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Capability of synchronous machines to ride through events with high ROCOF

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Abstract: The transition of power grids to implement large amounts of nonsynchronous renewables reduces the inertia in the power system. Therefore, the rate of change of frequency (ROCOF) after a fault of given energy is higher in low inertia grids than in grids with mainly synchronous machines operating. Standard faults for the design of existing synchronous machines assume fixed frequency grids, in which an electrically close fault happens. It is not tested, if the machines can ride through transient disturbances with high ROCOF. For ROCOF values of up to 1 Hz/s as foreseen for the upcoming grid code of the Republic of Ireland and up to 2 Hz/s for Northern Ireland, a thorough verification, if generators are capable to ride through such events is necessary. For this study, ROCOF frequency traces provided by the transmission system operators (TSOs) of Ireland were first benchmarked with a full-grid model and in a second step impressed on a model of generators connected to the power grid via a step-up transformer to study transient stability and nonlinear response of the generator. This paper focusses on the ability of nine different synchronous machines to stay connected to the transmission system during severe ROCOF events without losing synchronism.

Key words: ROCOF, under-excitation protection, turbo-generator, low-inertia grids

1. Introduction

The transmission system of the island of Ireland (All-Island Grid) is in a way a lab for the energy supply of the future. It has two high-voltage, direct current (HVDC) lines as only connection to other transmission systems. Stable wind conditions on and around the island of Ireland make wind farms a good choice for the built-up of renewables. Both will lead in the near future to new system behaviour with high rates of change of frequency (ROCOF) in case of grid faults, which may result in trips of generators or high loads on components. Most other countries will experience similar effects in the coming decades.

The Republic of Ireland and Northern Ireland as members of the European Union (EU) have to implement the aims of the EU Directive 2009/28/EC [1] within their local legislations. In this directive national overall targets for the share of energy from renewable sources in gross final consumption of energy in 2020 are settled. For Ireland, the target is 16%.

The governments of the Republic of Ireland and Northern Ireland have put up a 40% renewable electricity generation target for 2020, comprising 37% non-synchronous and 3% synchronous generation.

To achieve this aim, the Transmission System Operators of the All-Island Grid, EIRGRID and SONI, suggest a change of ROCOF values in the grid codes from 0.5 Hz/s to 1 Hz/s measured over 500 ms in the Republic of Ireland and 2 Hz/s measured over 500 ms in Northern Ireland in the case of a system separation. They provided frequency traces for ROCOF events, which they assume realistic for the new ROCOF values. The frequency traces contain no information regarding initiating fault-events.

It is not clear, if existing synchronous turbogenerators can safely operate under these new conditions. Existing studies concentrate on power system stability for low-inertia grids without looking at single machines [2]. Others focus on stability limits for the systems [3]. Further research is performed with regard to measures to mitigate the ROCOF after faults [4]. Finally, legislative aspects are of interest [5].

An insight into the effect of this new grid behaviour on synchronous machines, which are in large parts responsible for frequency stability, is urgently necessary.

2. Study methodology

2.1. Frequency traces provided for the studies

Fig. 1 shows the frequency traces provided by the TSOs for the studies. Fig. 1 shows the resulting ROCOF for a rolling measuring window of 500 ms. Traces 1 to 4 are applicable to all turbogenerators studied. The maximum ROCOF is 1 Hz/s for scenarios with a frequency rise and −1 Hz/s for scenarios with frequency drop. Traces 5 and are only applicable for power stations located in Northern Ireland. These represent events with ROCOF of −2 Hz/s and 1.5 Hz/s, respectively, which the TSOs deem realistic for severe ROCOF events in Northern Ireland.

