Grid code compatible islanding detection schemes using traditional passive methods

H. Laaksonen*

**ABB Oy, Vaasa, Finland, hannu.laaksonen@fi.abb.com*

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Abstract

The focus in this paper is on development of voltage vector shift (VVS) based passive islanding detection as a part of grid code compatible combined islanding detection scheme or alone as a back-up for combined scheme. Islanding detection during utility grid frequency fluctuations could be made more reliable and also non-detection zone (NDZ) could be reduced with VVS based combined scheme if sensitive settings / more sensitive determination of VVS are used. In addition, one possible solution to prevent VVS maloperation during utility grid frequency disturbances, when VVS is used alone, will be presented. Proposed new schemes and solutions, their benefits, suitable settings etc. will be demonstrated and justified with PSCAD simulations from healthy/faulty islanding cases as well as from different non-islanding events using synchronous, induction and doubly-fed induction generator (DFIG) based DG unit models.

1 Introduction

In following, at first possible effects of new grid code requirements on future islanding detection schemes will be presented and after that some issues related to VVS algorithm implementation will be shortly reviewed.

1.1 Grid code requirements and islanding detection schemes

Traditionally techniques proposed for islanding detection have been divided into two categories: 1) communication-based, like transfer trip schemes and 2) local detection-based, active and passive methods. Local methods have also usually been dependent from the DG unit type, unlike the communication-based methods. More recently also hybrid and combined islanding detection methods have been proposed and are used in some countries.

The major challenges with distributed generation (DG) traditional passive islanding detection methods like frequency (*f*), rate-of-change-of-frequency (ROCOF, *df/dt*), voltage (*U*) or voltage vector shift (VVS) have been NDZ near a power balance situation and nuisance tripping / maloperation due to other network events like, for example, utility grid fault, parallel MV feeder fault or capacitor connection.

In the future, the use of *f*, *U* and ROCOF (*df/dt*) for defining DG units' fault-ride-through (FRT) requirements in the new grid codes will increase (Fig. 1). DG unit grid code requirements like the active power/frequency (*P/f*)- or *Q/U*-control may also stabilize island if operation time delays are not coordinated with *U*, *f*, *df/dt* or VVS (Fig. 1). In general, it is expected that when the number of DG units increases and power balance situations can happen more frequently, the high-speed communication based transfer trip schemes will be increasingly used as a primary islanding detection method. However, in Europe in ENTSO-E grid code Requirements for Generators (RfG) [1] it has been stated that islanding detection should not be based only on network operator's switchgear position signals (Fig. 1).

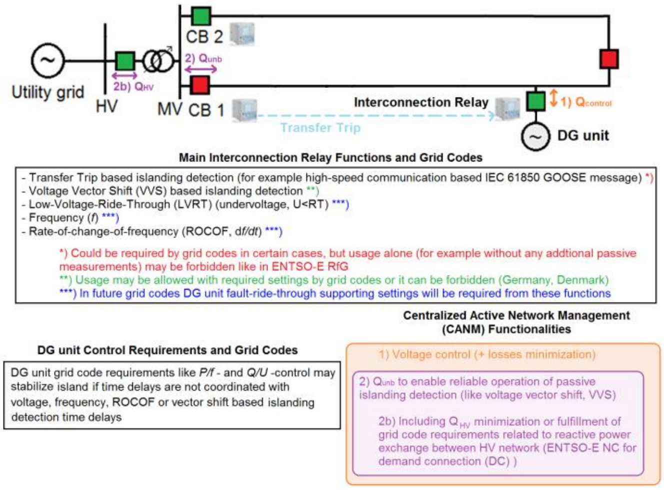

Figure 1: Grid code requirements and future islanding detection schemes.

Based on above, in the future, the use of only the traditional local parameters like *f*, *df/dt* and *U* for reliable and selective islanding detection becomes more difficult than it is today and new combined (transfer trip + passive, Fig. 2) as well as possible new local passive islanding detection schemes are needed. Also, as presented in [2] and [3], centralized active network management functionality (CANM) at MV level could continuously control the reactive power unbalance Q_{unb} over circuit-breakers which could potentially create an island (Fig. 2), so that the operation point would constantly remain outside the NDZ of the VVS algorithm (or some other passive islanding detection method) and therefore high-speed communication based transfer trip would not be needed to be able to minimize NDZ. Different possible future grid code compatible islanding detection schemes using VVS have been presented in Fig. 2.

