IMPACT OF VOLTAGE PHASE ANGLE CHANGES ON LOW-VOLTAGE RIDE-THROUGH PERFORMANCE OF DG-UNITS

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ABSTRACT

Based on computer simulations of a simplified radial 132, 66 and 22 kV system including a 5 MVA hydro power unit, it is concluded that the assessment of the unit's fault-ride-through (FRT) capability should be based not only on a voltage magnitude profile, but also on the change in the voltage phase angle. It is assumed that erroneous conclusions might be the result when FRT-capability studies are performed for distributed generation without taking into account the influence of the phase-angle change in this context. Further work will be conducted in order to quantify the effect of phase angle influence on the FRT capability of distributed generation units.

INTRODUCTION

Requirements regarding fault-ride-through (FRT) capability found in most of today's national grid codes apply to new generation which is planned for integration at either transmission system or regional grid level. Ref. [1] contains the grid codes for the Norwegian transmission system, prepared by Statnett, the Norwegian TSO. In some countries grid codes for integration of distributed generation (DG) units in the distribution grid already exist, see for instance [2] and [3]; while in other countries the preparation of such codes is in progress. ENTSO-E has prepared a draft network code intended for implementation in the EU countries [4]. This code contains requirements for generation units at all voltage levels.

The FRT capability requirements found in the various national grid codes are solely related to a specified transient voltage profile, i.e. the amplitude of the voltage, for which the generation units are required to maintain production without interruption or shut-down. The corresponding voltage phase angle change is not mentioned in any of the grid codes known to the authors of this paper. Manufacturers of renewable energy sources like wind turbine generators, will have to prove the FRT capability of their units through real-life tests before permission for grid connection is given, either on-site or at the manufacturers' own test sites. In the planning process of a given power plant development, however, the FRT capability for a given technology has to be analyzed via computer based modeling and simulations, in order to check whether the grid code requirements are met or not, and if not to establish a basis for improved solutions. IEC 51400-21 [5] suggests specified magnitudes, durations and shapes of voltage drops for validation of simulation models, and a test set-up for real-life testing of wind turbine responses to voltage dips. Voltage phase angle change is not mentioned in the standard.

A main question in this context is: how can the FRT-capability of a planned distributed generation unit (DG-unit) be tested via computer based simulations in the most effective way? Will it be necessary to apply a detailed model of the entire grid? Or is it sufficient to test only the generator model itself in a simplified grid model which covers the grid between the point of common coupling (PCC) and the DG-unit only, and applying the grid-code related FRT-curve as a disturbance to this model? In the latter case: should the disturbance be represented by the change in voltage amplitude only, or should also a change in the voltage phase angle be included in the assessment? The work of the present paper is a contribution to this discussion.

This paper presents results from a simulation study related to a grid model established for the purpose of the objective of this work. The model includes a hydro power DG-unit with a synchronous generator. The paper discusses the influence of certain grid faults on the dynamic behaviour of the generator, and how the change in amplitude and phase angle, respectively, of the generator's terminal voltage, will affect this behaviour, when these quantities are treated separately. The paper is organized as follows: In the following chapter the approach to the problem is explained. Next follows a description of the simulation model, including the generator, its excitation system, etc. Thereafter the various simulation cases and results are presented, together with result analysis. Finally a discussion and conclusions are given.

APPROACH TO THE PROBLEM

FRT requirements are normally expressed via a voltage borderline of a voltage profile describing a temporary drop in voltage at the network connection point in relation to time. An example of such a borderline profile is found in Figure 2.5.1.2-1 in [2]. The requirement related to the dynamics of the generating plant is as follows: if the voltage drops at values above the specified border lines, plants must not be disconnected from the grid. For voltage drops at values below the borderline (in the above figure in [2]) there are no specific requirements.

A FRT curve should represent the voltage dip experienced by a production unit when there is a fault somewhere in the grid. In this paper the responses of a DG-unit to a fault in the grid and to a voltage dip profile applied directly at the DG bus are compared. A grid fault creates a change in both voltage magnitude and voltage phase angle on the DG bus. The motivation for the work presented here is to investigate the possible impact of the voltage phase angle change on the DG response, and consequences of neglecting this impact in the FRT-curves.

