EMTP Model for Analysis of Distributed Generation Impact on Voltage Sags

Juan A. Martinez-Velasco, Jacinto Martin-Arnedo

Abstract—Small generation units connected to distribution systems can improve end-user power quality; e.g. by providing voltage support. However, the presence of distributed generation (DG) changes the radial nature of distribution systems and affects the performance of the protection system. DG can also affect during- and post-fault voltages; in addition, voltage sags are highly influenced by the type of protective devices and the coordination between them. This paper is aimed at exploring the impact that DG can have on voltage sags characteristics at distribution levels when the main cause of voltage sags can be either at a transmission or a distribution network.

Keywords: Distributed Generation, Power Quality, Voltage Sag, Modeling, Simulation.

I. INTRODUCTION

IT is commonly accepted that the installation of small generation units at distribution levels has many advantages: economical (energy efficiency), environmental (reduction of gaseous emissions), technical (voltage support) and even political (competition) [1] - [3]. Although costs associated with DG technologies are still high, they can be a solution for those situations in which high power supply reliability is needed, or when the construction of transmission lines and large power plants is not supported by end-users.

However, the installation of DG sources raises new challenges, e.g. the radial topology of distribution networks does not change, but the power will no longer flow in a single direction. DG islanding is one of the main concerns [4] - [7], and although islanded operation is not generally allowed, DG may successfully operate in island if there is a balance between load and generation.

Characteristics of voltage sags in a distribution network that are caused at the transmission level can be affected by the presence of DG. Characteristics of voltage sags caused from inside the distribution level can be affected by the presence of DG as well as by the placement of protective devices and the coordination between them. This paper explores the impact that DG can have on the characteristics of voltage sags in a distribution network with a high penetration of embedded generation, assuming that the voltage sag cause can be either at the transmission or the distribution level.

An EMTP model of a small distribution network, including protective devices, has been created to analyze the DG impact on the characteristics of voltage sags. The study has been carried out using the ATP (Alternative Transients Program) and the library of modules developed by the authors for representing components of distribution networks.

The main features of the test system are detailed in Section II. Pre-fault steady-state conditions are presented in Section III. The main parts of this work are Sections IV and V, where results derived from the simulation of the test system are shown and analyzed. A simplified analysis of the retained voltage at sensitive equipment nodes during symmetrical faults is presented in Section VI. Main conclusions and future works are summarized in the last section.

II. TEST SYSTEM

Fig. 1 shows the diagram of the test system used in this paper. The substation transformer is grounded at the lower voltage side by means of a zig-zag reactor, which limits the current caused by a single-line-to-ground fault to 800 A. Fig. 2 shows the time-current curves of the protective devices installed in the system. Modeling guidelines used to represent the test system were discussed in [8].

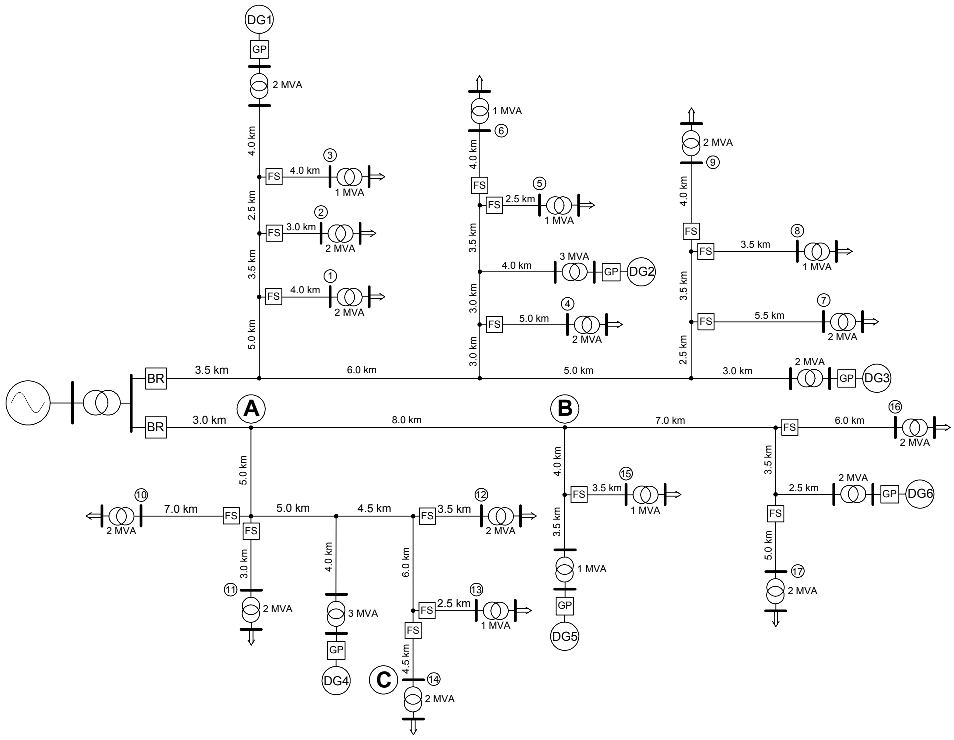
Ratings and electrical parameters of synchronous generators are shown in Table I. The block diagram of the excitation control is presented in Fig. 3. A single-mass model representation will be used for representation of the mechanical system of synchronous generators. The effect of primer movers will be neglected and a constant mechanical energy input will be assumed in simulations. Although the effect of the mechanical parameters will not be very important on voltage sag characteristics, these parameters cannot be neglected when analyzing the transient performance of the system [9]. Since a wide range of mechanical parameter values will be used in simulations, they are not provided. Note that all generation units have the same p.u. values, no electronic interface has been assumed for any generation unit, the maximum load (that can be supplied from distribution transformers) exceeds the substation transformer rated power, distributed generators can supply more than 50% of the maximum load and represent 65% of the substation rating.

