Impact of Distributed Generation Mix on the Effectiveness of Islanded Operation Detection

Dimitrios Tzelepis
dimitrios.tzelepis@strath.ac.uk

Adam Dyśko
a.dysko@strath.ac.uk

EEE Department, University of Strathclyde, Glasgow, G11XQ, UK.

Abstract:
Distributed generation can be understood as a process where large scale power generation is gradually replaced by smaller power generation facilities with reduced power yield, and mostly connected at the system distribution level. One of the most important requirements for interconnecting distributed generation to healthy power networks is the Loss of Mains (or Islanding) detection. During a Loss of Mains (LOM) event a part of the grid (including distributed generation) losses physical connection with rest of the grid. A condition like this should be detected and actions to disconnect distributed generation should be initiated, in order to protect life and property. A very common passive method used to detect an islanding event, is the Rate of Change of Frequency (ROCOF). Since distribution networks nowadays are accommodating a great amount converter-interfaced generation, there is a risk that such methods may fail to successfully operate or operate spuriously, putting system stability at risk. Most of the existing LOM protection performance studies, consider only a single generator within the islanded part of the network. While historically such approach was reasonable, rapidly increasing numbers of DG connections lead to high probability of islanding with more than one generator in the mix. Therefore, this paper, considers various mixes of generation to investigate how this impacts LOM detection performance. In particular studies are undertaken with a few identified most likely combinations of distributed generators.

Keywords: Islanding, loss of mains, distributed generation, plant mix, non detection zone

I. Introduction

Loss of Mains(LOM) or Islanding is a term used to describe a condition when a part of a power network, including distributed generation (DG) losses physical connection with the rest of the grid [1]. As shown in Figure 1, if the breaker at Point of Common Coupling (PCC) will open, a power island will be formed including DG and a local load .

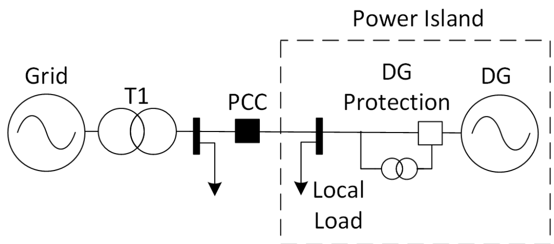

Figure 1: Power Network with interconnected DG

Operating a network in islanding mode contains a lot of dangers for equipment but also for human life. The major ones are [2]:

- Out of phase reclosing
- Insufficient or missing grounding of the islanded part
- Production of huge catastrophic mechanical torques
- Unacceptable levels of Voltage and Voltage Frequency
- Safety hazard for the utility personnel

Consequently such condition should be detected within a time limit (before minimum expected reclosing time), in order for the protection schemes to initiate tripping actions and disconnect the distributed generation. One of the most vital characteristics which determine the performance of LOM protection is the Non-Detection-Zone(NDZ). The NDZ can be described as a region where the protection algorithm cannot be triggered, within a predefined time margin, consequently an islanded operation is not detected.

II. Loss of Mains Detection Methods

There are numerous techniques and approaches for detecting a Loss of Mains event. According to their principle of operation they can initially be allocated to the following three groups [3]:

- Passive Methods
- Active Methods
- Communication Based Methods

The principle of operation of passive methods is that during a LOM event some of the system parameters such a frequency, voltage angle, active and reactive power will be disturbed. Hence by continuously monitoring these parameters a LOM condition can be detected. Some of the most commonly used methods are the Rate of Change of Frequency (ROCOF), Vector Shift (VS), Rate of Change of Voltage Angle Difference (ROCPAD), Rate of Change of Power (ROCOP), Reverse (VAr) [4, 5, 6]. However in UK the most widely used method, to detect a genuine LOM event is ROCOF [3]. Based on this fact, this paper, considers a ROCOF based protection system. In a typical DG interface protection relay ROCOF signal is derived from the three phase voltage signals measured at the terminals of the generator. The expected initial value of ROCOF (following an islanding event) can be estimated as follows:

$$ROCOF = \frac{\Delta P \cdot f}{2 \cdot S \cdot H}$$

Where:

ROCOF: Rate of Change of Frequncy [Hz/s]

ΔP : active power variation during LOM event [MW]

f : system frequency [Hz]

S : DG's rating [MW]

H : inertia constant of the generator [s]

The ROCOF during a genuine LOM event depends on the power imbalance between the output of the generator and the local load, at the time of disconnection. It is worth noting here that the most challenging scenario to detect a genuine LOM using ROCOF-based methods is when the generation meets the local demand both for active and reactive power.

