Frequency Regulation following the Network Code *Requirements for Generators* by ENTSO-E

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***Abstract*—The use of renewable generation has been increasing significantly in the last years, due not only to economic issues that demand a smaller dependency on fossil fuels, but also because of the growth of environmental awareness that appeals to a substantial decrease of harmful emissions to the atmosphere.**

Ideally, the high penetration of Renewable Energy Sources (RES) is possible, however, one must be aware of the frequency stability issues that come along with the increase of renewable generation, especially in small and autonomous power systems where bigger frequency deviations can be reached in shorter time.

To tackle this issue, the Europena Network of Transmission Systems Operators for Electricity (ENTSO-E) created a Network Code for all the generators connected to the grid defining the requirements regarding frequency regulation that they need to fulfil. With that being said, it is the aim of this study to evaluate how the implementation of these requirements influences the frequency regulation, improves the stability and allows a higher use of RES.

After modelling the electrical grid of Terceira Island (Azores) in the program Power System Simulator for Engineers (PSS/E), the dynamic models of governor's and wind turbines are studied. Furthermore a detailed insight in the Active Power Controller and Virtual Inertia Controller is given.

The results show that it is possible to maintain stability even with a larger share of RES provided that the requirements of the Network Code are met. Furthermore, a more conservative solution is found culminating in similar results to the ones obtained in the actual case.

I. Introduction

A. Motivation

The grid operational challenges are significant to increase securely the penetration of RES and these investments brought some technical issues to light, for instance: frequency stability.

To tackle the above mentioned issues the recent literature focuses on the use of Energy Storage Systems (ESSs), forgetting the high investment that it represents for the grid operators, whereas the ENTSO-E developed a Network Code applicable to all generators defining a common framework of grid technical requirements that the power generating units need to fulfil to solve the stability issues. This Network Code was approved by the European Union and is applicable from the year 2019 forward.

It is therefore of major interest to assess the impact of these requirements in a Portuguese electrical system and to evaluate the possibility of facilitating the frequency regulation by making the RES participate in the regulation, provided that the imposed requirements are fulfilled.

This would not only bring numerous technical advantages to the system, as the increase of the system's flexibility or the reduction of the conventional generator's efforts, but, allied to this, there are also great economical and environmental benefits, since a cutback in conventional generation is expected.

B. Outline

This paper consists of six chapters including this one, where the motivation for this study is exposed.

In the second chapter a literature review regarding the frequency regulation in hybrid systems is made, starting with the definition of basic concepts, followed by the methods used nowadays to enhance the contribution in the frequency regulation by the wind turbines and ends with a brief summary of the requirements imposed by the ENTSO-E.

The third chapter marks the beginning of the case study with the characterization of the power plants in Terceira Island (Azores).

The next chapter deals with the software used to obtain the results, PSS/E, describing the dynamic models used for the transient simulations.

The fifth chapter presents the most important results and analyses the difference in performance of the various systems taken in consideration.

Finally, in the sixth and last chapter the conclusions regarding the obtained results are drawn and suggestion for further investigation are suggested.

II. State of the Art

According to [1], *Power System Stability* is the "property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance".

After a disturbance the system itself fights tries to overcome the instability using its own inertia, the so-called inertial response. In a second stage, the installed control systems help finding a new steady-state level (primary control) and to return to the initial state (secondary control).

Being the inertia the first element to fight instability, the bigger the system's inertia constant, the smaller the initial rate of change of frequency (ROCOF), as showed in equation 1 taken from [2], being therefore easier to maintain stability.

$$\frac{d\omega_{el,pu}}{dt} = \frac{P_{gen,pu} - P_{load,pu}}{2H_{system}} \quad (1)$$

A. Control strategies for wind turbines

1) Speed control concepts: Nowadays there are four types of wind turbines regarding their speed control concept. In [3] an overview of the different types of wind turbines is made.

The first type, type A, is a fixed speed wind turbine. The main problem with this type of wind turbines lies in the fact that wind speed fluctuations are converted electrical power fluctuations, jeopardizing the system's stability in case of a weak grid.

The three remaining types are variable speed wind turbines and therefore they are able to match the wind speed with the rotor speed, benefiting from a higher efficiency. Type B and type C wind turbines only allow a limited range of speeds, whereas the type D wind turbines allow a full speed variation, being therefore the more interesting.

Although maximizing the efficiency is a big advantage, all the variable speed wind turbines are connecting to the grid through a power electronics converter, decoupling completely the turbine's rotating mass from the grid and preventing the turbine to sense frequency deviations and therefore to contribute with its own inertia to the inertial response.

2) Power control concepts: The power control is essential to restrict aerodynamic forces and to regulate the turbine's power output. Its main purpose is to at least prevent damages to the turbine when the wind is blowing at high speeds.