Only LV loads are assumed. In addition, all the studies presented and analyzed in this paper have been carried out with a constant impedance model.

This work is supported by the Spanish Ministerio de Investigación y Ciencia, Reference ENE2005-08568/CON.

Juan A. Martinez-Velasco is with the Departament d'Enginyeria Elèctrica, Universitat Politècnica de Catalunya, Barcelona, Spain (e-mail of corresponding author: jamv@ieee.org).
Jacinto Martin-Arnedo is with ITC-2, 08908 Barcelona, Spain. (e-mail: jacinto.martin@gvia.itc2.com).

Presented at the International Conference on Power Systems Transients (IPST'07) in Lyon, France on June 4-7, 2007



HV equivalent: 110 kV, 1500 MVA, X/R = 10
Substation transformer: 110/25 kV, 20 MVA, 8%, Yd, X/R = 10
Distribution transformers: 25/0.4 kV, 6%, Dy, X/R = 10
DG transformers: 25/6kV, 8%, Yd, X/R = 10
Lines: $Z_{1/2} = 0.61 + j0.39$, $Z_0 = 0.76 + j1.56$ Ω/km

BR = Circuit Breakers
FS = Fuses
GP = Generator protection

Fig. 1. Diagram of the test system.

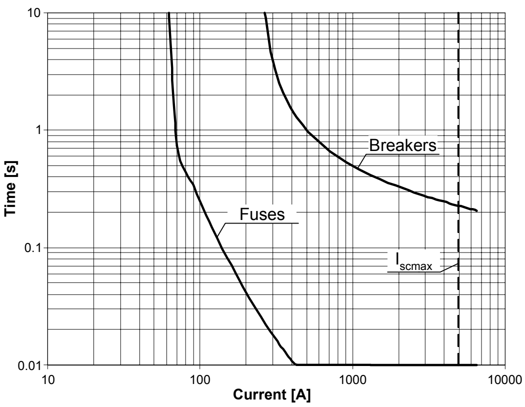


Fig. 2. Time-current characteristics of protective devices.

TABLE I
ELECTRICAL SPECIFICATION OF THE SYNCHRONOUS GENERATOR

Parameter	Value
Rated frequency	50 Hz
Rated voltage	6.0 kV
Number of poles	4
Armature resistance: R_a	0.0041 pu
Armature leakage reactance: X_l	0.1200 pu
d-axis synchronous reactance: X_d	1.7000 pu
d-axis transient reactance: X_d'	0.2383 pu
d-axis sub-transient reactance: X_d''	0.1847 pu
d-axis open-circuit transient time constant: T_{do}'	3.1949 s
d-axis open-circuit sub-transient time constant: T_{do}''	0.02872 s
Zero-sequence reactance: X_0	1.4000 pu

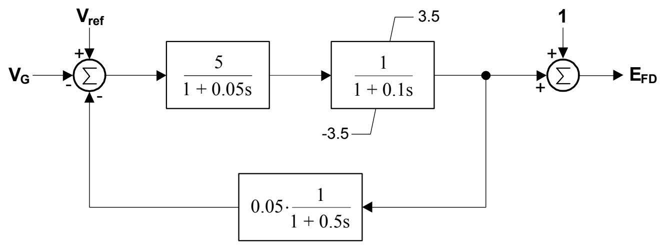


Fig. 3. Block diagram of the excitation control.

III. STEADY STATE OPERATING CONDITIONS

Although different steady state operating conditions (prior to any voltage sag) were analyzed, only two scenarios are reported in this paper. Tables II and III show the voltages that result with minimum and maximum load at the LV load nodes and the synchronous generator terminals, respectively. The active power fraction supplied by DG units with respect to the active power supplied from the substation is 91% with the maximum load and 142% with the minimum load.

Note that even with DG the voltage drop at some LV nodes can reach up to a 10% of the rated voltage. In actual distribution networks this can be mitigated by regulating the substation transformer and installing voltage regulators. The voltage regulation from the substation transformer can be represented by changing the actual voltage supplied from the HV network equivalent. A model of the voltage regulator has been neither developed nor applied in this work.