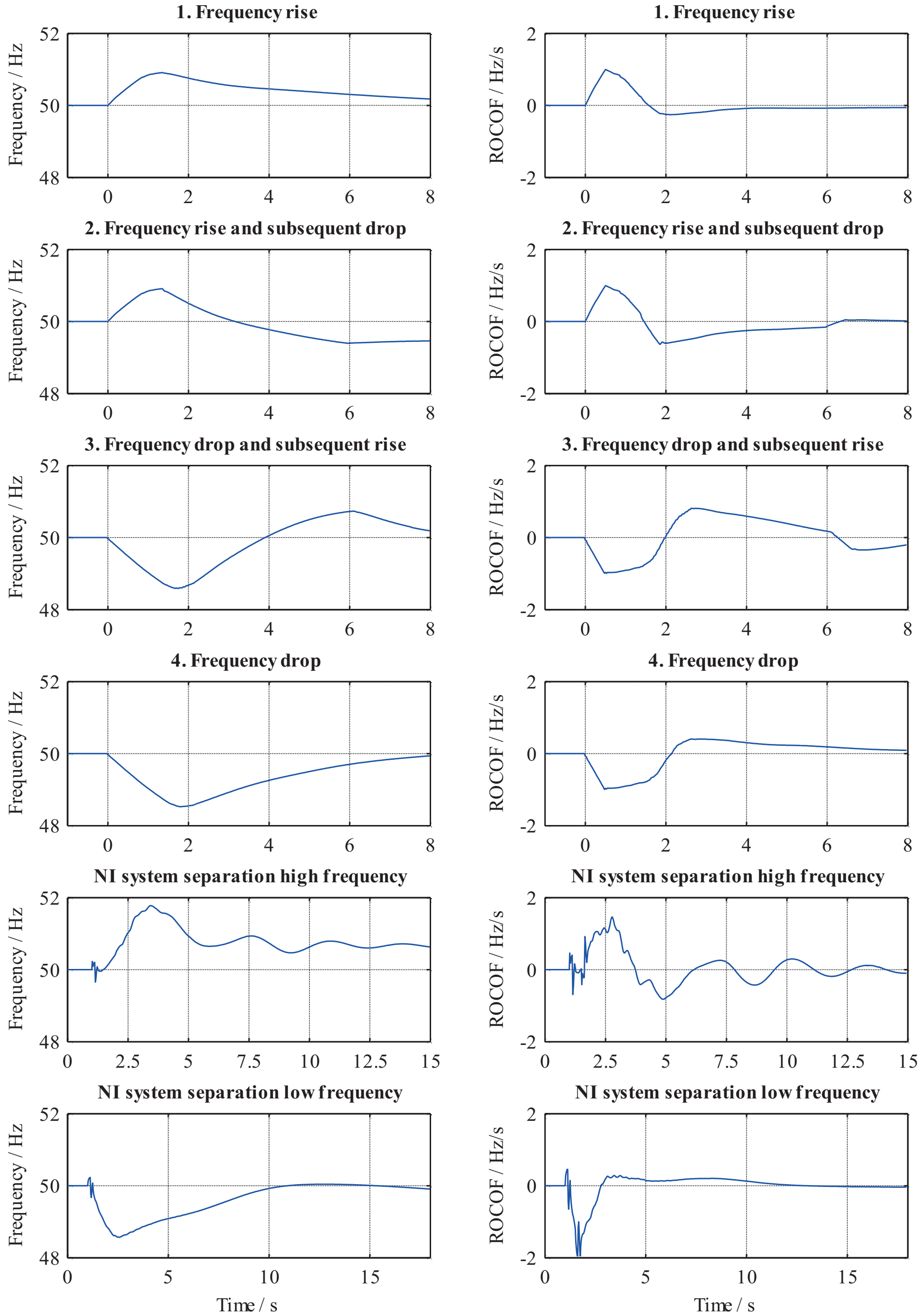

Fig. 1. ROCOF frequency traces

2.2. ROCOF after grid faults

Frequency stability is an important issue in power systems. ROCOF is usually defined as the change of frequency over time $\mathrm{d}f/\mathrm{d}t$ for instantaneous ROCOF or $\Delta f/\Delta t$, with a measurement over a given time window Δt. Within this publication the measuring window is $\Delta t = 500$ ms. The measuring window does not influence study results, because the frequency trace is applied to the generators under analysis and not the ROCOF value.

A trip of generation or load results in too much momentary load or generation in the system, respectively. To restore power balance, as a first reaction of the system, rotational energy of synchronous generators is converted to electrical energy to restore power balance in case of generation trips. In case of load trips, the opposite happens. In both cases energy of the failure is balanced by changing rotational energy of synchronous machines:

$$E_{\mathrm{fault}} \Rightarrow \Delta E_{\mathrm{rot}} = \frac{1}{2} J (\Delta\omega)^2, \tag{1}$$

where: ω is the angular velocity, J is the inertia, E_{rot} is the rotational energy and E_{fault} is the energy of fault.

Rotor speed of the synchronous machines consequently decreases for generation losses and increases for loss of load.

It has to be considered, that not the entire fault energy is converted to rotational energy of synchronous machines and that this equation does not contain the time dependent compensation process starting after the event, which depends on diverse parameters of the entire power system.

Now, we assume a fault resulting in an initial power change P_{fault}. Furthermore, we assume that the fault Energy E_{fault} is almost entirely transferred to rotational energy of synchronized machines:

$$\begin{gathered} P_{\mathrm{fault}} \Rightarrow \frac{\mathrm{d}}{\mathrm{d}t} E_{\mathrm{fault}} \approx \frac{\mathrm{d}}{\mathrm{d}t} E_{\mathrm{rot}} = \frac{\mathrm{d}}{\mathrm{d}t}\left(\frac{1}{2} J_{\mathrm{grid}} \omega_{\mathrm{grid}}^2\right) = \frac{1}{2} J_{\mathrm{grid}} \frac{\mathrm{d}\omega_{\mathrm{grid}}^2}{\mathrm{d}t} = \\ \frac{1}{2} J_{\mathrm{grid}} 2\omega_{\mathrm{grid}} \frac{\mathrm{d}\omega_{\mathrm{grid}}}{\mathrm{d}t} = J_{\mathrm{grid}} \omega_{\mathrm{grid}} \frac{\mathrm{d}\omega_{\mathrm{grid}}}{\mathrm{d}t} = 4\pi^2 J_{\mathrm{grid}} f_{\mathrm{grid}} \frac{\mathrm{d}\omega_{\mathrm{grid}}}{\mathrm{d}t}\,. \end{gathered} \tag{2}$$