From the three existing power control concepts, *stall*, *active stall* and *pitch*, the latter one is the one used in the variable speed wind turbines. It consists in rotating the turbine's blades so that the aerodynamic forces on the blades are reduced, consequently leading to the necessary power reduction, as exlained in as explained in [3].

3) Active Power Control (APC): The previous section focused on the control concepts existing prior to the necessity of having wind turbines contributing actively to the frequency regulation. However, nowadays it is clear that the renewable power plants' contribution to the frequency regulation may be essential to a better grid operation, especially to the insular grids, as mentioned in [4].

The APC is part of the primary frequency control and its goal is to bring the grid's frequency to a new steady-state level. When a disturance causes overfrequency it is simple to solve the problem just by limiting the output power. However when an underfrequency situation occurs, the wind turbine should be able to inject more power to the grid. This is done by setting aside a reserve power, as explained in [5].

The most common method to fulfil this reserve requirement is explained in [5], using the example showed in figure 1. In traditional operating conditions (without reserve), a variable speed wind turbine is commanded to follow the red thick line, but with the reserve requirement, the path followed is the dashed green line.

This change of commands is made by the power converter control. The pitch control only plays a role for guaranteeing

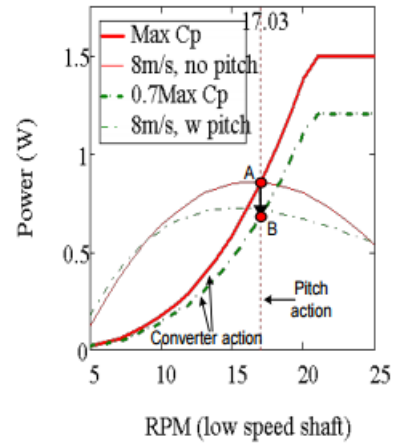

Figure 1. Operating points for the proposed power reserve control method, taken from [5]

that the aerodynamic operation of the wind turbine will be working at optimal efficiency, making the aerodynamic power move from the thin red line to the dashed green line after the pitch angle is adjusted. After the change in the power converter set point and in the pitch angle the operating point moves from A to B, maintaining maximum efficiency, bearing in mind that the reserve requirement is fulfilled.

After implementing the power reserve a Power - Frequency characteristic may be created as the one from figure 2. In underfrequency conditions, the wind turbine deploys the wind power reserve at the rate imposed by *droop* -, whereas in an overfrequency situation it can shed the output power according to*droop* +.

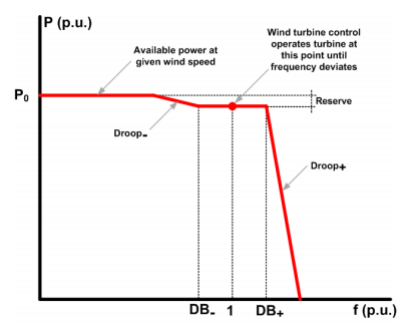

Figure 2. APC characteristic

It is important to mention that all the APC's parameters (deadbands, droop settings and reserve margin) do not have a predefined value, they should be tuned to obtain the optimum system's performance and to respect the corresponding grid codes.

The use of this control system is already well documented, for instance in [6], the impact on grid performance of frequency responsive controls such as APC is studied and the results are extremely positive. With a bigger wind turbines

penetration in the grid it is expected that the system's frequency declines more rapidly after the loss of a generator, which happens, but "*the net result is that the frequency nadir decreases with increasing wind power, and the longer-term primary response is somewhat better*". The author shows quantitative results and reports that for the studied case, using only APC, the minimum frequency is at the same level of the no-wind case (higher system's inertia).

4) Virtual Inertia: The inertia value of wind turbines is not insignificant, being actually big enough to have a positive influence in the system. As a matter of fact, in [7] two formulas are derived (equations 2 and 3) to estimate the inertia time constant (H in s) for generic wind blades. For instance, for a 900kW wind turbine with a diameter of 44m, such as the Enercon E-44, the equations lead to following results::

$$H \cong 2.63 \cdot D^{0.12} = 2.63 \cdot 44^{0.12} = 4.14s \quad (2)$$

$$H \cong 1.87 \cdot P_{rated}^{0.0597} = 1.87 \cdot 900000^{0.0597} = 4.23s \quad (3)$$

Even though only the blades are being considered a value of approximately 4s for the inertia constant is not negligible and using this inertia to smooth the frequency deviations would be extremely helpful for the frequency regulation.

The virtual inertia controller uses nothing else than the mechanical energy from the rotating blades and injects it in the grid as electrical power. According to [8] the idea behind this power injection lies on controlling the power electronic interface in order to behave as a conventional synchronous generator and have a considerable impact in the moments after a disturbance.

