage increase would be greater if a stronger external grid and more/larger generating units were assumed.

B. Voltage Response of the Photovoltaic System

In this subsection, a 500 kVA, 400 V PV system is considered, connected to the 20 kV external grid (having a short-circuit power of 100 MVA) through a step-up transformer (Fig. 3b). The standard PowerFactory model for PV systems has been used for this purpose, which adapts to all the LVRT requirements addressed in Section II. The simulated scenario is a solid three-phase short-circuit at the MV bus, which is cleared after 150 ms.

Fig. 7 depicts the voltage magnitude at the LV bus for the simulated scenario. The solid three-phase short-circuit in the MV bus causes a zero voltage magnitude. For this 100% percent voltage drop at the MV bus, the PV system must stay connected to the grid for at least 150 ms and it must inject reactive current according to (1). The greater the droop factor k is, the more the voltage at the LV bus is supported for the same voltage drop, as shown in Fig. 7. Moreover, for a given droop factor k, if the maximum permissible fault current contribution I_{max} by the PV system increases, the produced reactive current i_q also increases, supporting the LV bus voltage more efficiently as can be seen in Fig. 8.

The effect of the external grid characteristics is examined next. At first, the short-circuit power of the external grid is varied to represent a stronger connection. The simulated scenario is a non-solid three-phase short-circuit which causes a voltage drop equal to 55% for the initially assumed external grid (100 MVA short-circuit power). By increasing the short-circuit power of the external grid without changing the R/X ratios, the voltage drop at the MV bus decreases, however the support of the LV increases (Fig. 9).

IV. Dynamic Voltage Response in a Grid

In the previous section, the contribution of a single DER unit in supporting the grid voltage is studied. Now, the connection of several DERs on a wider distribution system is analysed. Different scenarios concerning local versus dispersed integration of DERs inside the distribution network, alternative distribution line types, different DER types, load restoration mechanisms etc. will be considered to investigate to what extend the combined voltage supporting operation of DERs during short-circuits is effective for the grid.

The system used for this study is the European MV Benchmark System proposed firstly in [15] and then adopted from CIGRE. This distribution system is depicted in Fig. 10. It consists of two radial feeders; an underground cable feeder departing from Bus-1 and an overhead line feeder departing from Bus-12. The loads represent residential and industrial consumers, expressed with a static voltage dependent model. The synchronous hydro-turbine generator and the PV system introduced in the previous section will be used as DER units. Detailed technical information about the models of the CIGRE MV distribution system can be found in [15].

Note that the protection system is ignored in this analysis. Thus, we consider faults of various durations in the sense to highlight the LVRT capability of the DER units and its effect on grid voltage support under extreme fault conditions.

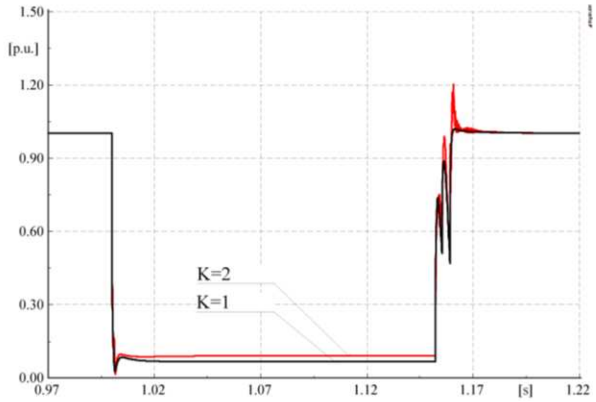


Fig. 7. LV bus voltage response for different k values.

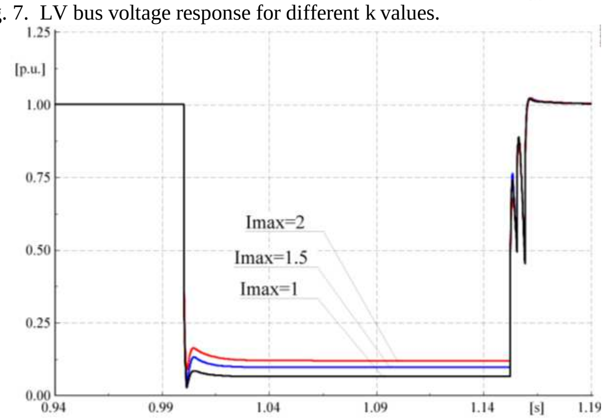


Fig. 8. LV bus voltage response for different I_{max} values.