Rearranging delivers

$$\frac{\mathrm{d}f_{\mathrm{grid}}}{\mathrm{d}t} \approx \frac{P_{\mathrm{fault}}}{4\pi^2 J_{\mathrm{grid}} f_{\mathrm{grid}}}\,. \tag{3}$$

This value is defined by the author as initial ROCOF value:

$$\mathrm{ROCOF}_{\mathrm{Initial}} \approx \frac{P_{\mathrm{fault}}}{4\pi^2 J_{\mathrm{grid}} f_{\mathrm{grid}}}\,. \tag{4}$$

After the fault, line frequency starts decreasing or increasing with approximately this ROCOF. Machines connected to the disturbed power system will react to the initial ROCOF and start rebalancing the system, which leads to oscillation of line frequency, pole angle, active and reactive power, and other parameters for a few seconds. Initial ROCOF depends on the inertia synchronized with the system. Low-inertia systems as studied here produce higher ROCOF for a given fault.

2.3. Grid models for the study

Simulating events with high ROCOF is possible with full grid models or substitute grids. A full grid model has the disadvantage that enormous amounts of information have to be implemented. To reduce efforts, substitute grids can be derived from relevant parts of the full grid model. Finally, an approach with impressed frequency is possible.

The models have to be suited for analysing transient stability of power systems. Therefore, an initial fault is assumed. The nonlinear dynamic response of the system to this large disturbance is then computed. The differential equations to be solved are nonlinear ordinary differential equations. The study has the form of a time-domain simulation. That means that the equations are solved step by step with numerical integration.

For this study, a model of the All-Island Transmission System has been set up that includes basic info on all major power plants. The distribution systems and loads were generalized and taken from publicly available data. With this model diverse severe transient disturbances ranging from machine trips to faults on HVDC lines have been simulated.

To study the effect of ROCOF frequency traces provided by the TSOs on the generator model, an infinite grid approach was taken and developed further for ROCOF studies. Usually voltage and frequency are assumed as being constant for the power system. For the transient studies presented here, frequency has to change according to the traces provided. Therefore, the power grid at the connection point is replaced by a single in-feeder. This single in-feeder needs to change its frequency according to the respective failure trace. In realistic grid models, reaction of the synchronous machine under analysis triggers reactions of other synchronous machines in the power system and thus influences the frequency behaviour. This effect needs to be neglected in favour of a general approach that delivers comparable results for diverse synchronous machines. An infinite grid is connected to two generators, the generator under analysis, Gen 1, and a generator Gen 2 that impresses the desired frequency trace on Gen 1. The substitute grid for this approach is shown in Fig. 2. Gen 2 is modelled with similar rated apparent power than Gen 1, but with a much smaller response time and a standard automated voltage regulator (AVR).

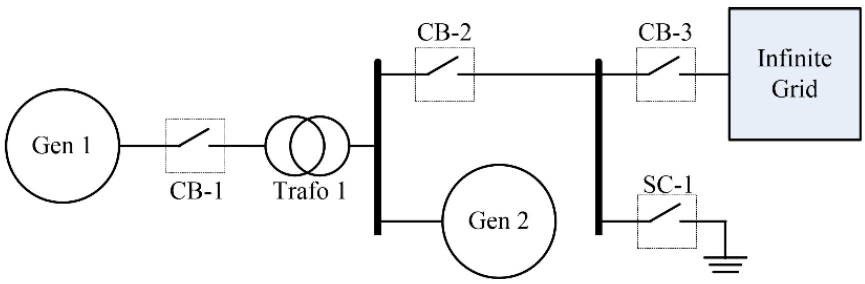

Fig. 2. Substitute grid for ROCOF traces

With this approach, the frequency traces provided have been reproduced quite exactly apart from a small initiating event at the beginning of the reproduced trace. Grid 2 was used for reference and the breaker CB-3 was open during simulation.

To benchmark severity of events with high ROCOF against standard faults, a substitute grid model for the generation of standard faults is generated as shown in Fig. 3.