Concerning the active methods, they are continuously and directly interacting with the power network. This is achieved by injecting small signals into the network. By monitoring the response of these signals a decision can be made, whether a LOM occurred or not. Most of the time, active methods are used when inverter based DG is connected to a power network. Some of the frequently mentioned techniques include the Slip Mode Frequency, Active Frequency Drift and Sandia Frequency Shift [7, 8, 9].

When LOM protection is communication based, a communication link between the grid and the distributed generator is required. Grid operators already use networks of extensive communications to control and monitor the state of their systems. Communication based methods are a high promising tool since their NDZ can be effectively non-existent and at the same time they maintain full immunity to external system faults. However it can be expensive due to the cost of communication that is required. Sometimes the communication based methods can be found in the literature under the title "remote methods". Some examples include methods on satellite communications, Phasor Measurement Units (PMU) incorporating internet communication, or radio based [10, 11, 1].

III. System Modelling

Most of the existing LOM protection performance studies, consider only a single generator within the islanded part of the network [12, 13]. Due to increasing number of connections this assumption is no longer true. Therefore, this paper, considers various mixes of generation to investigate how this impacts on the LOM detection performance. Since distribution networks nowadays are accommodating a great amount of converter-interfaced generation and the inertia is significantly reduced, there is pressure to increase the LOM protection settings making it less sensitive to system wide events. With such reduced sensitivity there is a risk that ROCOF based LOM protection methods may fail to successfully operate under genuine islanding scenarios. For the needs of performance evaluation, an 11kV distribution network has been developed, with three different generation technologies. These are directly connected conventional Synchronous Generator (SG), Photovoltaic Panels (PV) and Double-Fed Induction Generator(DFIG), representing the most popular DG technologies. In theory, if all possibilities were to be considered, this would lead to $\binom{3}{1} + \binom{3}{2} + \binom{3}{3} = 7$ different situations which includes single generators as well as mixes of 2 and 3 different technologies. In terms of load representation constant impedance loads were used in all case studies. The 11kV distribution network is shown at figure 2. The line parameters used, have been derived from previous LOM studies included in [13].

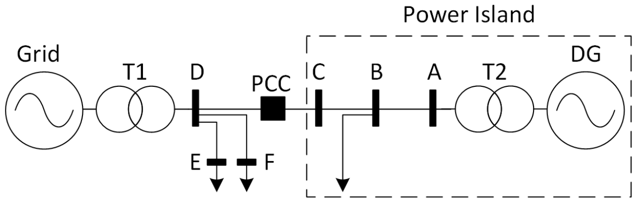

Figure 2: 11kV Power Network with interconnected DG

For each of the interconnection scenarios, genuine LOM events will be created by opening the circuit breaker at PCC. Frequency and ROCOF will be derived from the three phase voltages at busbar A. The NDZ will be determined for the ROCOF protection relay as a percentage of DG MVA rating, both for active and reactive power imbalance at PCC. The imbalance of active and reactive power at the PCC is adjusted independently to determine the NDZ for a range of ROCOF settings as indicated in Table 1. The NDZ is expressed as a percentage of the DG MVA rating according to the following equations:

$$NDZ_P = \frac{P_{PCC}}{S_{DG}} \cdot 100\%$$

$$NDZ_Q = \frac{Q_{PCC}}{S_{DG}} \cdot 100\%$$

Where:

P_{PCC} : Real power imbalance across PCC [MW]
Q_{PCC} : Reactive power imbalance across PCC [MVAr]
S_{DG} : DG's rating [MVA]

Setting Option	ROCOF [Hz/s]	Time Delay [s]
1	0.13	0
2	0.2	0
3	0.2	0.5
4	0.5	0.5
5	1.0	0.5

Table 1: ROCOF Settings

IV. Case Studies

From the seven grouping scenarios the 3 most typical are presented in this paper. The first one includes SG only, the second one SG and PV and the third PV and DFIG. At all three cases the total DG installed capacity is fixed to 2 MVA.

Case Study 1:
In this case study a 2 MVA synchronous generator model is included. The excitation system is iEEE type 1 and the control strategy is a standard active power and voltage (P-V) control. During the simulations the output of the generator has been held constant at 90% prior to LOM event. Figure 3 represents the 11kV distribution network with embedded SG.

