Comparison of Methods Using only Voltage Measurements for Detecting the Origin of Voltage Sags in the Modern Distribution Networks

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Abstract—In this paper, we analysed two methods, M1 and M2, for determining in which network the voltage sags originated. The problem referred to the High Voltage (HV) and Medium Voltage (MV) systems interconnected by HV/MV stations. The methods were compared using time-domain simulations, short circuits were forced on the HV or the MV network, the voltage sags were observed, and M1 and M2 were applied. Comparisons of M1 and M2 behaviours were done for the same network architecture with and without Distributed Generation (DG).

***Index Terms*-- Power quality, Power distribution, Voltage Sag, Distributed power generation.**

I. INTRODUCTION

Conforming to IEEE standard 1159-1995, a voltage sag is defined as a decrease to between 0.1 and 0.9 p.u. in Root Mean Square (RMS) voltage at the power frequency for durations of 0.5 cycle to 1 min [1], [2].

The voltage sag is one of the most severe power quality disturbances of the voltage [3]; it can be due to varying causes like lightning, loose connections, accidental short circuits, tree branches touching the line, birds hitting the line, etc. [4]. This phenomenon can cause production loss in a modern industrial plant with automated production lines [5]-[8].

Voltage sags propagate throughout the interconnected networks, so that the sags that the customer experiences at the lower voltage level could originate in the distribution network at medium voltage (MV) level or even in the transmission system at high voltage (HV) level. The knowledge of the origin of the measured voltage sags is the starting point for any effective countermeasure to mitigate the phenomenon.

This scenario evidences the importance and the complexity to determine the origin of the voltage sags in interconnected networks.

The methods proposed in literature to identify the origin of voltage sags can be categorized as Single Monitor-based (SM-based) methods, Multi-Monitor-based (MM-based) methods [9], and hybrid methods (HM) [10].

The SM-based methods measure the electrical variables in just one point to ascertain if a measured voltage sag originated in the upstream system or in the downstream system from the measurement point [4], [8], [11].

The MM-based methods use several points of measurements in different busses [12], [13]. Then, the acquired data are processed to identify the exact origin of the voltage sag rather than establishing the part of the system where the voltage sag originated.

Finally, the HM methods comprise two main methods, namely M1 and M2 fully described in [10]. M1 has some features of SM-based methods and M2 some of the MM-based methods. The common aspect of both the HM methods is that they measure only the residual voltage[1], the time of the occurrence and the duration of the sag in more busbars at MV level. These measures are used for detecting the part of the interconnected network, HV or MV, where the measured voltage sags were originated. The most interesting aspects of the HM is that they can be easily applied to real systems since they only use basic metrics of the voltage sags without using any further electrical measures.

Nowadays, the modern distribution networks are characterized by and increased use of the distributed generation (DG) for facing the growing complexity and size of consumer energy demands. Although DG inclusion has undeniable advantages such as voltage profile improvement, increased grid capacity and increased power delivery reliability, it can influence the reliability of the SM-based, MM-based and HM. Some studies were carried out to improve the power quality through the use of DG [14], [15].

In [10], with the proposal of the methods M1 and M2, we referred to some preliminary tests effected for comparing their performance on networks in presence of DG. In this paper we provide a detailed analysis on their reliability in ascertaining the correct origin of the voltage sags measured at MV level for faults in the HV and in the MV networks also in the presence of DG.

[1] The residual voltage is the minimum RMS value of the voltage during the fault

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II. RECALL ON THE METHODS M1 AND M2

For introducing the methods M1 and M2, it is useful to consider a section of the interconnection between transmission (HV level) and distribution networks (MV level). Fig.1, in particular, shows a section constituted by two stations, i.e., HV/MV, each of which is equipped with two transformers[2]. Fig. 1 shows two possible locations of a short circuit, i.e., position p, which is in the HV network, and position q, which is in the MV network. Each secondary bus of the station is equipped with a monitoring system (MS_i) to measure the voltage sags as prescribed by the IEC 61000-4-11[16].