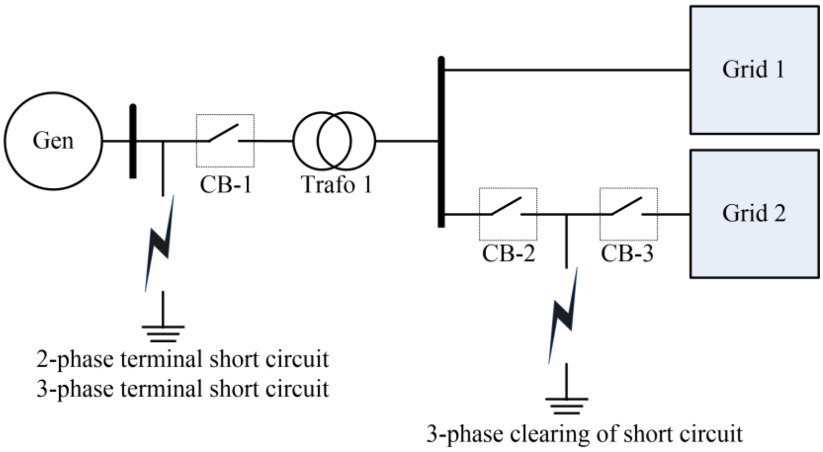

Fig. 3. Substitute grid for standard faults

Design cases analysed with this substitute grid are the following:
- 2-phase terminal short circuit,
- 3-phase terminal short circuit,
- 3-phase clearing of short circuit, clearing time between 80 ms and 400 ms in steps of 10 ms,
- fault synchronisation with angles 90°, 105°, 120° and 135°.

2.4. Electrical turbogenerator models

The synchronous machine is an electromagnetic system within the transmission system. The generator models are Park equivalents according to [6]. The Lagrange function of the synchronous machine delivers the corresponding equations of motion. From these, the inductances of the machine can be derived. The problem is that most inductances are angle dependent and thus the resulting nonlinear equations cannot be solved analytically. The widely applied so-called Park's transformation delivers a new basis, dq0, where angle dependencies of inductances disappear.

The main control-structures (automated voltage regulator (AVR), power system stabilizer (PSS), and turbine governing control (Governor)) are implemented.

The substitute generator Gen 2 is fitted to correctly model the short circuit behaviour at the grid connection node. The generator is connected to the grid via its generator transformer. Resulting electrical quantities are currents, voltages, pole slip, and electrical torques. For this study, currents and electrical torques are of particular interest.

The protection system of the turbo-generator or main transformer is not implemented in the model. Protection system reaction is evaluated either via data from test reports of protective devices provided by the owner of the plant of the synchronous machines or via COMTRADE files, which are directly applied to the machine.

2.5. Mechanical models

To evaluate effects on the integrity of the turbogenerator, mechanical models have been set up and evaluated:
- modal assessment of the turbine shaft,
- simulation of rotor end bells regarding slip and stresses,
- estimation of forces in the generator stator end windings,
- estimation of forces on the generator foundation,
- calculation of loads on turbine blades.

3. Findings

3.1. Basic generator data

Models of nine different turbo generators have been developed and investigated. For five of them first results are published in [7]. Table 1 lists basic data of the machines studied. As can be seen, rated power ranges from 30 MVA to 500 MVA, and types include Steam Turbines, Closed Cycle and Open Cycle Gas Turbines, as well as a Hydro Turbine.

Table 1. Basic data of investigated turbo generators

No.	Type	Generator rated apparent power	Rated power factor
1	ST	359 MVA	0.85
2	ST	318 MVA	0.85
3	ST	167 MVA	0.80
4	ST	182 MVA	0.85
5	ST	121 MVA	0.85
6	CCGT	500 MVA	0.85
7	CCGT	500 MVA	0.80
8	OCGT	73 MVA	0.80
9	Salient pole hydro turbine	30 MVA	0.75

3.2. Benchmark grid study

The benchmark of ROCOF values with a grid study revealed that for the current All-Island Grid the ROCOF proposed by the TSOs seem reasonable. For the transmission system, according to current planning for 2024, especially for low demand scenarios with high wind, some grid faults produce higher ROCOF, which could lead to cascade tripping and probably blackouts. Further investigations on this issue have to be done.

3.3. Oscillation of pole angle, active and reactive power

The rotor speed follows frequency trace 2 in Fig. 1 directly and looks for all machines very similar to the frequency trace presented there.

Pole angles move within the stable region; the synchronous machines do not slip in any scenario. Weakly damped oscillations of pole angle appear in several simulation cases showing the possibility of further generator-to-grid interactions that the studies presented here cannot reveal.

Fig. 4 below shows example results of pole angle oscillation for the case frequency rise and subsequent drop as shown in Fig. 1. The operating point is minimum active power output at maximum leading power factor. The turbo generators investigated are no. 1, 2, and 6.