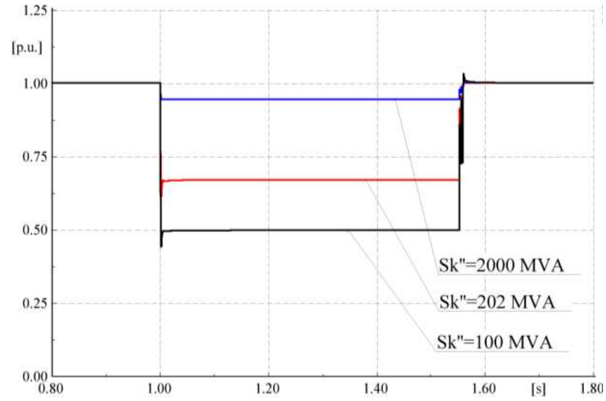


Fig. 9. LV bus voltage response for stronger external grid connections.

A. Local Integration of DERs

The analysis starts by considering the connection of all DER units of interest to the same MV bus of the underground cable feeder, through their step-up transformers. Then, the simulation of short-circuits with various fault resistances, occurring on the 110 kV Bus-0, is considered.

At first, a PV park is assumed being connected to the Bus-3. A varying number of PV systems inside the park is taken into consideration in order to investigate the effect of the DERs penetration level (PL) on the grid voltage. In particular, the following PLs are assumed:

- 5 PV systems, meaning a $PL_1 = 9.3\%$
- 15 PV systems, meaning a $PL_2 = 27.9\%$
- 24 PV systems, meaning a $PL_3 = 44.7\%$

For all independent PV systems, the same droop factor k = 2 is assumed.

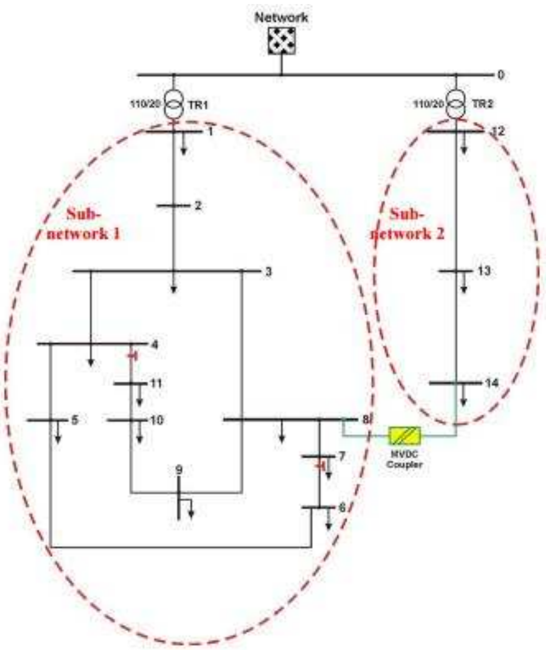


Fig. 10. CIGRE MV Benchmark System [15].

Fig. 11 depicts the increase in the voltage magnitude of Bus-3, and subsequently of that of all downstream buses, due to the reactive current injection of the PV systems on Bus-3 during a non-solid three-phase short-circuit. The red solid curve represents the voltage magnitude response at Bus-3 without PV systems, whereas the remaining curves correspond to the voltage response with regard to the different PLs. The increase in the grid voltages would be greater if the maximum fault current contribution I_{max} of each PV system was higher. Similar conclusions hold if the PV systems are connected to the overhead line feeder.