In the case of a three-phase short circuit, we can refer to the single-phase voltage during the fault. Each MS_i can measure the voltage sags V_i, V_j, V_k, V_f. These measured voltage sags can be due to a short circuit that occurred either in node p of the HV network or in node q of the MV network. The objective of M1 and M2 is to establish where the voltage sags originated, i.e., in the HV network or in the MV network.

M1 was proposed by a regulatory resolution of the Italian Energy Authority [17]. It performs a pair-to-pair analysis of the voltage sags that are measured almost contemporaneously on the MV busbars of the same HV/MV station. With reference to Fig.1, M1 analyses the data measured by the couple MS_1 and MS_2, separately from the data measured by the couple MS_3 and MS_4.

M2 was proposed in [10] to overcome some drawbacks of M1. It uses data that come from more *MSs* that are installed in more HV/MV stations electrically close each other. With reference to Fig.1, M2 analyses all together the data measured by the measurement systems from MS_1 to MS_4.

M1 and M2 are briefly described below.

M1 attributes the origin of all single voltage sags that occur only at one of the MV busses from the same HV busbar to the downstream system, i.e., the MV network.

In case of voltage sags that are measured at all the MV busbars derived from the same HV busbar, M1 establishes that their origin is in the upstream system, i.e., the HV network, if all of the following conditions are met:

– the residual voltages of the voltage sags differ by no more than 3%;
– the voltage sags occur within 60 ms of each other;
– the durations of the voltage sags are within 20 ms of each other.

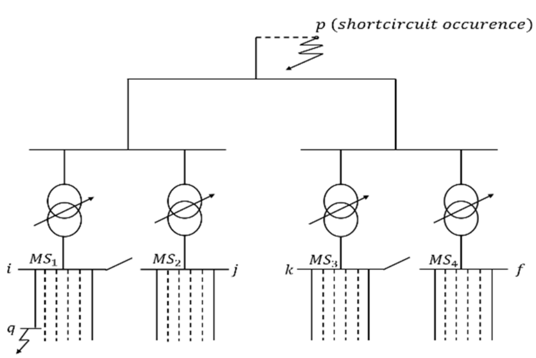

Figure 1. Scheme of reference for M1 and M2.

M2 was developed starting from this basic consideration on the propagation of the voltage sag: the affected areas of the nodes at higher voltage levels can involve a broad portion of the lower voltage network, including both busses of the same HV/MV stations and busses of different HV/MV stations. As a result of this observation, we analysed all the voltage sags that occurred almost contemporaneously in a given portion of the interconnected system.

Moreover, we considered the effect in the service operation of the increasing penetration of the DG.

First, the main consequence of the high penetration of DG was that the transformers of the same HV/MV station were not in parallel, i.e., the switch between the secondary busses was in the open position (Fig. 1). This service condition allows different positions of the transformers' on-load tap changer (OLTC) at the same HV/MV station.

Second, the presence of high penetration of DG can cause the transformers to provide intermittent power flow. Also, these considerations forced us to release the constraint of M1 on the difference between the amplitudes of the voltage sags that were measured almost contemporaneously (occurred in the 60-ms time range).

Summarizing, in case of voltage sags that are measured at all the MV busbars of HV/MV stations electrically close each other, M2 establishes that their origin is in the upstream system, i.e., the HV network, if they occurred within 60 ms of each other. With reference to Figure 1, V_i, V_j, V_k, and V_f were analysed all together; if the time of their occurrence were inside a time range of 60 ms, they are considered to have originated in the HV network.

III. COMPARING M1 AND M2 ON TEST SYSTEM

The performance in attributing the exact origin of M1 and M2 was compared by the time domain simulations of the test system in Fig.2. The time domain simulations were performed by means of SimPowerSys of MATLAB©®.