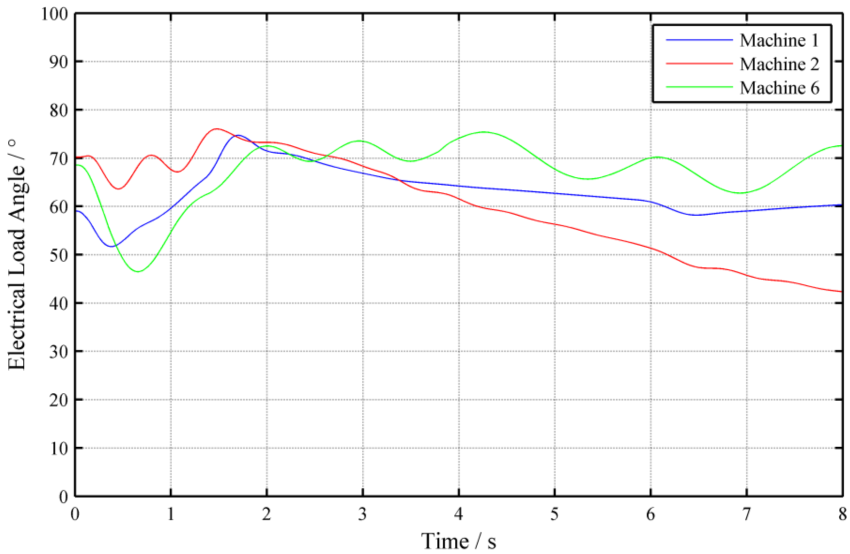

Fig. 4. Example case: electrical load angle

The steam turbine unit (No. 1) shows slight oscillations for approximately 2 s and moves to a different load angle. The steam turbine unit of the dual-shaft CCGT (No. 2) shows a slight oscillation and settles at a different load angle than in the beginning. The single-shaft CCGT (No. 6) oscillates quite persistently and does not subside until the end of simulation time.

If further electrical machines with weak coupling to the turbo generator No. 6 show oscillation of load angle with a similar frequency, these are coherent generators according to [8]. This means that they are susceptible of inter-area oscillations [9]. The oscillations observed for the impressed frequency approach within this study might worsen significantly and lead to further trips of generators.

The authors recommend further studies with substitute grids specifically designed to investigate ROCOF events with generator-to-grid interaction. Of particular interest should be investigations regarding coherent generators especially to those, which show persistent oscillations within the studies presented here. Reduced grids that serve this purpose can be derived for example from a full grid model with the technique presented in [10].

The mechanical study for machines 1 and 2 shows, that electromagnetic torques in the air gap resulting from the studies are not causing intolerable torques or fatigue of components. This study still needs to be done for the other machines.

The maximum spread of transient oscillations of active and reactive power outputs differs strongly between the different turbo-generators even of the same type.

Fig. 5 below shows example results for the oscillation of air gap torque for the same case and turbo generators as above.

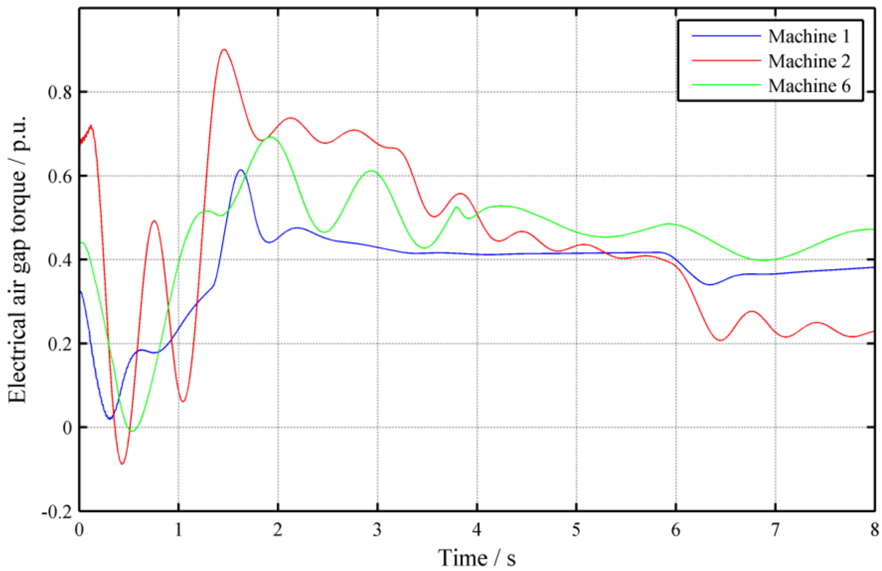

Fig. 5. Example case: electrical torque in the air gap

The electrical torque in the air gap shows only a perturbation in the first 2 s of simulation for the steam turbine unit (No. 1). The steam turbine unit of the dual-shaft CCGT (No. 2) oscillates with a starting amplitude of approximately 1 p.u. Oscillations are damped sufficiently and stabilize after approximately 8 s. The single-shaft CCGT (No. 6) oscillates with a starting amplitude of approximately 0.7 p.u. The oscillation is more persistent and shows only weak damping.