The approach is to first apply a fault in the grid, and then make separate records of the voltage magnitude and the phase angle time series on the DG bus. The recorded time series are used as input to new simulations where the grid is replaced with a voltage source with controllable voltage magnitude and phase angle on the DG bus. In this way separate simulations with change only in voltage magnitude and only in voltage phase angle can be run, and corresponding DG-responses can be recorded.

SIMULATION MODEL

The system model under study is depicted in Figure 1. The system consists of a simple 132 and 66 kV radial regional grid, a 22 kV high voltage distribution grid and a 300 kV "stiff grid" (swing bus). There are two loads in the system, at BUS22_1 and BUS66_1, respectively. The loads are modeled as constant impedance loads. The synchronous generator is connected to the 22 kV grid via a 0.69/22 kV transformer. Data for lines, transformers, loads and generator are given in Appendices 1, 2, 3, and 4.

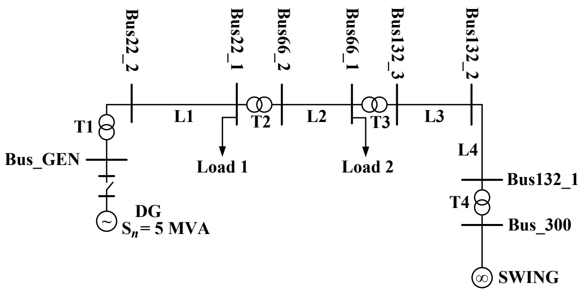

Figure 1. Single line diagram of system under study.

The synchronous generator model includes brushless excitation and an automatic voltage regulator. The excitation system model corresponds to model Type AC8B in Ref. [6]. Data for the excitation system are given in Appendix 5. The generator is operated with constant mechanical torque for all of the dynamic simulation cases studied, i.e. no turbine/governor model is included.

CASES AND RESULTS

The following three main cases have been defined for the present work:

Controlled change in bus voltage

In this case a controlled change in voltage amplitude on the system's swing bus is applied in order to emulate a specific grid-code related FRT-curve. (In principle this approach could have applied to any bus in the system). Assuming that all loads in the system are constant-impedance loads (resistive-inductive loads), this approach will not cause any change in the phase-angles throughout the system. The characteristics of the composite loads in a real power system will normally be different from those of constant-impedance loads. It is assumed, however, that this approach of applying change in in voltage amplitude only will not reflect real grid fault situations. Therefore this case will not be discussed further.

Earth fault with residual voltage

A 3-phase symmetrical fault is applied on BUS66_1 of the system model. The fault has a resistive character. The transition resistance of the fault has been adjusted to give a significant change in both amplitude and phase angle of the voltage throughout the system (towards the DG-unit). The fault clearing time is set at 250 ms in all simulations. This case is named Case 1 in the following. The next case, Case 2, implies that a 3-phase symmetrical fault is applied on BUS22_2 of the system under study. Besides the same comment apply as for Case 1.

The faults in Case 1 and Case 2 are applied one at a time. The generator is connected to the grid in these cases. The power production of the generator (S_N=5 MVA) is set at 4 MW and 0 Mvar for all cases. The AVR is operating in normal voltage-control mode. The fault is applied at t=1 s in the simulations.

Results

Modelling and simulations of the system under study have been performed in SIMPOW® [7]. Selected results from the dynamic simulations are given in the following figures.

Voltage amplitude and phase angle

The change in voltage amplitude in relation to time on the generator bus, Bus_GEN, as a result of the faults applied under Case1 and Case 2, respectively, is showed in Figure 2. The corresponding change in voltage phase angle is given in Figure 3.

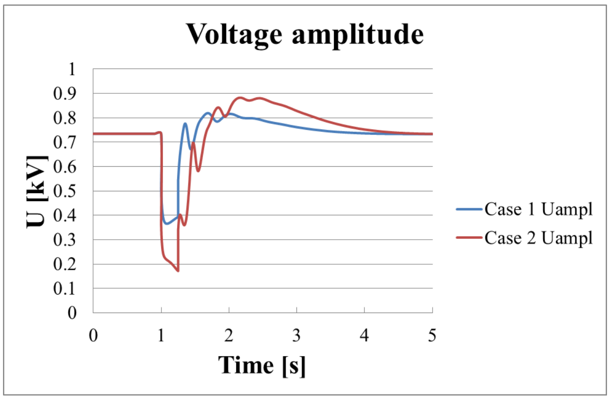

Figure 2. -Voltage amplitude on generator bus, Bus_GEN, in Cases 1 and 2. Temporary 3-phase fault at Bus66_1 and Bus22_2, respectively.