Starting from a steady state balanced operation, three phase short circuits were forced in HV network or in the MV network, the resulting voltage sags were detected and analysed using M1 and M2.

The system consists of an equivalent HV power system that supplies the HV feeders at the point of common coupling (PCC); each HV feeder is connected through HV/MV stations to four feeders of the MV networks. The electrical parameters of the main components of Fig.2 are reported in Table 1.

Referring to Fig.2, in Europe the switches S1 and S2 are open in normal operating conditions due to the different control needs of the voltages at the secondary busses of the transformers [10].

Three possible locations of fault position (FP1, FP2 and FP3) were considered; the FP1 was on feeder 1 of the HV network (see Fig.2), whereas FP2 and FP3 were positioned in the MV network on feeder 1 and feeder 2, respectively.

[2] In Europe, the switches are open in normal operating conditions due to the different control needs of the voltages at the secondary busses of the transformers

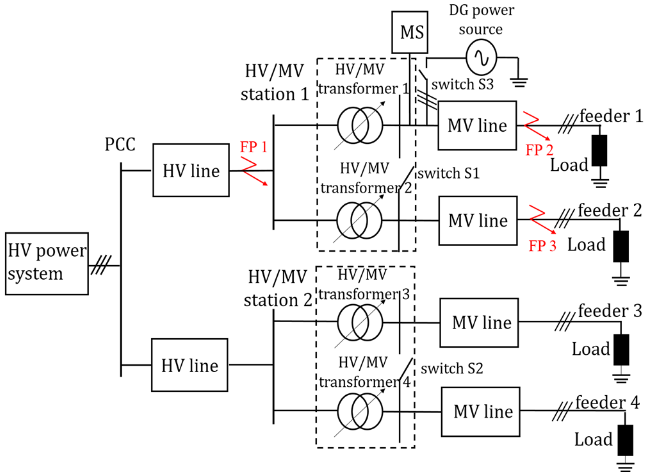

Figure 2. Scheme of the test system for SimPowerSys simulations

For the comparison of the performance of the M1 and M2 also in the presence of DG units, for each fault, two separate type of tests were performed with (switch S3 was closed) and without (switch S3 was open) the DG source.

Table 1. The electrical parameters of electrical components

No.	Components	Details
1	Equivalent HV system	1000MVA, 150kV, 50Hz
2	HV/MV transformer	63MVA, 150/20kV, YY
3	Load	20kV, 250kW, 10kVAr
4	HV Line	Overhead, 30km
5	MV line	Overhead, 10km

Both RMS and the sinusoidal waveforms of the voltage were measured at the secondary of the HV/MV station, in the point where the measurement system (*MS*) was positioned [18]. For the sake of clarity, in Fig.2 only one *MS* was shown but each transformer was provided with a *MS* positioned at the secondary bus.

The methods M1 and M2 were used to identify the origin of the measured voltage sags in the following four cases,

- *Case A* Fault in the HV network (FP1) and DG disconnected;
- *Case B* Fault in the HV network (FP1) with DG connected;
- *Case C* Fault in the MV network (FP2) and DG disconnected;
- *Case D* Fault in the MV network (FP3) with DG connected.

In all the previous cases the voltage was detected at the MS for all the four feeders; for all the case the short circuit occurred at 0.1 second and cleared at 0.3 second. Furthermore, the voltage waveform was commonly presented in the RMS values in p.u. for only one phase, being the voltage magnitude the same for each phase.

Case A

Both MS_1 and MS_2 on feeder 1 and feeder 2 detected a short interruption. The RMS voltage waveform of one phase on feeder 3 is shown in Fig.3.