By assuming synchronous generators in place of the PV systems, grid voltage support is slightly greater. An indicative case is the connection of eight 1.5 MW rated synchronous generators to Bus-3, which correspond to a PL close to the PL_4. As can be seen from Fig. 13, the marginal increase in voltage magnitude between the no DER case and the PL_4 case is larger if assuming synchronous generators than that of assuming the PV systems (Fig. 12).

B. Dynamic Representation of Industrial Loads

As described earlier, the system loads represent residential and industrial consumers, expressed with a static voltage dependent model in the CIGRE benchmark system. In this subsection, the industrial loads are modelled as induction motors in order to examine the voltage response during short-circuits if load dynamics are present. Typical motor parameters have been taken from a 6.3 kV induction motor. In order to match exactly the motor load with the initial industrial load demand on each bus, more than one motors have been assumed connected to the buses (if required) through step-up transformers and/or the motor loading level is varied. The case of one PV system connected to Bus-3 is considered, to highlight the influence of the motor dynamics on the voltages.

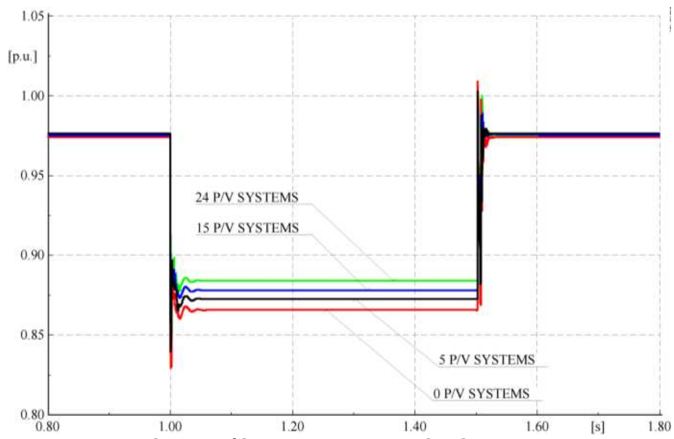


Fig. 11. Bus-3 voltage profile vs. PV penetration level.

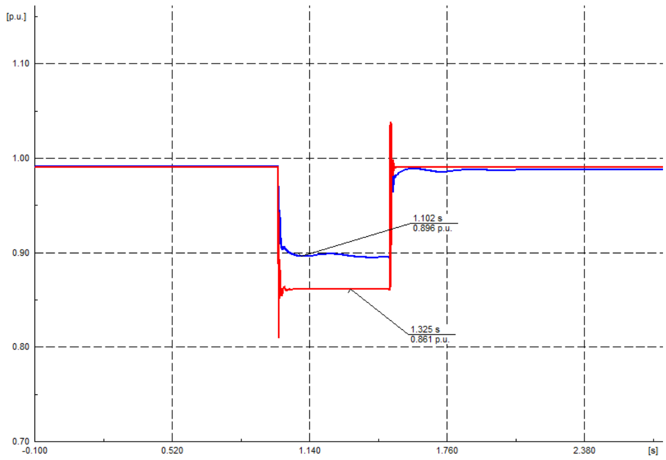


Fig. 12. Bus-3 voltage profile due to synchronous generators.

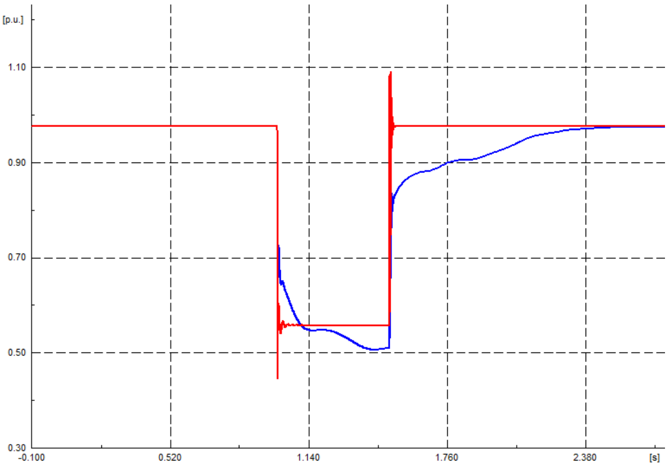


Fig. 13. Bus-3 voltage profile for static and dynamic industrial load.