Islanding Detection Schemes using Traditional Passive Methods

1.	High-speed communication based Transfer trip x) & Fault Detection/Direction xx) + Traditional Passive Method (VVS) + CANM
2.	High-speed communication based Transfer trip x) & Fault Detection/Direction xx) + Traditional Passive Method (VVS)
3.	Traditional Passive Method (VVS) + CANM
4.	Traditional Passive Method (VVS)

x) From opened CB

xx) No fault/fault and upstream/downstream fault information from opened CB

	Non-detection zone (NDZ)	Nuisance tripping / maloperation	Need for active network management (reactive power flow Q_{unb} control)
1.	NO	NO	Very small *)
2.	Very small *)	NO	NO
3.	NO	Small **) - Moderate ***)	Small *) - Moderate
4.	Moderate *) - Larger	Small **) - Moderate ***)	NO

*) If sensitive settings / more sensitive determination of VVS is used

**) If undervoltage blocking is used with VVS (and *)), utility grid frequency fluctuations still challenging with VVS

***) If undervoltage blocking is NOT used with VVS (and *)), utility grid frequency fluctuations still challenging with VVS and less sensitive settings / determination of VVS should be used to reduce the amount of nuisance tripping

Figure 2: Different possible future grid code compatible islanding detection schemes using VVS.

In this paper combined scheme (high-speed communication based transfer trip, like IEC 61850-based GOOSE message & fault detection/direction + VVS) using VVS with sensitive setting (for example 2°) and without under-/overvoltage blocking, as shown in Fig. 3, is considered as primary islanding detection method and VVS alone with under-/overvoltage blocking and wider settings (for example 6°) as a back-up method (Fig. 3). Due to sensitive VVS setting used in combined scheme (Fig. 3) smaller NDZ can be achieved and risk of maloperation due to other network events is small because combined criteria is used. Regarding Fig. 1 and 3 as well as above mentioned ENTSO-E RfG requirement it could be stated that only transfer trip & fault detection/direction could be enough alone to fulfil ENTSO-E RfG requirement. However, when islanding intentionally without fault (due to maintenance break or due to signal from DMS or MMS/Microgrid controller) some other passive parameter like VVS in addition to CB status signal will be required.

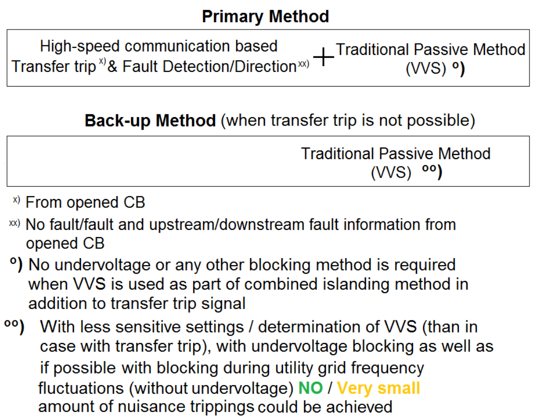

Figure 3: Primary (combined) and back-up (only VVS) islanding detection schemes using VVS.

1.2 VVS algorithm implementation

VVS is still used for islanding detection in many countries, although Germany and Denmark have forbidden its use due to its sensitivity to nuisance tripping. As stated in [4], the principle of VVS is simple but the actual performance of a VVS function depends on how the algorithm has been implemented. In [4] VVS algorithms used in different relays were compared and results revealed considerable variations. For example some manufacturers use a reference based on the average duration of a number of previous (between 5 and 32) cycles [4]. Some other compares all three phase voltage angles every half-cycle and the trip decision is made after every full cycle by comparing the angle differences between the present and previous cycle [5]. If 5 of those 6 results (2 half-cycles x 3 phase voltages) are above the setting, a trip signal is sent [5].