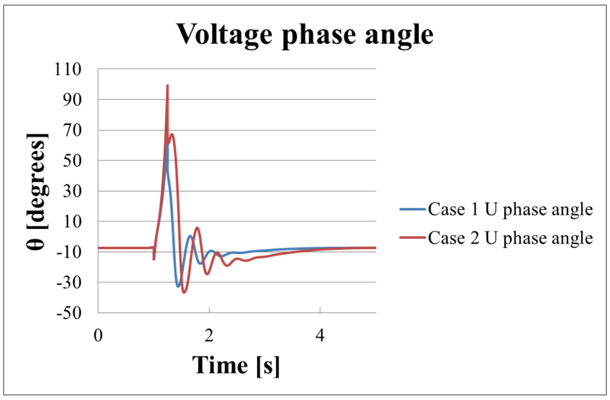

Figure 3. -Voltage phase angle on generator bus, Bus_GEN, in Cases 1 and 2. Temporary 3-phase fault at Bus66_1 and Bus22_2, respectively.

Besides the change in voltage amplitude, a significant change in the voltage phase angle can be observed from Figure 3 for these cases. This is in principle as expected.

Response in generator's active power
As described above, the transient responses of the DG-unit with regard to the applied faults have been studied as to active and reactive power, respectively. The response is simulated when the generator is connected into the the full grid model, and compared with the responses against change in voltage amplitude and phase angle, respectively, for the case where the generator model is connected to its local bus only. (The enforced changes in voltage amplitude and phase angle correspond to the results in Figures 2 og 3, respectively). The results regarding the generator's response in active power for these disturbances are depicted in Figure 4. The results apply for the above Case 2.

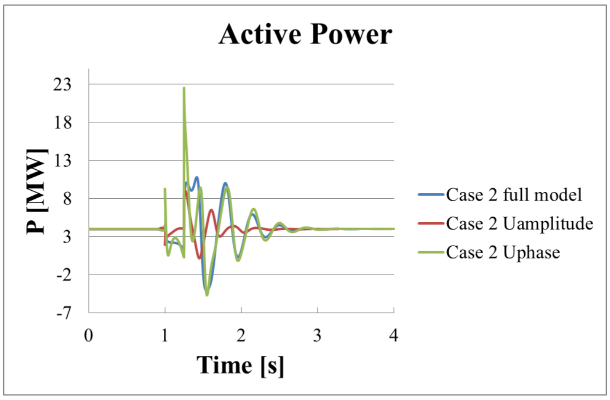

Figure 4 - Response in generator's active power for Case 2 (3-phase fault om Bus22_2).

From Figure 4 is observed a significant difference between the full model response in active power and the response obtained when only change in voltage amplitude makes the perturbation, as to the fault in question. This pattern is not observed between "full model" case and "phase angle" case.

Response in generator's reactive power
The generator's response in reactive power for the fault described in the above Case 2 and the disturbances given in Figures 3 and 4, respectively, are depicted in Figure 5.

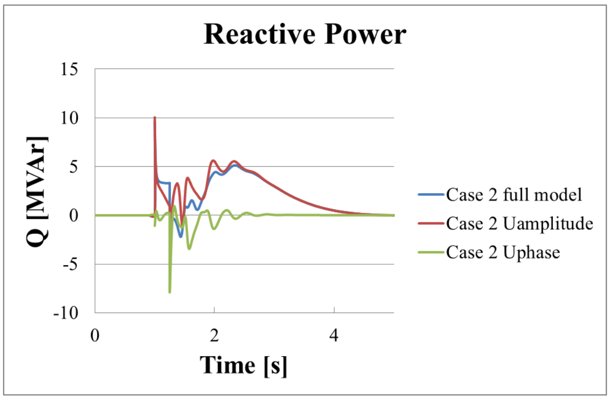

Figure 5. - Response in generator's reactive power for Case 2 (3-phase fault om Bus22_2).