TABLE II
STEADY STATE CONDITIONS – LOAD NODES

Load node	Maximum load		Minimum load	
	Load (MVA, pf)	Voltage (pu)	Load (MVA, pf)	Voltage (pu)
1	1.85, 0.75	0.947	0.25, 0.65	0.986
2	1.80, 0.80	0.949	0.35, 0.90	0.986
3	0.90, 0.90	0.960	0.20, 0.85	0.985
4	1.70, 0.90	0.950	0.40, 0.85	0.983
5	0.90, 0.80	0.943	0.15, 0.80	0.985
6	0.95, 0.85	0.942	0.25, 0.75	0.979
7	1.80, 0.80	0.919	0.30, 0.80	0.982
8	0.85, 0.95	0.930	0.15, 0.90	0.983
9	1.90, 0.70	0.905	0.25, 0.65	0.981
10	1.95, 0.80	0.929	0.18, 0.77	0.985
11	1.90, 0.95	0.952	0.34, 0.93	0.984
12	1.75, 0.85	0.916	0.64, 0.82	0.967
13	0.90, 0.80	0.900	0.15, 0.72	0.972
14	1.70, 0.85	0.900	0.34, 0.80	0.970
15	0.90, 0.95	0.968	0.12, 0.85	0.991
16	1.95, 0.80	0.931	0.18, 0.75	0.989
17	1.70, 0.95	0.951	0.35, 0.95	0.988

(1) Voltage values correspond to the LV side of distribution transformers and were obtained on a 230 V basis (rms phase-to-ground).
(2) Power values correspond to a rated voltage of 400 V, rms phase-to-phase.
(3) The power factor (pf) in all loads is lagging.

TABLE III
STEADY STATE CONDITIONS – SYNCHRONOUS GENERATORS

Unit	Maximum load		Minimum load	
	P/Q (MW/MVA)	Voltage (pu)	P/Q (MW/MVA)	Voltage (pu)
1	1.356, 0.697	1.031	0.348, 0.165	1.0
2	2.169, 1.047	1.031	0.494, 0.255	1.0
3	1.398, 1.108	1.031	0.347, 0.227	1.0
4	2.165, 1.149	1.021	0.466, 0.428	1.0
5	0.750, 0.237	1.021	0.177, 0.072	1.0
6	1.511, 0.728	1.021	0.328, 0.166	1.0

(PU voltage values correspond to generator terminals and were obtained on a 6 kV basis).

IV. VOLTAGE SAGS CAUSED AT THE TRANSMISSION LEVEL

A high percentage of voltage sags experienced at LV load nodes are caused at the transmission level. However, the characteristics of voltage sags (magnitude, duration) measured at LV nodes can be very different from the characteristics measured at the HV side of the substation transformer. The connection of distribution and substation transformers can significantly alter these characteristics, except for three-phase voltage sags. In addition, the presence of DG can also mitigate voltage drops at distribution nodes.

The simulation of the effect that voltage sags caused at the transmission network can have on load nodes located downstream the lowest voltage side of the substation transformer can be performed without including any protective devices except those aimed at protecting distributed generation units against abnormal voltages, and perhaps unbalance loading.

According to IEEE Std 1547 [5], the clearing time (i.e. the time between the start of an abnormal condition and the DG ceasing to energize the local electric power system) should be based on the (during-fault) voltage range, see Table IV. The standard states that the protection system shall detect the rms value of each phase-to-phase voltage, except for a grounded wye-wye transformer connection, in which case phase-to-neutral voltages should be detected.

TABLE IV
INTERCONNECTION SYSTEM RESPONSE TO ABNORMAL VOLTAGES [5]

Voltage range (% of base voltage)	Clearing time (s)$^{(1)}$
V < 50	0.16$^{(2)}$
50 ≤ V ≤ 88	2.00
110 ≤ V ≤ 120	1.00
V > 120	0.16$^{(2)}$

Notes: (1) Default clearing times for DG > 30 kW
(2) For 60Hz systems.

An aspect to be considered is the expected duration of voltage sags caused by faults located at the transmission network. This value can depend on several aspects (e.g. fault location or stability margins), but in general it will be rather short. One can assume that very rarely it will last for more than 10 cycles when the cause is a three-phase fault.

An ATP module was developed for simulation of voltage sags upstream the substation transformer. The capabilities of this module allow users to specify voltage sag characteristics (retained voltage, duration, phase-angle jump, initiation of sag) independently for each phase. Note that the highest voltage at the substation transformer is a subtransmission voltage; one should, therefore, assume that the module is representing sags caused at both transmission and subtransmission levels.

Fig. 4 depicts simulation results obtained with maximum load. These results were derived without activation of DG protective devices. As expected, the pu magnitude of voltage sags at generator terminals and distribution nodes can be very different from the pu magnitude measured at the HV substation transformer.