In order to reduce the number of VVS maloperation due to other network events use of all three phases for VVS detection is recommended instead of single phase VVS operation [6]. In reference [4] it was stated that typical settings for VVS are between 6° and 12°.

In this paper more sensitive VVS determination means DFT angle difference over 2 cycles (40ms in 50 Hz) as also presented in [7] and less sensitive determination of VVS means DFT angle difference average over 2 cycles. The effects of these different VVS determinations will be also studied in the following simulations. When VVS is used alone, under-/overvoltage blocking is used with VVS like shown in [7] to reduce the amount of VVS nuisance tripping due to short-circuit faults. In this paper VVS behavior based on positive sequence voltage U_1 changes will be investigated by simulations. Also suitable settings for VVS under-/overvoltage blocking will be determined based on simulation results.

2 Simulations

In this section PSCAD simulation results from non-islanding, islanding (no fault before islanding) and islanding (fault before islanding) cases with different type of DG units (synchronous generator SG, asynchronous generator ASG and doubly-fed induction generator DFIG) will be presented. In all simulated cases SG inertia constant was 0.7 s and ASG inertia constant was 2.24 s. Simulated radial MV network consisted of two 10 km long MV feeders and DG unit is connected 6 km from the beginning of the other MV feeder. Load in islanding simulations was chosen to be mainly constant impedance based as also recommended in [8].

2.1 Non-islanding events

Following non-islanding events were simulated.

a. Capacitor (1.5 MVAr) connection at HV/MV substation MV busbar
b. First utility grid under-frequency variation (min. value 49.5 Hz)
c. Second under-frequency variation (min. value 49.2 Hz) (t = 7 - 8.5 s)
d. Parallel main transformer disconnection at HV/MV substation
e. Parallel main transformer re-connection at HV/MV substation
f. Large utility grid voltage dip (100 ms from 1.0 to 0.15 pu) (t = 10.5 s)
g. 3-phase fault (100 ms) at HV/MV substation MV busbar (t = 13.5 s)
h. 3-ph fault (100 ms) at the beginning of parallel MV feeder (t = 16.5 s)

Primary Method (Combined)

Islanding detection false/maloperation is not a problem with combined method (transfer trip & fault detection + VVS without internal blockings and with sensitive setting) because transfer trip signal (after CB opening/status change) will not be sent in any of the studied non-islanding events.

Back-up method (only VVS)

In general the most challenging non-islanding events for VVS when it is used alone were b, c, g and h which can be seen from Fig. 4 simulation results with SG based DG unit.

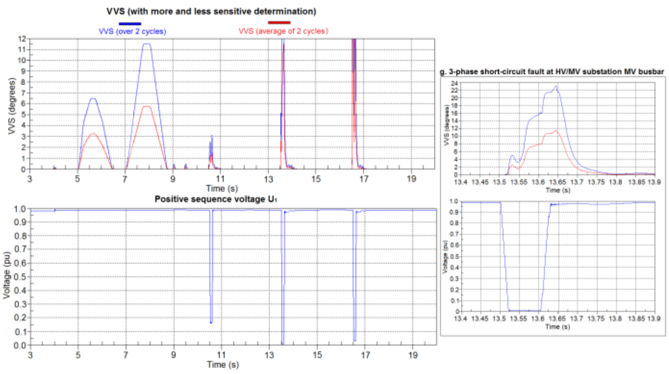

Figure 4: Behavior of VVS with more and less sensitive determination as well as behavior of U_1 in non-islanding events with SG based DG unit.

VVS operation in utility grid frequency variations (b and c) was not dependent on type of DG unit. In both cases (b and c) with 6° setting VVS will maloperate with all type of DG units if the calculation of VVS is based on more sensitive determination (Fig. 4). If calculation of VVS is based on less sensitive determination then VVS will not maloperate with 6° degree setting (Fig. 4). However, if higher VVS setting is used, like 12°, then VVS will not maloperate even with more sensitive determination of VVS (Fig. 4).