A significant difference between the full model response in reactive power and the response obtained when only change in voltage phase angle is applied, is observed from Figure 5, as to the fault in question. Besides it can be observed that there is a (more or less) concurrent response between "full model" case and "amplitude" case, exept for the initial 600-700 ms after the fault inception.

DISCUSSION

The results obtained in the present work from dynamic computer based simulations of the system under study, clearly show that the expected transient response of a hydro power DG-unit equipped with a synchronous generator strongly depends on both change in amplitude and phase angle of the terminal voltage caused by the fault in question, especially the active power response. An analysis taking only voltage change as the perturbation will in many cases most likely lead to erroneous conclusions regarding transient stability of the unit, critical clearing time, CCT, etc. Further work is necessary to quantify the effect of not taking into consideration the phase angle change in the FRT voltage profile curves found in various national grid codes.

A further work should include quantification of CCT for the different approaches (with/without taking into account phase angle changes) in view of loading (P and Q) of the synchronous machine, different synchronous machine parameter values, different types of excitation systems and tuning of these, whether a turbine/governor model have to be included or not, etc.

CONCLUSIONS

The results from this computer based simulation study shows that the transient response of a hydro power DG-unit equipped with a synchronous generator strongly depends both on change in amplitude and phase angle of the terminal voltage, resulting from a fault in the system. It seems reasonable to believe that an analysis taking only voltage changes into account most likely will lead to erroneous conclusions regarding FRT capability of the unit. Further work is necessary to quantify the effect of not including the phase angle change in the FRT capability assessment. A secondary goal of such a work should include the development of a simplified (computer based) method for assessing the FRT capability of DG-units, in view of expected responses in voltage (amplitude and phase angle) for realistic fault scenarios for medium-voltage networks.

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APPENDICES

APPENDIX 1. Line parameters

NAME	R [Ω/km]	X [Ω/km]	B [μS/km]	Length [km]
L1	0.001	0.001	0	1
L2	0.359	0.373	3.0756	25
L3	0.395	0.415	1.98	30
L4	0.098	0.398	2.8934	55.2
L5	0.098	0.398	2.8934	36.5

APPENDIX 2. Transformer parameters

NAME	S_n [MVA]	$U_{n,1}$ [kV]	$U_{n,2}$ [kV]	ER12 [pu]	EX12 [pu]
T1	5	0.69	22.0	0.005	0.100
T2	50	129.0	67.0	0.005	0.125
T3	20	62.0	23.0	0.005	0.100
T4	70	290.0	135.0	0.005	0.125

APPENDIX 3. Load data

NAME	P_{load} [MW]	Q_{load} [MVAr]
Load 1	20	7.5
Load 2	16	4

APPENDIX 4. DG model parameters

Parameter		DG model
X_d	[pu]	2.04
X_d'	[pu]	0.238
X_d''	[pu]	0.143
X_q	[pu]	1.16
X_q''	[pu]	0.137
r_a	[pu]	0.00219
X_l	[pu]	0.13
T_{d0}'	[s]	2.38
T_{d0}''	[s]	0.0117
T_{q0}''	[s]	0.11
H	[s]	1.0
V1D	[pu]	1.0
SE1D	[pu]	0.1
V2D	[pu]	1.2
SE2D	[pu]	0.3

APPENDIX 5. Voltage regulator data

Parameter			Description
K_P	[pu]	120.5	PID proportional gain
K_I	[pu]	165.5	PID integral gain
T_I	[s]	1	PID integral time constant
K_D	[pu]	25	PID derivative gain
T_D	[s]	0.01	PID derivative time constant
K_A	[pu]	1	Voltage regulator gain
T_A	[s]	0	Regulator time constant
V_{Rmax}	[pu]	35	Maximum regulator output
V_{Rmin}	[pu]	0	Minimum regulator output
K_E	[pu]	1	Exciter constant
T_E	[s]	0.5	Exciter time constant
S_{E1}	[pu]	1.346	Saturation curve value at point 1
E_1	[pu]	2.222	Voltage value at point 1
S_{E2}	[pu]	1.9	Saturation curve value at point 2
E_2	[pu]	2.962	Voltage value at point 2