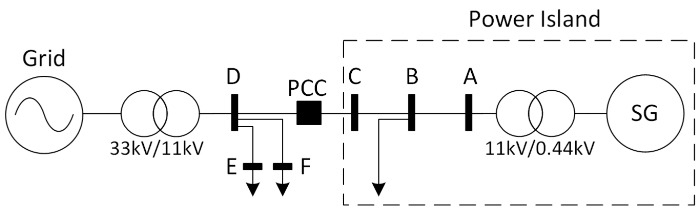

Figure 3: 11kV Power Network integrating SG

Case Study 2:
At this case a SG and PV have been connected to the distribution network. Under this case, 2 different scenarios have been taken into consideration. The first one sets the SG to have a portion of 75% of the total installed DG capacity of (2 MVA) while the PV contributes the remaining 25%. The second scenario considers equal portion of 50% from each generation technology. Figure 4 represents the 11kV distribution network integrating SG and PV.

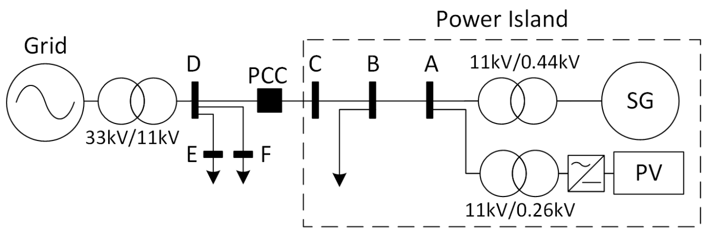

Figure 4: 11kV Power Network integrating SG and PV

Case Study 3:
This particular case study considers two inverter connected generators, PV and DFIG. For this case study two different scenarios have been considered. The first one introduces the PV to have a rating of 75% of the total DG's installed capacity while DFIG holds the 25%. The second scenario considers equal portion of 50% from each technology. Figure 5 represents the 11kV distribution network integrating PV and DFIG.

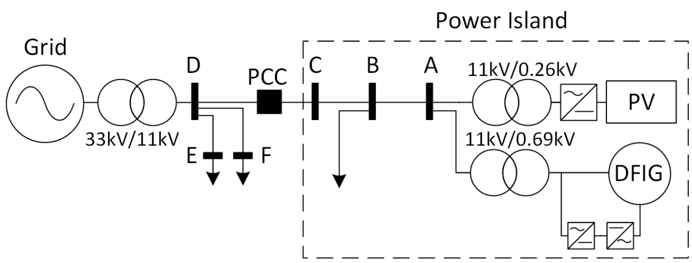

Figure 5: 11kV Power Network integrating PV and DFIG

V. NDZ Assessment

The NDZ had been determined for both active and reactive power import at the PCC. The imbalance of one type of power was changed while holding the other type of power imbalance at 0% by adjusting the local demand. Table 2 summarizes the NDZ values for study case study 1 and 2. The NDZ values are shown for power import across the PCC prior to LOM event. The results presented in table 2 are also depicted in figures 6 - 11, separately for active and reactive power. NDZ for case study 3 could not be assessed due to the specific nature of the interaction which has been observed when simulating PV and DFIG technologies in an islanded situation. Further analysis and discussion of this specific case is included in section VI. A set of waveforms for case study 3, including system frequency, RoCoF and voltage, are presented in figures 12 to 15

	Case Study: 1		**Case Study: 2**			
	SG		**SG - PV [75% - 25%]**		**SG - PV [50% - 50%]**	
Setting Option	**NDZ_P [%]**	**NDZ_Q [%]**	**NDZ_P [%]**	**NDZ_Q [%]**	**NDZ_P [%]**	**NDZ_Q [%]**
1	0.86	2.24	1	0.89	0.4	0.3
2	0.96	2.65	1.4	1.45	0.42	0.4
3	1.11	6.35	2.34	19.95	1.67	12.4
4	3.06	10.8	3.6	20.5	2.9	14.38
5	5.86	21.58	5.90	24.28	4.56	20