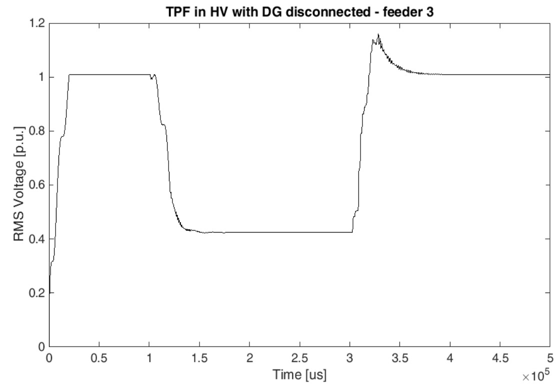

Figure 3. RMS voltage measured by the MS_3 of the feeder 3

Fig 3 shows the complete time evolution of the RMS voltage. The RMS voltage during the fault, before the clearing action of the protection switch, goes down to 0.4 p.u.. This is the value of the residual voltage that is measured by the MS_3 of the feeder 3.

In this condition, let us consider the voltage on the other MV feeder (feeder 4).

Fig.4 shows that on feeder 4 the voltage sag follows the same waveform as on feeder 3 (Fig. 3); the magnitude of the residual voltage during the fault was 0.4 p.u.. Considering the system layout in Fig.2, the voltage waveform on feeder 4 is the same as the one on feeder 3, shown in Fig.4. This behaviour is evident considering that the impedance travel of the fault to reach feeder 3 and feeder 4, is the same.

We compared the reliability of the methods M1 and M2 in attributing the correct origin of the voltage sag to the HV network.

M1 correctly attributes to the HV network the voltage sags measured at the second HV/MV station (transformers 3 and 4); M2 correctly attributes the measured voltage sags to the HV network for the second HV/MV station (transformers 3 and 4). On feeder 1 and feeder 2 no voltage sags are detected since two short interruptions occurred, M1 and M2 cannot be applied for determining the origin of the voltage interruptions.

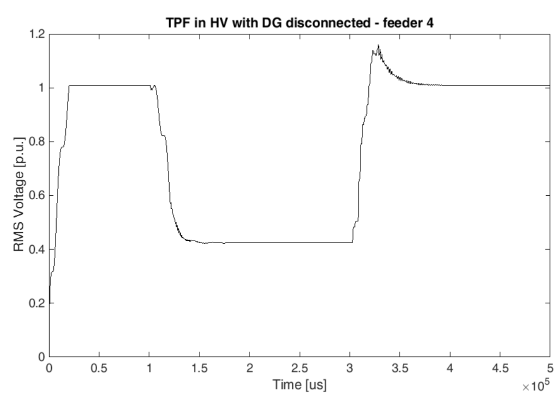

Figure 4. RMS voltage measured by the MS_4 of the feeder 4

Case B

In the presence of DG, the active and reactive power provided by the DG unit was sufficient to keep the residual voltage just over 0.9 p.u.. Consequently, no voltage sag was measured at the MS_1 on the feeder 1 where the DG is installed.

Let us consider the behaviour of the voltage magnitude on the feeder 2 (Fig. 5).

The behaviour of the voltage magnitude was different from the case with DG disconnected; in fact, in this case no voltage interruption occurred since the DG present on feeder 1, is sufficient to step up the voltage, on feeder 2, to 0.2 p.u. during the fault. The voltage on feeder 2 was then influenced by the presence of DG on feeder 1. The voltage trends detected by MS_3 and MS_4 were the same as the previous case; the voltages on feeder 3 and feeder 4 were not influenced by the presence of DG on feeder 1.

The methods M1 and M2 in this case worked as follows.

M1 wrongly attributed the voltage sag detected by the MS_2 on feeder 2 to the MV network since only one voltage sag was registered at one of the MV busbars of the HV/MV station. M1 correctly attributed to the HV network the voltage sags measured by the MS_3 and MS_4 on the feeder 3 and 4 (the RMS voltages on the feeders differed by no more than 3%).

M2 analysed all the voltage sags that occurred at both the HV/MV stations; the time of their occurrence were inside a time range of 60 ms and they were all correctly considered to have originated in the HV network. M2, in fact, does not only consider the voltage sags measured at the MV busbar of the transformers of the same HV/MV station, but also those registered at the other HV/MV stations.