VVS behavior in 3-phase short-circuit faults (g and h) was to some extent dependent on the network parameters as well as on the DG unit type so that with ASG and DFIG higher VVS values were seen. Without U_1 undervoltage blocking maloperation of VVS would have been seen in most cases with 6° and also with 12° setting with both more and less sensitive VVS determination (Fig. 4). Based on simulations suitable value for VVS U_1 based undervoltage blocking in events f, g and h could have been for example 0.3 pu. When only VVS is used, the possibility of VVS maloperation in removing 3-phase faults (Fig. 4) should be taken into account by long enough internal blocking (at least 100-200 ms i.e. after undervoltage has disappeared) even if VVS value drops below start value before this internal undervoltage blocking is over.

2.2 Islanding – No fault before islanding

In this section PSCAD simulation results from different islanding cases (with different amount of power unbalance and with different type of DG units) without fault before islanding are shown when VVS is used as part of combined method as well as when VVS is alone.

Primary Method (Combined) – VVS setting 2°

In Table 1 the simulation results (start time delays) for VVS based islanding detection with 2° setting and with more / less sensitive VVS determination are presented when VVS is used as part of combined (Fig. 3) method.

DG unit type	*Power unbalance before islanding (over PCC CB)*		*DG unit active and reactive power before islanding*		*Start with 2° setting (time delay after islanding) [ms]*	
	P_{unb} [kW]	*Q_{unb} [kVAr]*	*P_{DG} [kW]*	*Q_{DG} [kVAr]*	*VVS (over 2 cycles)*	*VVS (average over 2 cycles)*
SG	0	100	1165	-10	95	150
	0	-100	1165	-210	105	160
	0	250	1165	140	40	80
	0	-250	1165	-360	45	80
	-700	385	465	270	20	25
ASG	0	70	630	-130	210	330
	0	-130	630	-200	100	222
	0	140	630	-60	145	246
	0	-240	630	-200	45	125
	-750	-165	630	-200	20	27
DFIG	0	100	1020	120	40	50
	0	-100	1020	-80	39	49
	-720	-405	1020	20	43	50

Table 1: Start time delays of VVS based islanding detection with 2° setting and with more / less sensitive VVS determination when VVS is used as part of combined (Fig. 3) method.

Back-up method (only VVS) – VVS setting 6°

In Table 2 the start time delays of VVS based islanding detection with 6° setting and with more / less sensitive VVS determination and positive sequence voltage U_1 values when VVS is used alone (Fig. 3) are shown.

DG unit type	*Power unbalance before islanding (over PCC CB)*		*Start with 6° setting (time delay after islanding) [ms]*		*Positive sequence voltage U_1 (10 ms after start of VVS) [pu]*	
	P_{unb} [kW]	*Q_{unb} [kVAr]*	*VVS (over 2 cycles)*	*VVS (average over 2 cycles)*	*VVS (ov. 2 cycle)*	*VVS (aver. over 2 cycles)*
SG	0	100	190	400	1.025	0.975
	0	250	118	177	1.103	1.088
	0	440	77	136	1.155	1.158
	0	-600	62	98	0.660	0.580
	-700	-220	42	97	0.950	0.930
ASG	0	70	415	670	1.178	1.164
	0	-130	280	445	0.580	0.445
	0	140	330	550	1.204	1.190
	0	-240	191	330	0.510	0.318
	-750	-165	33	46	0.710	0.680
DFIG	0	-100	58	382	1.010	1.101
	0	-200	47	63	0.980	1.110
	-720	-405	55	66	0.590	0.680

Table 2: Start time delays of VVS based islanding detection with 6° setting and with more / less sensitive VVS determination and value of U_1 when VVS is used alone (Fig. 3).

It can be seen from Table 1 simulation results that already with ± 150 kVAr reactive power unbalance before islanding less than 150 ms islanding detection times (VVS start time delays) can be achieved with more sensitive VVS determination (difference over 2 cycles) with all type of DG units when 2° setting is used. With DFIG and SG based DG units even much shorter detection times can be achieved (Table 1) with even smaller reactive power unbalance Q_{unb}. Also in general with less sensitive VVS determination (average over 2 cycles) the detection times are longer in every case (Table 1). Because combined method does not need to use U_1 for internal blocking of VVS, the U_1 values are not presented in Table 1.