Table 2: NDZ results for case study 1 and 2

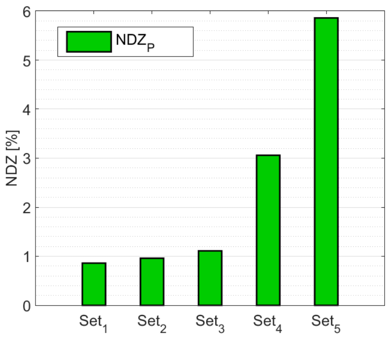

Figure 6: SG NDZ for Active Power

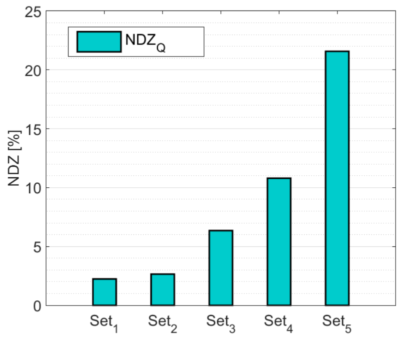

Figure 7: SG NDZ for Reactive Power

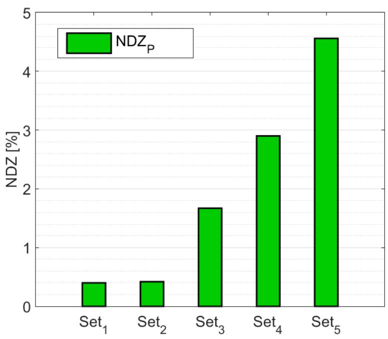

Figure 8: SG-PV NDZ for Active Power(SG: 50%, PV: 50%)

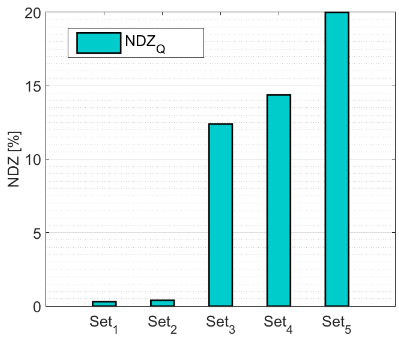

Figure 9: SG-PV NDZ for Reactive Power (SG: 50%, PV: 50%)

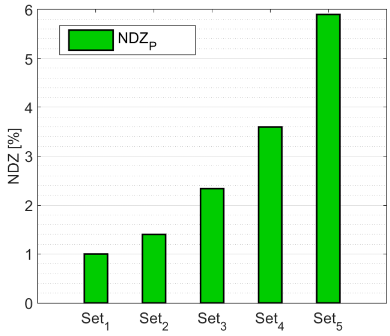

Figure 10: SG-PV NDZ for Active Power (SG: 75%, PV: 25%)

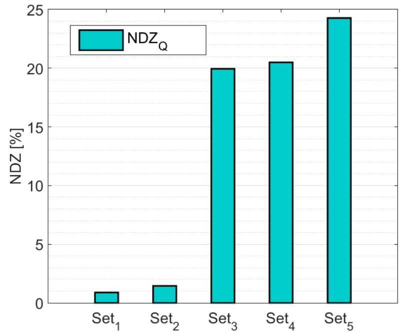

Figure 11: SG-PV NDZ for Reactive Power (SG: 75%, PV: 25%)

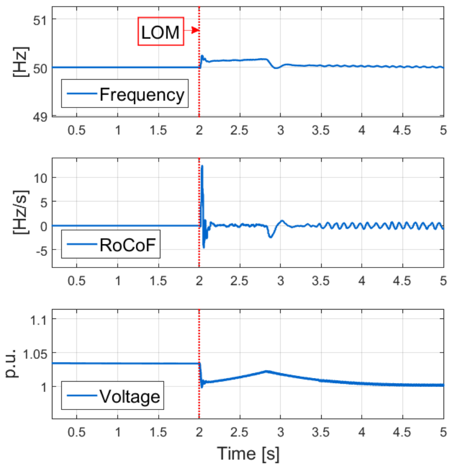

Figure 12: Frequency, RoCoF and voltage waveforms for 5% active power imbalance at PCC, for case study 3 (PV: 75%, DFIG: 25%)

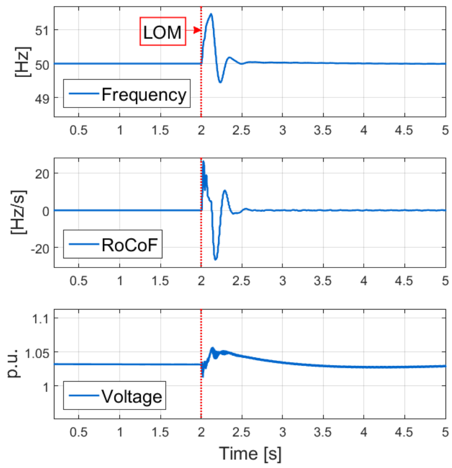

Figure 13: Frequency, RoCoF and voltage waveforms for 5% reactive power imbalance at PCC, for case study 3 (PV: 75%, DFIG: 25%)