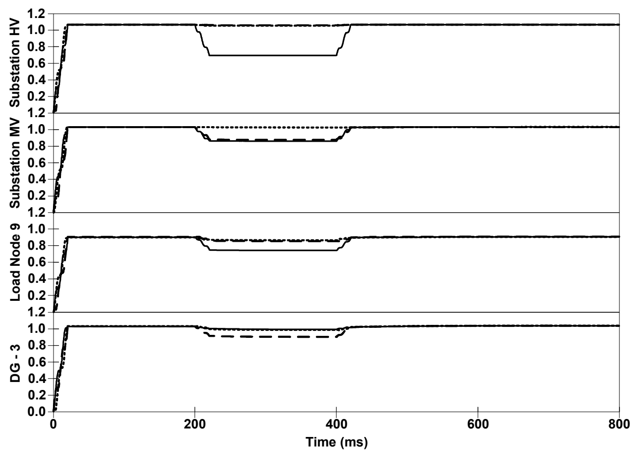


Fig. 4. Single-phase voltage sag caused at the transmission network.

When analyzing these and other simulation results, several aspects have to be considered:

- It is evident the effect of the connections of substation, interconnect DG and distribution transformers.
- The reactive power flow measured at the lowest voltage side of the substation decreases significantly during a voltage sag, and it can even reverse the direction, flowing from DG units to the transmission network. This will obviously affect the voltage drop between the substation terminals and the nodes located downstream.
- A third aspect that can affect sag magnitudes are the ratios between the different impedances involved in a voltage drop and the ratios between the rated powers of the substation transformer and DG units, see Section VI.

The most important conclusions from this study can be summarized as follows:

- During symmetrical sags, DG units will reduce the voltage drop, but they will not avoid sensitive equipment trip except with shallow sags (see Section VI). On the other hand, DG protection can operate and separate units from the system except for very short fault durations.
- During non-symmetrical sags, the voltage drop at DG terminals and LV load nodes can be significantly reduced due to the different transformer connections rather than to the presence of DG units.

The influence of the transformer connections can also play an important role when the voltage sag is caused with a phase-angle jump.

The effect of a loss of power supply from the transmission level has not been analyzed, although this study is somehow covered in the next section by those cases in which a fault condition causes a feeder breaker opening.

V. VOLTAGE SAGS CAUSED AT THE DISTRIBUTION LEVEL

The characteristics of voltage sags caused by faults originated within the distribution network depend on several factors:

- fault characteristic (type, duration, resistance);
- distribution transformer connections;
- substation grounding;
- rating of DG units;
- design of the different protection systems;
- operating conditions and DG penetration level;
- fault and monitor locations.

Although voltage sags can be either symmetrical or asymmetrical, and several parameters can be needed for a full characterization, only the retained voltage and the duration are analyzed in this work. Retained voltages at LV nodes can be different from those at the MV nodes. In fact, with the connection used in this work for distribution transformers, there will not be swells at the LV sides [8].

Simulations have been carried out assuming that a circuit breaker opens the three poles, irrespectively of the short-circuit type, while fuses are of current-limiting type and open only the faulted phases. As for the coordination between these protective devices two possibilities are analyzed: fuse saving (fuses are slower than breakers) and fuse blowing (time-current characteristics are those depicted in Fig. 2).

A consequence derived from the protective device operation is that voltage sags will not be always rectangular, since the coordination between protective devices can produce multiple events with different retained voltages. Characterization of multiple events (magnitude and duration) becomes then an important issue [10].

The protection model of a small synchronous generator is much more complex than the protection of a distribution network. In addition, not only the generator protection but also the interconnect protection has to be taken into account. Interconnect protection satisfies the utility requirements to allow the connection of the generator to the grid, while generator protection provides detection of internal short-circuits and abnormal operating conditions [6], [7], [11].

In the present study, the protection model of small generators could include devices against overcurrents, abnormal voltages, unbalance loading and reverse power.

DG units can affect voltage sag magnitude before and after the breaker of the faulted feeder has opened. Since the impact will be smaller with minimum load, the study will begin by assuming this scenario. If the DG impact is not very significant with minimum load, it will be even less important under other operating conditions.

Due to room limitations, simulation results analyzed in this section correspond only to the less and the most severe voltage sags; i.e. to voltage sags caused respectively by 1LG and 3L faults. And only three fault locations (nodes A, B and C in Fig. 1) are considered.

The following subsections analyze voltage sags caused respectively with fuse saving and fuse blowing.

A. Fuse saving

The network is protected only by breakers, and fuse models are not included in simulations.

An important aspect of the study is the clearing time as a function of the type and location of the fault. Table V shows the times required by the breaker of the bottom feeder to open. Note that, with the time-current curve selected for breakers, there are fault positions for which the clearing time can be much longer than 2 seconds. In those cases, mechanical transients must be carefully analyzed and the system model must be improved (e.g. DG prime movers should be included).