Table 2 simulation results show that islanding detection times (VVS start time delays) are a bit longer than in Table 1 when VVS is used alone with 6° setting, but especially with DFIG based DG unit and with more sensitive VVS determination the difference is not very large. Suitable settings for VVS internal under- and overvoltage blocking values when VVS is used alone with 6° setting are dependent on the DG unit type, DG unit active and reactive power as well as on power unbalance (P_{unb}, Q_{unb}) before islanding when there is no fault before islanding. However, with undervoltage setting 0.30 pu and overvoltage setting 1.3 pu any islanding case without fault before islanding should not be blocked even with less sensitive VVS determination (Table 2) with VVS setting 6°.

2.3 Islanding – Fault before islanding

In this section, the simulation results from different islanding cases with fault before islanding (healthy and faulty islanding cases depending on the location of the fault i.e. inside or outside islanded part of the network) are shown when VVS is used as part of combined method as well as when VVS is alone.

Primary Method (Combined)

Based on the simulation results the combined islanding detection method (Fig. 3) can separate healthy islanding after parallel MV feeder/upstream 3-phase fault from removing 3-phase fault (Fig. 4). However, even with combined method ASG based DG unit will be disconnected based on the LVRT curve after 'healthy islanding' (see Fig. 5a). This will happen if LVRT curve is not blocked after 'healthy' islanding detection, because the voltage recovery does not happen fast enough if there is only ASG based DG unit in the islanded part of the network (Fig. 5a).

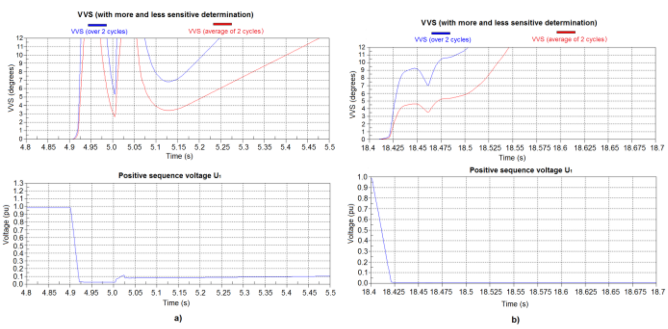

Figure 5: Behavior of VVS with more and less sensitive determination as well as behavior of U_1 a) in healthy islanding (at t = 5.0 s) after parallel MV feeder 3-phase fault (at t = 4.9 s) with ASG based DG unit (P_{unb}=0 kW, Q_{unb}=0 kVAr) and b) in faulty islanding (at t = 18.5 s) 100 ms after same MV feeder 3-phase fault with SG based DG unit (P_{unb}=0 kW, Q_{unb}=0 kVAr).

In general, the fault current direction detection as part of combined method (Fig. 3) is useful for separating healthy and faulty islanding cases more reliably. In case of faulty islanding (Fig. 5b) it is also beneficial to use VVS with sensitive setting/determination without internal under-/overvoltage blocking as part of combined scheme (Fig. 3). Otherwise VVS could be blocked and islanding not detected and DG unit would be disconnected according to its LVRT curve (similarly to a case where only VVS is used), but this may not be always compatible with auto-reclosing practices and therefore fast islanding detection before LVRT operation is preferred.

Back-up method (only VVS)

As stated in section 2.1, when VVS is used alone, possibility of maloperation of VVS in removing 3-phase faults should be taken into account by long enough internal blocking, for example 100-200 ms after voltage has recovered i.e. risen above chosen undervoltage blocking limit. In the following simulation results (Fig. 6 and Table 3) only VVS is used alone and based on sections 2.1 and 2.2 chosen undervoltage blocking value is 0.3 pu. In case of healthy islanding after 3-phase fault on parallel MV feeder, the possible operate time is calculated with SG (Fig. 6) and DFIG based DG units with 6° setting so that it is assumed that internal VVS undervoltage blocking continues 100 ms after voltage has risen over chosen undervoltage blocking value 0.3 pu to be able to prevent maloperation in removing 3-phase faults (Table 3). As previously presented in Fig. 5a, ASG based DG unit will be disconnected based on LVRT curve (Table 3) also after healthy islanding after 3-phase fault, because undervoltage blocking continues after islanding. In addition, in case of faulty islanding after 3-phase fault when VVS is used alone, islanding cannot be detected and all type of DG units will be disconnected based on their LVRT curves (Table 3) because undervoltage blocking also continues after islanding (see for example 5b).