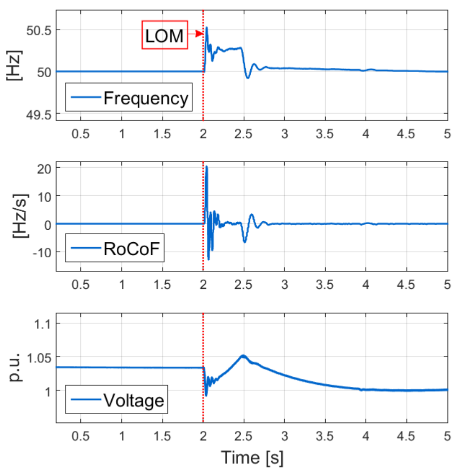

Figure 14: Frequency, RoCoF and voltage waveforms for 5% active power imbalance at PCC, for case study 3 (PV: 50%, DFIG: 50%)

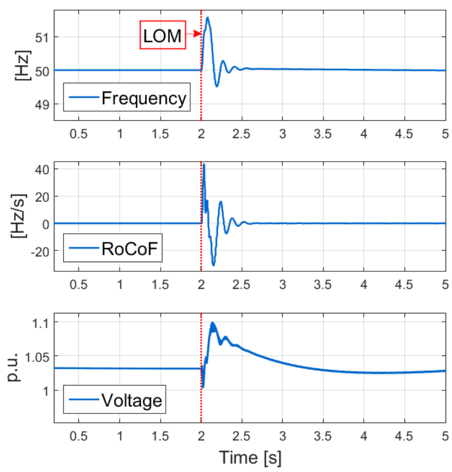

Figure 15: Frequency, RoCoF and voltage waveforms for 5% reactive power imbalance at PCC, for case study 3 (PV: 50%, DFIG: 50%)

VI. Discussion

From the results included in Table 1 it can be observed that generally, as expected, with increasing value of ROCOF setting as well as with additional time delay the NDZ becomes wider. For example, in case study 1 the highest NDZ value is reached for setting option 5 which corresponds to 1.0 Hz/s with a time delay of 0.5 seconds. The NDZ for setting options 1, 2, and 3 are really close with each other, especially for active power. Since setting option 3 has a relatively low NDZ (almost the same with settings 1 and 2), while there is a time delay of 0.5 seconds, it could be said that it forms a good setting selection. This is due to the fact that the time delay could make the system more stable especially for external faults, but also for transients accompanied with reduced system inertia. It is worth saying there that the NDZ value for reactive power can vary significantly according to the excitation system and the control strategy used. At this case a standard iEEE type 1 with standard P-V control was used.

For study case 2 a SG and a PV have been considered. It can be noted here that as the portion of inverted connected generation increases the NDZ decreases. This is due to the fact that the generation mix contains less SG, hence the system inertia is reduced which leads to a more unstable islanded operation. During simulation analysis it has been noted that total instability occurs when PV forms 70% of the total DG capacity. At this point the ROCOF based protection becomes unreliable as the frequency response (hence RoCOF) drifts into an oscillatory situation. In particular, for setting options with no time delay, the ROCOF relay trips instantaneously even for 0% power imbalance (NDZ=0%). However, when the time delay is used (setting options 3, 4, and 5), due to the oscillatory response at DG terminals, no tripping signal could be achieved even at high power imbalance scenarios (i.e. very wide NDZ). The generator in such cases would be disconnected either by voltage or frequency protection.

In case study 3 a PV and a DFIG have been used. For ROCOF protection the NDZ could not be assessed with these particular generation technologies, and the selected control strategies. The system seems to be quite stable for constant impedance loads. During the islanding, when the connection with the grid is lost, a voltage drop at the DG terminal occurs which has a stabilising effect. As the load is represented by a constant impedance, its power adjusts according to the square of the voltage and the system reaches a new steady state condition. This is achieved after a small transient in voltage magnitude and frequency. Figures 12 to 15 represent frequency, ROCOF and voltage waveforms for 5% active and reactive power imbalance. During simulation analysis RoCoF tripping took place only for the first two setting options, where there is no time delay, even for 0 % power imbalance. However when time time delay was introduced there was no RoCoF tripping. Similarly to case study 2, for high power imbalances across the PCC G59 Under-Voltage and Under-Frequency protection would initiate a tripping signal [14].

Simulation studies showed that the NDZ varies significantly with the generator technology, control strategy and the portion of each generator within the whole generation mix capacity. Moreover the load model can affect the system response and hence the NDZ. In this paper, NDZ results have been presented only for constant impedance loads. Further studies will be published including more generation technologies, load mix including constant power and constant impedance, and different control strategies especially for SG excitation system.

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