TABLE V
CLEARING TIMES (FAULT RESISTANCE = 0)

Fault type	Node A	Node B	Node C
1LG	790 ms	1220 ms	6150 ms
3L	270 ms	400 ms	780 ms

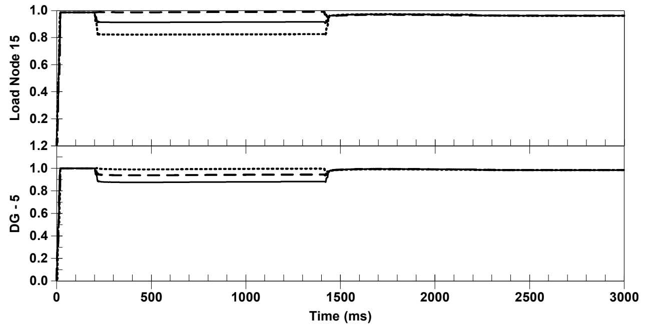
Fig. 5 and 6 show some plots of voltage sags caused by 1LG and 3L faults. Table VI summarizes the main results, for which a zero fault resistance was assumed. Since non-zero resistance values are very usual, one should expect different clearing times and different retained voltages.

TABLE VI
VOLTAGE SAG CHARACTERISTICS

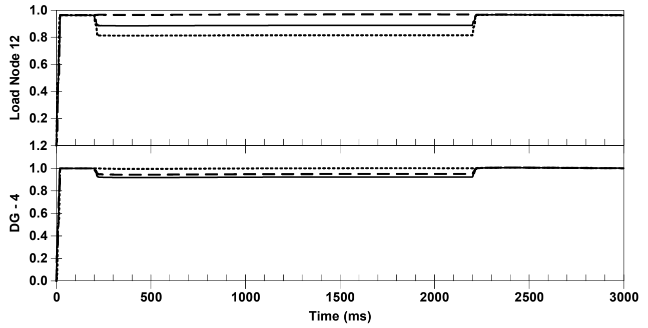
Fault	Upper (Unfaulted) Feeder	Lower (Faulted) Feeder
1LG	Voltages at LV nodes and DG terminals will never be below 90% of the rated voltages.	The during-fault voltages at some phases of LV nodes close to the fault position can be as low as 80% of the rated voltage. The voltages at DG terminals will never be below 88% of the rated voltage.
3L	Only when the fault position is close to the substation (e.g. node A), voltages at DG terminals can reach values as low as 65% of the rated voltage. At LV load nodes the trend is similar, but voltages can be even lower. Power flow can reverse in all DG units.	When the fault position is close to the substation (e.g. node A), the during-fault voltages at DG terminals can reach values as low as 10% of the rated voltage. Voltages decrease after the breaker opens; the voltage reduction will depend on the load demand.

- Plots of Fig. 5 show voltage sags of different durations and caused by faults located at nodes B and C, see Fig. 1. The fault at node C will not cause breaker opening since the clearing time for this case is much longer that the simulated case, see Table V. Voltages in all simulated cases reach the pre-fault values after the feeder breaker opens; that is, DG operates successfully after loads are separated from the substation. These results prove that the impact of a 1LG fault on the DG and LV nodes at the unfaulted feeder is not significant and very few trips should be expected for sensitive equipment supplied from LV nodes located at this feeder. For some LV nodes located at the faulted feeder, the retained voltage can drop up to the 80% of the rated voltage, but DG terminal voltages will be hardly below 90% of the rated voltage.

  With maximum load and after breaker opening, voltages at DG terminals and LV nodes can reach values below 90% of the rated voltage; the drop can be particularly important at some end-user nodes where the retained voltage can be below 80%. However, the impact at DG and LV nodes of the unfaulted feeder is almost negligible, although at some phases of LV nodes can be also below 90%. In all cases, this is due not only to the fault but to the pre-fault voltages, see Table II. Remember that pre-, during- and post-fault voltages can be regulated to a higher value by using voltage regulators and voltage regulation at the substation; so in many instances, the effect of a fault can be easily mitigated.
- Sags caused by 3L faults at the unfaulted feeder can be more severe than those caused by 1LG faults, but (as expected) even with this type of faults retained voltages above 90% of the rated voltage can appear when the fault location is far enough from the substation (e.g. at node C), see Section VI. Plots of Fig. 6 show cases in which the faulted feeder breaker opens always; in the second case the voltage drops after breaker opening and recovers after the fault clears. Since these results were obtained with minimum load, one should expect worse voltage sag performance with any other operating condition.

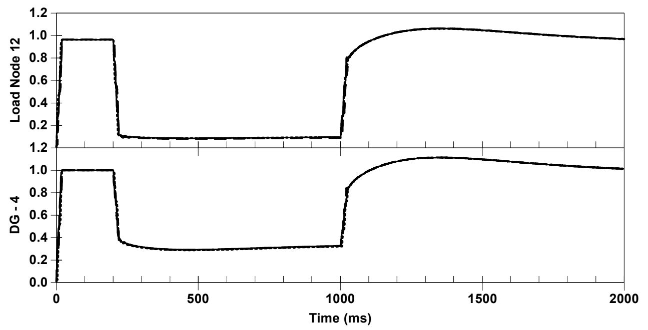


a) Fault location = Node B – Fault resistance = 0 Ω (Duration = 2.0s)