Case C

Fig.6 shows the voltage magnitude on feeder 1 in the presence of the fault in the MV network. The RMS voltage during the fault, before the clearing action of the protection switch, reached 0.8 p.u. This is the value of the residual voltage that was measured by the MS_1 of the feeder 1.

Regarding the feeder 2, the MS_2 did not register a voltage sag, but only a small temporary voltage reduction (Fig.7).

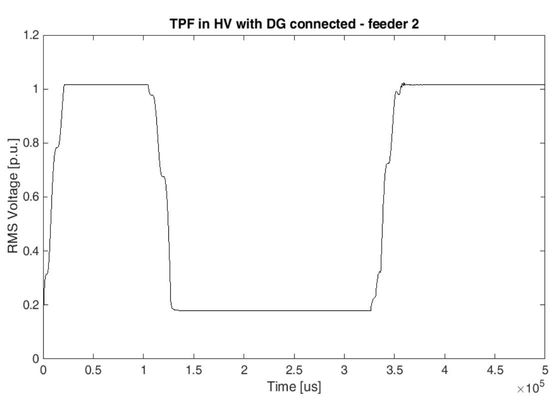

Figure 5. RMS voltage measured by the MS_2 of the feeder 2

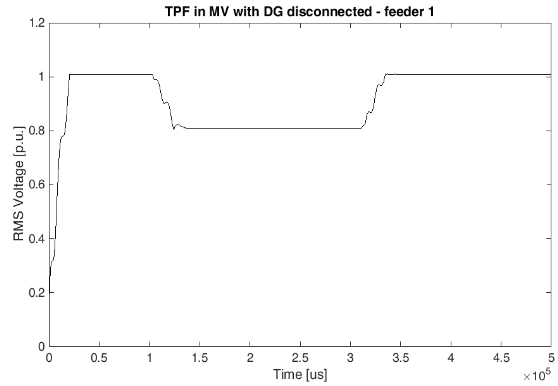

Figure 6. RMS voltage measured by the MS_1 of the feeder 1

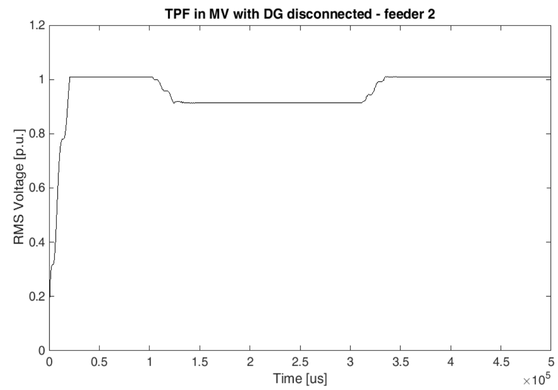

Figure 7. RMS voltage measured by the MS_2 of the feeder 2

M1 and M2 correctly attribute the detected voltage sag to the MV network because the voltage sag was detected only on feeder 1; on feeder 3 and 4 no voltage sags were detected.

Case D

In this case, the DG was connected to feeder 1 but the fault occurred on feeder 2.

Fig.8 shows the time evolution of the RMS voltage magnitude on feeder 2 where the fault occurred; it is evident that the DG source could not sustain the voltage on feeder 2 over 0.9 p.u.. The MS_1 on feeder 1 did not register any voltage sag.