Reactive power oscillation is shown in Fig. 6 for machines 4 and 5 with a frequency trace prolonged linearly until 40 s simulation time. The test case is the frequency rise and subsequent drop scenario at minimum load and leading power factor as above. Line frequency is assumed to return linearly to 50 Hz until the end of simulation.

The capability limit of reactive power in the underexcited region (called underexcited reactive power limit in the following) of machines 4 and 5 lie in the region of −0.3 p.u. and −0.5 p.u. It can be seen, that machine 5 goes far out of underexcited reactive power limit, although the machine does not slip. In this case, the UEL should act and bring the machine back to normal operation.

Furthermore, the difference in reaction to the event after simulation time 8 s between machines 4 and 5 is striking. Further detailed investigations in the role of the control system and possibilities to change machine answers are highly recommended. This needs to include intense testing of changed control system settings to make sure, that the machine operates under all other conditions as desired, but reactive power is kept within underexcited reactive power limit for ROCOF events.

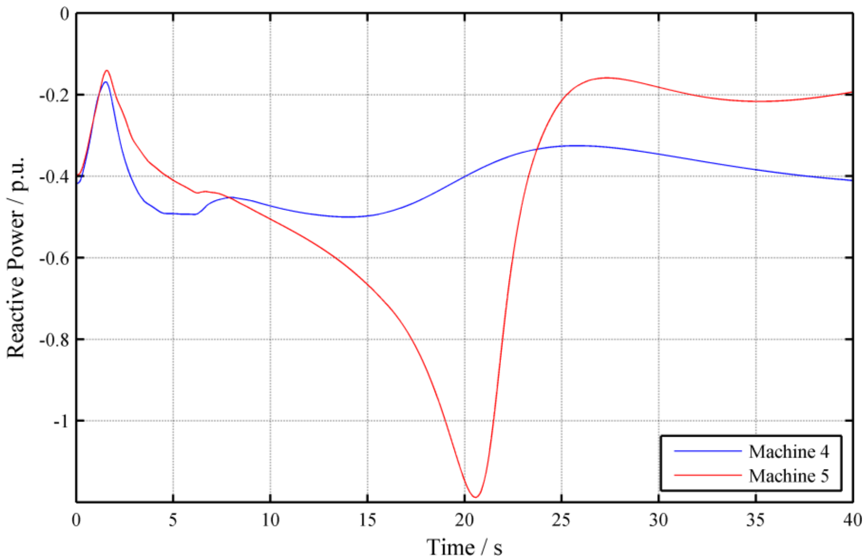

Fig. 6. Reactive power of machines 4 and 5 for frequency trace 2 at min load at leading power factor

Field current limit and underexcited reactive power limit are exceeded in several other cases, which are not shown here, by some machines. The machines return below these limits until the end of simulation.

Table 2 summarizes the resulting pole angle and power oscillation for each turbo-generator.

Table 2. Pole angle and power oscillation

No.	Pole angle and power oscillation	P_{pp} (p.u.)	Q_{pp} (p.u.)
1	Within underexcited reactive power limit. No pole slip.	0.7	0.4
2	Within underexcited reactive power limit. No pole slip.	0.5	0.2
3	Within underexcited reactive power limit, but slightly weakly damped in several cases. No pole slip.	1.4	0.2
4	Beyond underexcited reactive power limit for leading power factor cases. No pole slip.	1.4	1.0
5	Beyond underexcited reactive power limit for leading power factor cases. No pole slip.	1.2	1.1
6	Shortly outside underexcited reactive power limit for leading power factor cases, but weakly damped in some cases. No pole slip.	1.5	0.8
7	Shortly outside underexcited reactive power limit for leading power factor cases, but weakly damped in several cases. No pole slip.	1.6	0.8
8	Within underexcited reactive power limit. No pole slip.	0.9	0.8
9	Within underexcited reactive power limit. No pole slip.	0.9	0.9

For the maximum spread of transient oscillations of active and reactive power outputs only results from the four frequency traces applied to all synchronous machines have been considered. These are traces 1 to 4 in Fig. 1. Results from traces 5 and 6, which are only applied to the machines, that are located in Northern Ireland, have been omitted here for reasons of comparability. One outcome is that underexcited reactive power limit is violated for several leading power factor cases. This leads to actuation of the underexcitation limiter (UEL), if implemented, and can lead to trips by the underexcitation protection.

As different synchronous machines differ strongly with regard to diverse parameters like mass moment of inertia and rated power, the differences in peak to peak power do not have a single root.

3.4. Protection System Actuation

For seven of the investigated machines (No. 1–5, 8, and 9) test reports for the protection systems were available. The operator has tested the other two machines with the results in the form of COMTRADE files with a respective testing device. Due to missing data, the authors of this study could not verify the detected disconnection of both machines due to underexcitation protection.