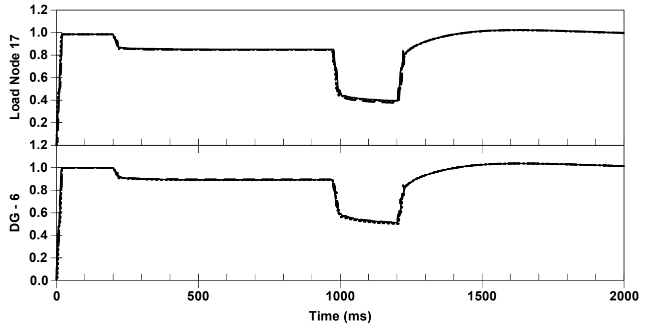


b) Fault location = Node C – Fault resistance = 0 Ω (Duration = 2.0s)

Fig. 5. Voltage sags caused by a 1LG fault – Fuse saving.



a) Fault location = Node A – Fault resistance = 0 Ω (Duration = 0.8s)



b) Fault location = Node C – Fault resistance = 0 Ω (Duration = 1 s)

Fig. 6. Voltage sags caused by a 3L fault – Fuse saving.

B. Fuse blowing

Fig. 7 shows some simulation results when fuses are installed and their current-time curves are as shown in Fig. 2. These results correspond to a fault located at node C (see Fig. 1). Since this is the furthest node from substation terminals, the short-circuit current is the smallest one while the melting time is the longest one. From these results one can conclude that in general only sensitive equipment at nodes downstream the fault location will trip. As shown in Fig. 7a, only the voltage at one phase of the LV node downstream the fuse location will remain with the pre-fault value, while the impact on the closest nodes will not be significant. The case depicted in Fig. 7b shows that, even for a three-phase fault, only sensitive equipment on LV nodes downstream the fuse is affected. The impact on the unfaulted feeder nodes is negligible. The performance with a non-zero fault resistance will be similar although the melting time of fuses will be longer and the impact on sensitive equipment located at the faulted feeder should not be always neglected.

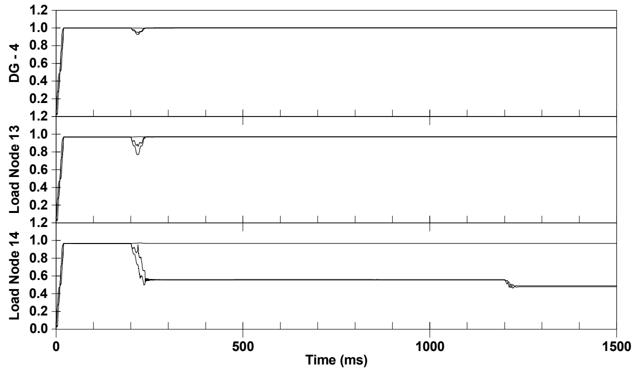
These conclusions are obviously valid only when the fault location is in the zone protected by a fuse; otherwise both results and conclusions would be those analyzed above.

C. Discussion

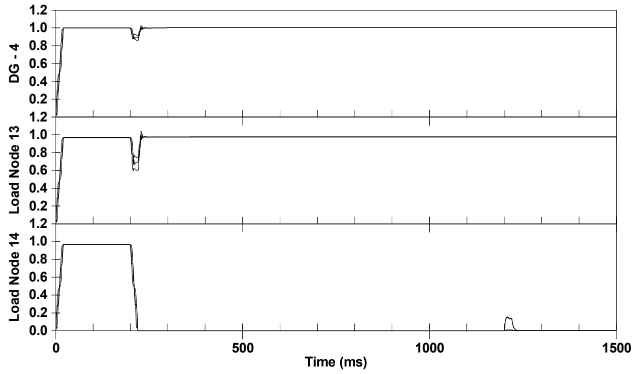
Simulation results presented and analyzed in the previous subsections were obtained by assuming that devices installed to protect DG units and the interconnect transformers did not operate. This could be the situation when the fault is downstream a fuse, but it is not always valid if the fault location is outside a fuse-protected zone. In those cases, DG protective devices could operate according values shown in Table IV.

The main conclusions from all simulation results can be summarized as follows:

- When fuse blowing is allowed and the fault is located inside the zone protected by a fuse, one can assume by default that only sensitive equipment at nodes downstream the fuse will trip. This will not be always true and depend on the fault resistance, the fault and equipment locations, as well as on the voltage tolerance of sensitive equipment.
- When the fault is located outside the zone protected by a fuse or fuses are saved, the effect on sensitive equipment will depend on the type of fault and the response of the DG protection system. Only when a symmetrical fault is far from the substation terminals, sensitive equipment at LV nodes of the unfaulted feeder will not trip. However, the during-fault voltage at nodes on the faulted feeder will be usually below an acceptable value range after feeder breaker opening, even if DG units are not disconnected.
- Sensitive equipment at LV nodes of the unfaulted feeder will withstand most voltage sags caused by 1LG faults. This could be also true for a significant percentage of LV nodes of the faulted feeder if DG units are not disconnected, since during-fault voltages and voltages after feeder breaker opening will be above 90% of the rated voltage. If protection of DG units operates (e.g. due to unbalance loading), then this conclusion will apply in general only to faults with a duration shorter than the clearing time.



a) Voltage sags caused by a single-phase-to-ground fault



b) Voltage sags caused by a three-phase fault

Fig. 7. Fuse blowing. Fault location = Node C, Fault resistance = 0 Ω, Duration = 1.0 s.