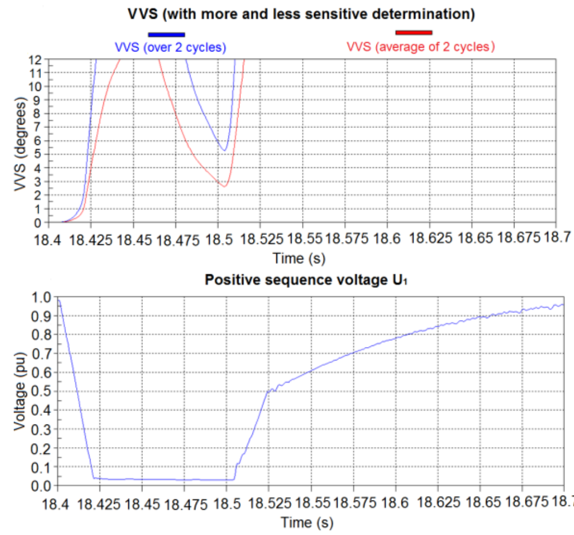

Figure 6: Behavior of VVS with more and less sensitive determination as well as behavior of U_1 in healthy islanding (at t = 18.5 s) after parallel MV feeder 3-phase fault (at t = 18.4 s) with SG based DG unit (P_{unb}=0 kW, Q_{unb}=100 kVAr, Table 3).

DG unit type	Location of 100 ms 3-phase fault before islanding, inside island (YES or NO)	Power unbalance before islanding (over PCC CB)		Start time with 6º setting (time delay after islanding if internal blocking continues 100 ms after voltage recovery over 0.3 pu) [ms]	
		P_{unb} [kW]	Q_{unb} [kVAr]	VVS (over 2 cycles)	VVS (aver. over 2 cycles)
SG	NO	0	0	118	118
	NO	0	100	118	118
	YES	0	250	- (LVRT)	- (LVRT)
ASG	NO	0	0	- (LVRT)	- (LVRT)
	NO	0	70	- (LVRT)	- (LVRT)
	NO	0	-130	- (LVRT)	- (LVRT)
	YES	0	0	- (LVRT)	- (LVRT)
DFIG	NO	0	0	207	207
	NO	0	100	117	117
	NO	0	-100	117	117
	YES	0	0	- (LVRT)	- (LVRT)

Table 3: Start time delays of VVS based islanding detection (if internal blocking continues 100 ms after voltage recovery over 0.3 pu) with 6° setting and with more / less sensitive VVS determination after healthy/faulty islanding (after 100 ms 3-phase fault) when only VVS is used.

In case of 1-phase fault on the same feeder before faulty islanding internal undervoltage blocking based on U_1 (or U_{ab}, U_{bc}, U_{ca}) will not be activated and faulty island can be detected with VVS only. However, based on simulations the overvoltage blocking limit needs to be high enough i.e. at least 1.3 pu to prevent overvoltage blocking after healthy islanding especially when DFIG based DG unit and only VVS alone is used. As seen from Table 3, the simulation results of SG and DFIG based DG units show that the operation times in case of healthy islanding after 3-phase fault are not necessarily dependent on power unbalance before fault & islanding and the differences of operation times between more and less sensitive VVS determination are negligible in these cases.

2.4 VVS settings

In general, as a conclusion from simulation results presented in sections 2.1-2.3, it can be stated that with combined method it is beneficial to use sensitive setting (could be also smaller than 2°, e.g. 1°, to enable faster islanding detection with ASG and SG based DG units) with more sensitive VVS determination (as presented in [7]) to be able to achieve rapid and reliable islanding detection.