The authors investigated at first, which of the protection functions each turbo generator has, and which can actuate with regard to the type of disturbances studied. These are:

- over-current protection,
- load unbalance protection,
- stator over-load protection,
- over-voltage protection,
- reverse power protection,
- over-excitation protection,
- under/over-frequency protection,
- underexcitation protection.

The authors compared study results with the set points derived from the mentioned test reports. Therefore, mathematical models of implemented functions have been set up and solved for the respective results. Table 3 shows the results for each generator.

As can be seen, the underexcitation protection actuates for 4 of the 9 synchronous machines investigated. For machines 4 and 5 the cases at min load and leading power factor for the traces frequency rise and subsequent drop, frequency drop and subsequent rise, and frequency drop lead to actuation of underexcitation protection. In addition, machine 5 gets disconnected for the same cases plus cases for the same frequency traces and leading power factor. Especially machines 4 and 5 exhibit striking behaviour with regard to violation of underexcited reactive power limit, going to reactive powers of $Q_{\min} < -1$ p.u., as shown in Fig. 6, whereas underexcited reactive power limit lies in the region of -0.3 p.u. and -0.5 p.u. depending on active power P and the respective machine.

Therefore, the respective machines would disconnect from the transmission system, worsening the failure scenario. Furthermore, excitation currents remain within normal boundaries and are not exceptionally low. To understand the reason for triggering of the underexcitation protection of several machines, the following paragraphs describe the purpose and function principle of underexcitation protection, before showing example results of the studies.

Table 3. Protection system actuation

No.	Trip	Freq. trace	Power factor	Case
1	No	–	–	–
2	No	–	–	–
3	No	–	–	–
4	Yes (under-excitation protection)	2, 3, 4	Leading	All
5	Yes (under-excitation protection)	2, 3, 4	Leading	All with min. power
6	Yes (under-excitation protection) according to operator	No data	No data	No data
7	Yes (Under-excitation protection) according to operator	No data	No data	No data
8	No	–	–	–
9	No	–	–	–

The underexcitation protection has the purpose of protecting the synchronous generator from consequences of loss of excitation by disconnecting the machine from the system. Possible consequences of loss of excitation are:
- instable behaviour and possibly loss of synchronism (pole slip),
- local overheating in rotor or stator,
- overvoltage in the rotor windings.

There are two principles of capturing underexcitation, one measuring the impedance Z and the other the admittance Y, the reciprocal of the impedance: $Y = Z^{-1}$. As most generators investigated, especially those where the underexcitation protection actuates, measure the impedance, the following paragraph describes this principle. To determine the impedance for this study, Ohm's law $\boldsymbol{V} = \boldsymbol{I} \cdot \boldsymbol{Z}$ with complex numbers of voltage $\boldsymbol{V}$, current $\boldsymbol{I}$, and impedance $\boldsymbol{Z}$ is used. At first the phase angle of voltage and current are determined to receive the complex values. It is important to know, which interlinked voltage and current is used for the measurement of the impedance within the underexcitation limiter. The operator provided clarified, which interlinkage is used.

The impedance is given as a complex number $\boldsymbol{Z} = R + jX$. Herein, R is the resistance and X is the reactance. Fig. 7 shows the protection settings in the typical form of limiting circles.

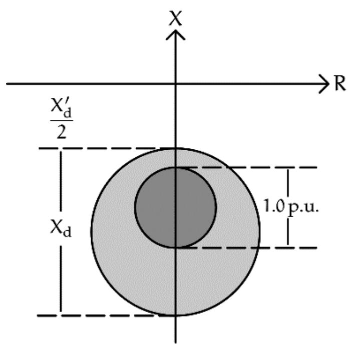

Fig. 7. Principle of underexcitation protection with impedance measurement

The Figure shows two circles, but there are also protection settings with only one limiting circle. During leading power factors (under-excited machine) the phasor of the monitored impedance moves in the fourth quadrant, thus the impedance region for triggering the protection is located in third and fourth quadrant. This explains why the cases with leading power factor cause the trips of machines 4 and 5. Each of the regions has a triggering time.

Fig. 8 shows the result for machine 5 and the same case as analysed above, where the impedance **Z** falls within the respective protection envelope for a longer time, triggering the protection function. Fig. 9 depicts the distance of the impedance **Z** from the protection circle over time for the same case. It is the minimum distance between the protection envelope and the phasor for a given time. When the impedance phasor enters the protection envelope, values get negative. As can be seen, the impedance **Z** remains within the protection envelope for 13 s. The triggering time is 0.5 s.