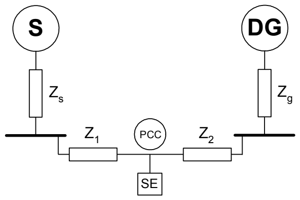
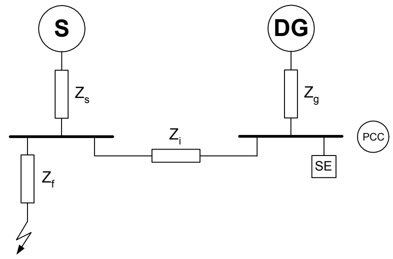
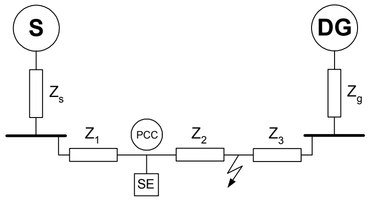
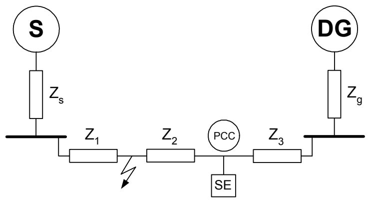
VI. Voltage Sag Calculation

The influence that the parameters of the main source (network equivalent) and the small synchronous generators have on the retained voltage caused by a symmetrical fault will be analyzed. The study will be made by neglecting the effect of the pre-fault currents. Table VII shows the various topologies that have to be considered for the system under study. Since more than one synchronous generator is connected to the test system, parameters involved in expressions should be seen as the parameters of the equivalents seen from the fault location.

These expressions can be also applied when no DG unit is connected to the test system (see Table VIII). Voltages and impedances in the expressions shown in the table are complex quantities (phasors), so even neglecting pre-fault currents the analysis is not easy. Note that the ratio R/X is very small in the main source and the transformers of the test system, but it is greater than unity for lines.

In order to facilitate the analysis, it is assumed that main source and DG voltage magnitudes are 1 pu and their arguments are the same. Table VIII shows the expressions that result from these assumptions with and without DG [12], [13], [14].

TABLE VII
DURING-FAULT VOLTAGES

SYSTEM CONFIGURATION	VOLTAGE SAG MAGNITUDE
	A – The fault is at the transmission level $V_G - V_{SE} = \frac{Z_2 + Z_g}{Z_s + Z_1 + Z_2 + Z_g}(V_G - V_T)$ Z_s = impedance seen from the MV terminals of the substation Z_1 = impedance between the substation and the PCC Z_2 = impedance between the DG unit and the PCC Z_g = impedance seen from the DG transformer terminals.
	B – The fault is at the other feeder $V_{SE} = \frac{Z_g Z_f}{Z_s Z_f + (Z_s + Z_f)(Z_i + Z_g)} V_T + \frac{Z_i Z_s + Z_i Z_f + Z_s Z_f}{Z_s Z_f + (Z_s + Z_f)(Z_i + Z_g)} V_G$ Z_s = impedance seen from the MV terminals of the substation transformer Z_g = impedance seen from the DG transformer terminals Z_i = impedance between the substation and the DG transformer Z_f = impedance between the substation and the fault location.
	C – The fault is between the substation and one DG unit, at the DG unit side $V_{SE} = \frac{Z_2}{Z_1 + Z_2 + Z_s} V_T$ Z_s = impedance seen from the MV terminals of the substation Z_g = impedance seen from the MV terminals of the DG transformer Z_1 = impedance between the substation and the PCC Z_2 = impedance between the fault location and the PCC Z_3 = impedance between the fault location and the DG transformer
	D – The fault is between the substation and one DG unit, at the substation side $V_{SE} = \frac{Z_2}{Z_2 + Z_3 + Z_g} V_G$ Z_s = impedance seen from the MV terminals of the substation Z_g = impedance seen from the MV terminals of the DG transformer Z_1 = impedance between the substation and the fault location Z_2 = impedance between the PCC and the fault location Z_3 = impedance between the PCC and the DG transformer

V_T = voltage at the transmission level; V_G = DG internal voltage; V_{SE} = voltage at the sensitive equipment location

A further simplification can be made by assuming that all impedances have the same X/R ratio or all resistances are neglected. The following paragraphs discuss the results derived from this new assumption and present the conditions to be fulfilled in order to avoid the trip of sensitive equipment.