Similarly when VVS is used alone it is more beneficial to use more sensitive VVS determination to be able to achieve more rapid islanding detection in most of the situations. In addition, quite sensitive setting (like 6°) without VVS maloperation (except in utility grid frequency variations) can be used if appropriate internal under-/overvoltage blocking limits are used. Based on simulations suitable undervoltage blocking limit could be 0.3 pu and respectively overvoltage limit 1.3 pu. As also stated in section 2.1, when VVS is used alone, the possibility of maloperation of VVS in removing 3-phase faults should be taken into account by long enough internal blocking (for example 100-200 ms) after voltage has risen above undervoltage blocking limit (0.3 pu) even if VVS value drops below start value before this. The start/operate of VVS is again possible only 100-200 ms after internal undervoltage blocking removal (100 ms in Table 3 results).

3 Possibilities to improve VVS operation

Possible new ways to improve VVS operation, especially when VVS is used alone, will be presented in the following.

Based on simulation results presented in section 2, there are still certain cases in which VVS cannot operate correctly (prevent maloperation in non-islanding events or detect islanding) when it is used alone (Fig. 3). These cases were utility grid frequency variations (non-islanding event, section 2.1) and detection of faulty islanding after 3-phase fault on the same MV feeder (section 2.3).

In order to avoid maloperation in smaller utility grid frequency variations it could be more beneficial to use less sensitive VVS determination. However, then sensitivity in real islanding cases (without fault before islanding) would be decreased. On the other hand, the VVS setting (start value) could be increased if more sensitive setting is used to prevent maloperation in smaller utility grid frequency variations, but also in this case the sensitivity of the islanding detection will be decreased and NDZ increased. Therefore one possibility to prevent VVS maloperation and DG unit nuisance tripping during utility grid frequency disturbances could be adaptive VVS in certain frequency range with chosen steps based on measured FFT frequency. The principle of adaptive VVS in frequency range 50.0 ± 1.0 Hz is presented in Fig. 7a. In Fig. 7b behavior of adaptive VVS in utility grid frequency variation (Fig. 7c) is presented together with more and less sensitive VVS.

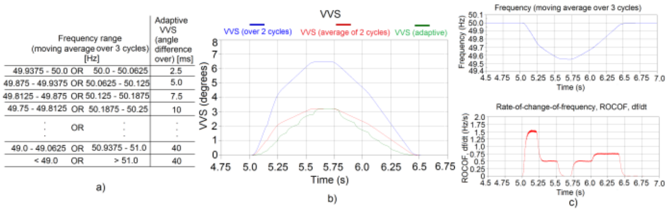

Figure 7: a) Principle of adaptive VVS in frequency range 50.0 ± 1.0 Hz, b) behavior of adaptive VVS as well as VVS with more and less sensitive determination during utility grid frequency variation (t = 5.0 - 6.5 s) and c) simultaneous behavior of frequency and rate-of-change-of-frequency (ROCOF, df/dt).

Fig. 7b shows that it is more likely that possible grid code DG unit frequency and ROCOF FRT requirements can be fulfilled without unnecessarily disconnecting DG unit due to VVS false islanding detection with adaptive VVS than with more sensitive VVS determination (depending on the VVS setting). However, adaptive VVS may delay detection of real islanding cases when compared to more sensitive VVS determination. The start time delays of VVS based islanding detection with 6° setting and with adaptive VVS (Fig. 7a) and positive sequence voltage U_1 values when VVS is used alone are presented in Table 4.

DG unit type	Power unbalance before islanding (over PCC CB)		Start with 6° setting (time delay after islanding) [ms]	Positive sequence voltage U_1 (10 ms after start of VVS) [pu]
	P_{unb} [kW]	Q_{unb} [kVAr]	VVS (adaptive)	VVS (adaptive)
SG	0	100	295	0.996
	0	-100	305	0.961
	0	440	130	1.155
	0	-600	94	0.570
ASG	0	140	460	1.201
	0	-240	285	0.379
	-750	-165	50	0.649

Table 4: Start time delays of VVS based islanding detection with 6° setting and with adaptive VVS (Fig. 7a) and value of U_1 when VVS is used alone.