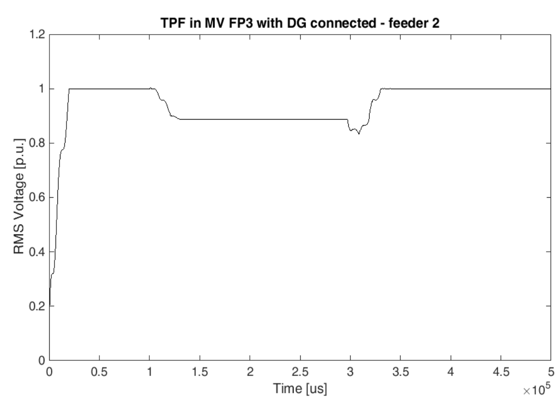

Figure 8. RMS voltage measured by the MS_2 of the feeder 2

Let us analyse the voltage also on feeder 3 (Fig. 9) because the operating conditions were different with respect to both feeder 1 and feeder 2.

Fig.9 shows that the MS_3 did not detect any voltage sag; in fact, only a very slight drop of the voltage magnitude was caused by the fault on the feeder 2.

In this case, both M1 and M2 correctly attributed the voltage sags on feeder 2 to the MV network.

Table 2 summarizes the results of M1 and M2 for the examined cases.

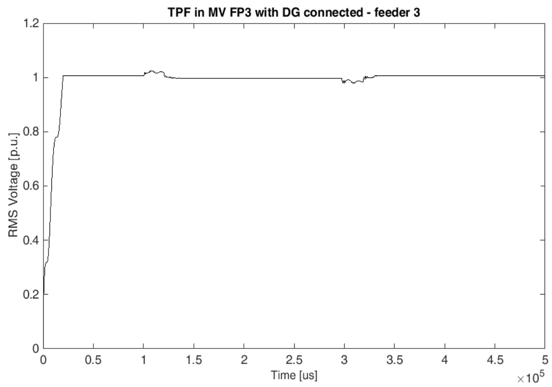

Figure 9. RMS voltage measured by the MS_3 of the feeder 3

Table 2. Results of M1 and M2 for the examined cases

Case	#station	Origin by M1	Origin by M2
Case A Fault in the HV	1	voltage interruption	voltage interruption
	2	correct	correct
Case B Fault in the HV	1	incorrect	correct
	2	correct	correct
Case C Fault in the MV	1	correct	correct
	2	no voltage sag	no voltage sag
Case D Fault in the MV	1	correct	correct
	2	no voltage sag	no voltage sag

From the Table 2, in the presence of traditional DG units (cases B and D), the accuracy of method M2 presented appreciable improvements compared to M1 in the case of voltage sags due to faults in HV (case B).

This was primary due to the absence of the maximum limit on the difference of the residual voltages of the measured voltage sags. Secondly, M2 ascertained the common origin of these sags in the HV network by analysing also the voltage sags measured in other electrically-close HV/MV stations.

For a fault in HV in the case in which the DG supported the voltage at the local bus (up to cancel the voltage sag as in the Case B) thanks to the analysis of further MV busses of other HV/MV stations, M2 correctly ascertained the common origin of these sags in the HV network.

In case of fault in the HV network, if only one sag were measured in the time of contemporaneity (60 ms) in all the electrically-close HV/MV stations, the presence of DG could cause the error of attribution of M2, i.e., the incorrect assignment of the origin of the sag to the MV. As previously specified, this could occur only in very improbable cases. For example this could occur when an HV/MV station with only two transformers or HV/MV stations with more transformers and with all the units of DG in all the feeders except for one, supporting the voltage during the fault occurring in the HV network.

IV. Conclusion

Two methods for establishing the origin of measured voltage sags in interconnected networks were introduced. These methods, namely M1 and M2, use only the main data of measured voltage sags. Comparisons of the behaviour of M1 and M2 were carried out also in the presence of DG. The results of the time domain simulations using *SimPowerSys* of Matlab allowed a valuable comparison of the two methods, even if in the case of a very simple network. M2 presented interesting improvements with respect to M1, due to the release in the condition regarding the difference of the magnitude of the measured voltage sags, and to the analysis of the sags measured not only in one HV/MV station but in several HV/MV stations electrically close to each other. Finally, in the considered cases a fault occurred in a MV line did not cause any voltage sag in other MV line electrically close.

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