A. The fault location is at the transmission level

The expression of this case can be rewritten as follows

$$V_{SE} = 1 - \frac{1}{1+x}\Delta V_T \qquad \left(x = \frac{Z_s + Z_1}{Z_2 + Z_g} \right) \tag{1}$$

To obtain a retained voltage at the PCC equal or greater than 90% of the rated voltage, it must be $(1+x) \geq 10\Delta V_T$. Since the value of the ratio Z_s/Z_g is smaller than 0.2 in all synchronous generators, this sag magnitude can be only obtained when the voltage drop at the transmission level is below 12%. That is, the influence of DG units when the voltage sag cause is at the transmission level is negligible.

B. The fault location is at the distribution level

The expression that correspond to the case with DG can be rewritten as follows

$$V_{SE} = \frac{Z_s x + Z_f}{Z_s Z_f /(Z_i + Z_g) + (Z_s + Z_f)} \qquad \left(x = \frac{Z_i + Z_f}{Z_i + Z_g} \right) \tag{2}$$

If $Z_f \approx 0$ (i.e., the fault location is very close to the substation), then it results $V_{SE} \approx x$. To obtain a retained voltage at the PCC equal or greater than 90% of the rated voltage, it must be $Z_i > 9Z_g$. Given the values of Z_g for the different DG units and the impedance per unit length of the distribution lines, the retained voltage at all nodes of the upper feeder will never reach a 50% of the rated voltage with a three-phase fault located on the lower feeder and close to the substation, unless Z_f was very large.

TABLE VIII
SIMPLIFIED EXPRESSIONS OF DURING-FAULT VOLTAGES

Case	With DG (V_T=1) (V_G=1)	Without DG (V_T=1) (V_G=0; Z_g=∞)
A	$V_{SE} = 1 - \frac{Z_2 + Z_g}{Z_s + Z_1 + Z_2 + Z_g} \Delta V_T$	$V_{SE} = V_T$
B	$V_{SE} = \frac{Z_s(Z_i + Z_f) + Z_f(Z_i + Z_g)}{Z_s Z_f + (Z_s + Z_f)(Z_i + Z_g)}$	$V_{SE} = \frac{Z_f}{Z_s + Z_f}$
C	$V_{SE} = \frac{Z_2}{Z_1 + Z_2 + Z_s}$	$V_{SE} = \frac{Z_2}{Z_1 + Z_2 + Z_s}$
D	$V_{SE} = \frac{Z_2}{Z_2 + Z_3 + Z_g}$	$V_{SE} = 0$

$\Delta V_T = (1 - V_T)$= voltage drop at the transmission level

If $Z_f >> Z_s$, $Z_f >> Z_i$ and Z_f is of the same order than Z_g, then $V_{SE} \approx 1$. That is, voltages at unfaulted feeder nodes between the substation and a DG unit that is close to the substation can be above 90% of the rated voltage if the fault location on the lower feeder is far enough from the substation.

C. *The fault location is at the distribution level and the PCC is between the substation and the fault location*

To obtain a retained voltage at the sensitive equipment equal or greater than 90% of the rated voltage, it must be $Z_2 > 9(Z_s + Z_1)$. That is, the point of common coupling must be far from the fault location and close to the substation. In fact, this scenario is the same that results without DG. Therefore, the analysis is well known and can be found in many references, see for instance [12] or [15].

D. *The fault location is at the distribution level and the PCC is between the fault location and one DG unit*

To obtain a retained voltage at the sensitive equipment equal or greater than 90% of the rated voltage, it must be $Z_2 > 9(Z_g + Z_3)$. That is, the point of common coupling must be far from the fault location and close to the DG unit. Since the impedance seen from the MV terminals of a DG transformer increases as the rated power of the generator decreases, the distance between the fault location and the sensitive equipment must increase as the rated power of the DG unit decreases. Actually this scenario can be analyzed by using the results and studies that correspond to the previous case by exchanging parameters of the main source and the DG unit. Note that this can be seen as an important effect of the presence of DG, since the voltage at the point of common coupling considered in this case would be zero without DG, as shown in Table VIII.

VII. CONCLUSIONS

The work presented in this paper has proved that DG can have a positive impact on the characteristics of voltage sags caused at any voltage level. Simulation results have shown that sensitive equipment can withstand voltage sags caused by 1LG faults when DG is present after the feeder breaker opens. This is an important fact, since more than 60% of faults in most systems belong to this type. But even with 3L faults, the retained voltage can be above the threshold voltage under some circumstances, as discussed in Section VI, if DG is present. In any case, a strict application of the protection system response, according to IEEE Std. 1547, could significantly reduce this impact, except with short-duration faults.

The study has been based on the presence of small synchronous generators only, without considering any power electronics interface. Future work should consider the presence of other DG technologies (wind, photovoltaic, fuel-cell), whose impact can be different from that obtained in this work, with special emphasis on electronic-interfaced DG.

A more complete representation of DG units (including models of prime movers and any type of protection) will provide more accurate results and expand the cases to be analyzed. In addition, different results could be also derived from the implementation of different protection schemes (e.g. including reclosers) [8], [16], and from the application of more advanced load models [17].

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