When Table 4 results are compared to Table 2, it can be seen that in almost all cases the adaptive VVS start time with 6° setting (Table 4) is between start times of more and less sensitive VVS (Table 2). This means that adaptive VVS operation is slower than with more sensitive VVS, but usually faster than with less sensitive VVS.

Grid codes may require different kind of frequency FRT capabilities from DG units as presented in [9]. Therefore in order to ensure correct operation of VVS with off-nominal frequencies the calculation of VVS and correction angle should be done as shown in Fig. 8 instead of what was presented in [7]. Calculation of correction angle (Fig. 8) should be changed to make VVS work with off-nominal frequencies, for example 50 ± 2.5 Hz, based on comparison of measured frequency to 100 cycles old, stable/steady-state frequency (which means in 50 Hz system 2 second old frequency) so that sensitivity to detect islanding is not affected. This slow 'adaptation' to off-nominal steady-state frequency is even more important with more sensitive VVS than with less sensitive VVS.

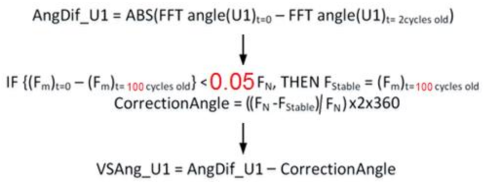

Figure 8: Principle of VVS (VSAng_U1) and correction angle calculation to ensure correct operation with off-nominal frequencies (for example in frequency range 50 ± 2.5 Hz).

4 Conclusions

In this paper, the grid-code compatible combined scheme using VVS with sensitive setting (1° - 2°) and without under-/overvoltage blocking (Fig. 3) was considered as primary islanding detection method and VVS alone with under-/overvoltage blocking and wider settings as a back-up method (Fig. 3). When passive islanding detection method like VVS is used alone (as a back-up) conflicts with voltage *U* (LVRT), frequency *f* and *df/dt* FRT requirements are possible. From DG unit FRT ability point of view blocking of VVS based islanding detection from FRT functions could be possible to prevent VVS operation before LVRT (*U*), *f* and/or *df/dt* operation. On the other hand, from the islanding detection point of view the prioritization of VVS based islanding detection method with DG unit FRT requirements (*f*, *df/dt* and *U*) may be required especially when the primary method (combined or new multi-criteria based passive [9], Fig. 9) cannot be used, for example so that VVS operation is allowed before LVRT (*U*), *f* and/or *df/dt* operation while it is used as a back-up method. In addition, prioritization between *U*, *f* and *df/dt* based FRT requirements may be required. For example, the current Finnish grid code does not allow DG unit disconnection when *df/dt* FRT upper limit 2 Hz/s is exceeded if LVRT function has started [9].

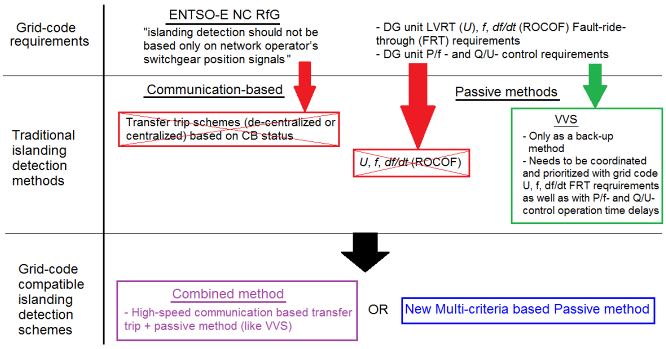

Figure 9: Grid code compatible islanding detection schemes.

In further studies it could be also checked that is it possible/feasible to find a setting for VVS (when used alone as a back-up) and how high the setting would need to be to enable coordination/selectivity with *U*, *f* and *df/dt* requirements without need for blockings or prioritization as well as can operation time delays of *P/f*- and *Q/U*- functions be coordinated with VVS setting in a sensible way.

Acknowledgements

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