Fig. 13 clearly shows the difference in the response of the Bus-3 voltage for a non-solid three-phase short-circuit at Bus-0. The red solid line represents the case of static industrial loads, whereas the blue solid curve represents the case with induction motor loads. It can be seen that the voltage restores slower to the pre-fault value after the fault clearance, whereas the voltage drops dynamically to a lower magnitude during the fault.

C. Dispersed Integration of DERs

Contrary to the previous approaches, next, DERs are connected to all buses of the benchmark system. Since each PV system is 0.5 MVA rated, by connecting one PV system to every bus, the following maximum penetration levels are approximately obtained:

- 11 PV systems in the cable feeder, i.e. $PL_4 = 20.4\%$
- 3 PV systems in the overhead line, i.e. $PL_5 = 6.6\%$

A solid three-phase short-circuit at Bus-0 is simulated. Fig. 14 (respectively, Fig. 15) depicts the residual voltage resulted on each underground feeder bus if all industrial loads are considered static (respectively, dynamic) and PV systems are progressively installed, starting from Bus-1 up to Bus-11. One can observe that when PVs are connected to all of the buses of the underground cable feeder, the difference between the faulty voltage of the first and the last MV bus is smoothed out, whereas with one PV connected at Bus-1, a significant voltage drop appears moving downstream to the feeder.

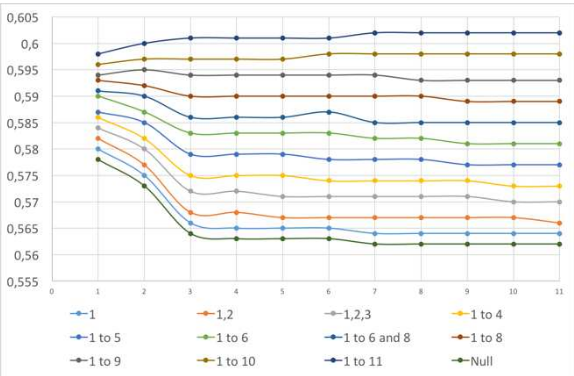


Fig. 14. Residual voltage profile of the underground line assuming static industrial loads.

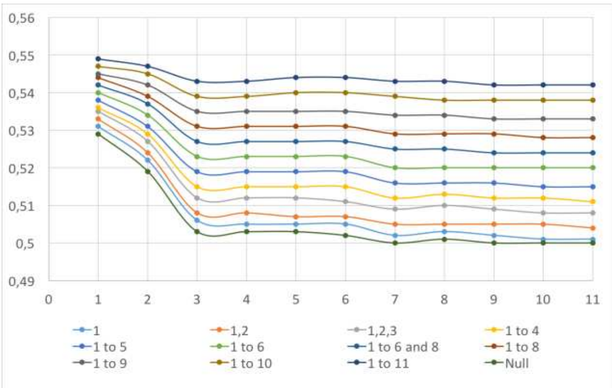


Fig. 15. Residual voltage profile of the underground line assuming motor industrial loads.

V. CONCLUSIONS AND FUTURE WORK

LVRT requirements, when adopted, definitely support the grid status under short circuit conditions. Higher penetration level results in a larger risk for the system stability if a vast amount of DERs is suddenly lost due to a fault. On the contrary, the higher the penetration level the greater the voltage support is. Synchronous generators with AVR and proper excitation system type and parameters should be selected. Inverter interfaced units should inject reactive current and must support an increased current output during short-circuits. The voltage profile at the DER connection point should be improved in order to remain above the corresponding LVRT curve for all the period, starting from the fault occurrence up to the fault clearance, which is not always achieved nowadays. Load restoration mechanisms play also important role.

Future work will emphasize in proposing modifications in the inverter-interfaced DER control methods that could prove efficient for grid voltage support under symmetrical and asymmetrical short-circuits. For example, negative/zero-sequence current or combined active/reactive current injection in distribution systems with similar reactive/resistive characteristics will be examined.

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