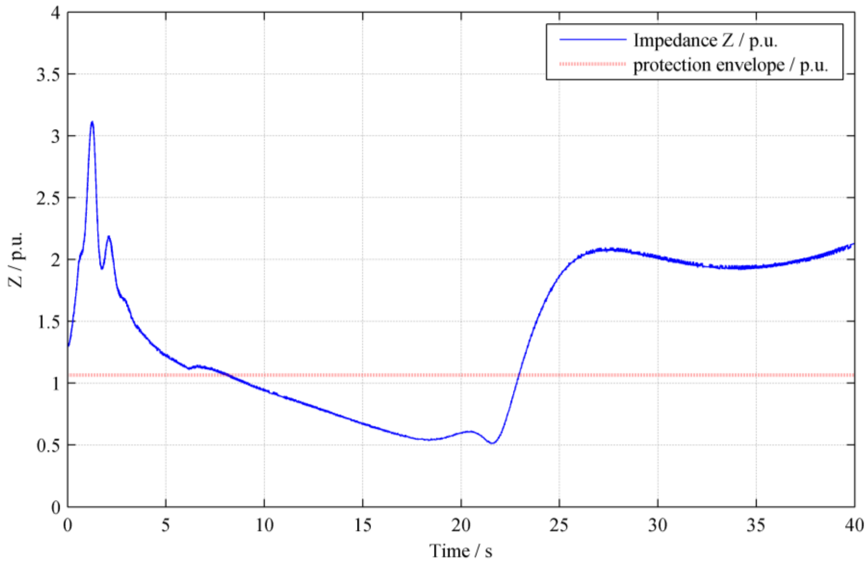

Fig. 8. Result example for underexcitation protection

This clear triggering of the underexcitation protection despite no pole slipping or loss of excitation indicates that changed settings might reduce trips of machines for some ROCOF cases. Further investigations into this topic are necessary to avoid repeated trips due to ROCOF events in the future, while still protecting the synchronous machines adequately.

The calculations have been repeated with the PSS switched off showing that no actuation of protections system needs to be feared in this case. Consequently, all cases for machines 4 and 5 have been repeated with switched off. No actuation of protection system is observed.

This shows that PSS tends to destabilize synchronous machines in ROCOF events. Changed settings need to be considered as well as a ROCOF detection that switches off the PSS or reduces output signal, when a ROCOF event is detected. ROCOF detection is possible using the rotor frequency, which follows grid frequency with short delay, or with the stator voltage, which changes

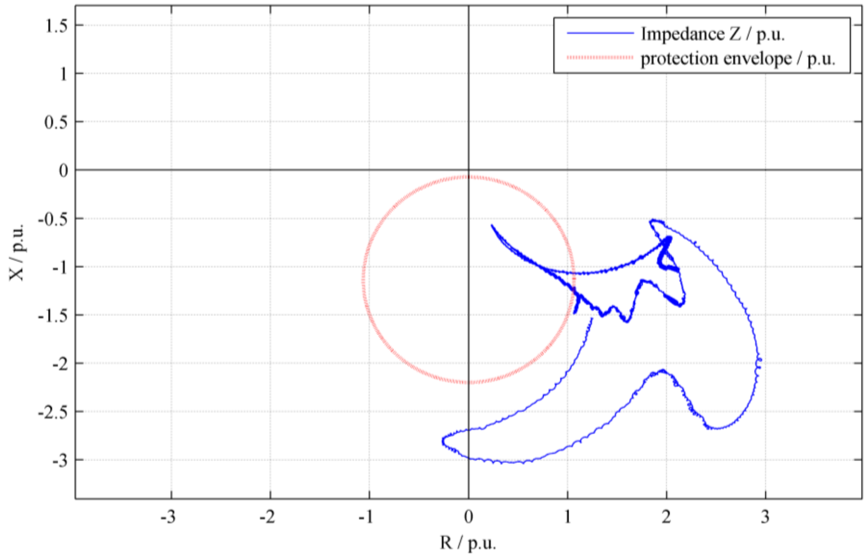

Fig. 9. Distance of impedance from protection envelope in p.u. vs. time in s

quickly in ROCOF events. Whichever functions can be implemented, a close cooperation of plant operators, system operators, and manufacturers is necessary and thorough testing of changed structures and set points.

4. Conclusions

The requirement for synchronous machines to ride through ROCOF events with up to 1 Hz/s or even more is currently being included in new grid codes [11]. Typically, such events are not considered during design of large synchronous machines [12].

This paper shows that events with high ROCOF rates that have to be expected in low inertia grids can cause persisting oscillations of pole angle, active and reactive power. Furthermore, machines might disconnect from the system due to counterproductive actuation of control and protection systems. Such trips worsen failure scenarios and could lead to brownouts or even blackouts. Further grid studies for faults initiating high ROCOF rates, which include subsequent cascade trips, are highly recommended.

Changed settings of a PSS might reduce trips of machines for some ROCOF cases without endangering the machine or power system stability. Further investigations into this topic are necessary to avoid repeated trips due to ROCOF events in the future. To ensure stability of low inertia power systems this is of crucial importance.

The impressed frequency approach taken for this study inhibits phenomena like interarea oscillation. It is of particular interest to develop suitable reduced grid models for ROCOF events that combine realistic behaviour with the possibility to analyse single synchronous machines in depth with reasonable efforts.

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