Studies have been made (as in [9] and in [10]) in order to understand which is the best way to create this synthetic inertia. Both authors agree that the inertial controller consists in adjusting the torque reference as a function of the ROCOF, releasing more kinetic energy stored in the rotating mass in the generator, particularly in the initial period of the disturbance. In other words, when the grid frequency falls, the electromagnetic power setpoint increases leading to a deceleration of the rotor speed and thus extracting the kinetic energy stored in rotating masses.

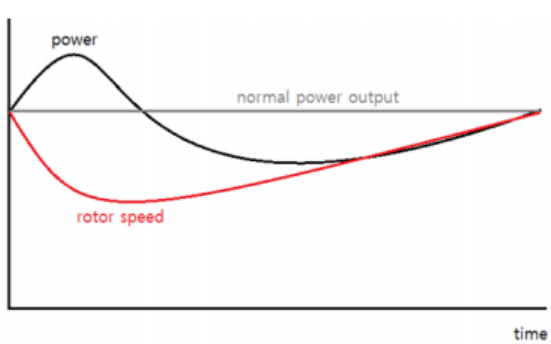

Figure 3. Typical electrical power output and rotor speed when using a virtual inertia controller

Big manufacturers, like Siemens (see [11]) or GE (see [6]) have been studying the impact of frequency responsive wind plant controls on grid performance and developing their own controllers.

Several authors have studied the effect of these virtual inertia controllers and reached some positive results, for instance, in [12] the Guadeloupe power system is studied and using the virtual inertia controller the minimum frequency is reduced by 250 mHz and the load-shedding observed without the controller can be avoided; in [6] in a system with 20% wind turbines penetration, the frequency nadir is 12% smaller than in the no-wind scenario and the improvement in the ROCOF is substantial. Last but not least, in the Nordic study, [13], several simulations with different levels of generation loss are made and the comparison between the system with/without virtual inertia controller is made, leading to the conclusion that "*it is possible to increase the minimum frequency and to prevent under-frequency load shedding. However, the contribution from the synthetic inertia might not be sufficient to prevent a large frequency drop in a severe loss of production*".

B. Scope of the ENTSO-E Network Code

The European Network of Transmission System Operators for Electricity (ENTSO-E) released in March 2013 the latest Network Code on *Requirements for Generators*. This document was prepared to give guidance to the national TSO regarding the grid connection of Power Generating Facilities. To do so, this document (see [14]) focuses on a selection of non-exhaustive requirements regarding several important topics in a power system, such as: frequency regulation, voltage stability, system restoration or robustness of the generating units with the aim of balancing European rules.

In the Network Code there is a wide variety of requirements regarding frequency regulation as for instance: frequency ranges, the rate of change of frequency withstand capability, communication and reconnection. However, the most important requirements for this study lie under the title *Limited Frequency Sensitive Mode - Overfrequency* and *Limited Frequency Sensitive Mode - Underfrequency*.

Both in case of underfrequency and overfrequency the Power Generating Module shall be capable of activating the provision of Active Power Frequency Response, with the difference that in the overfrequency situation the threshold lies between 50.2 Hz and 50.5 Hz and in case of underfrequency it lies between 49.5 Hz and 49.8 Hz. According to [14] the droop must lie between 2% and 12%.

In case of overfrequency, the Active Power Frequency Response should be able to work according figure 4, whereas in case of underfrequency the symmetrical should occur.

III. Grid's description

Nowadays there are three types of power plants in the island: hydroelectric, wind power and conventional (diesel). The three existing hydroelectric power plants have utilization factor of approximately 5% and none of the power plants has more than 1 MW of installed power. Therefore this type of power plants

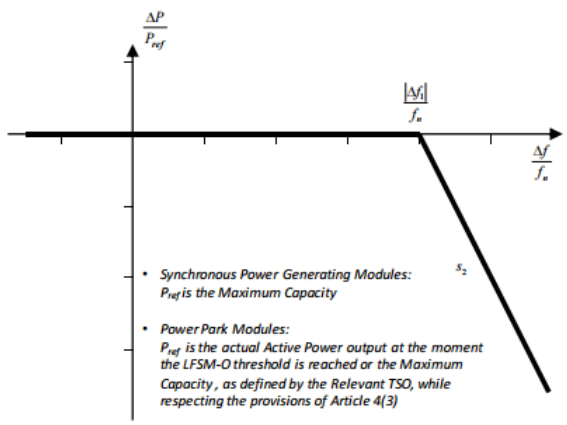

Figure 4. Active Power Frequency Response capability of Power Generating Modules in LFSM-O, taken from [14].

is not considered in this study and the focus remains in the conventional and wind power plants. A brief description of the other power plants is given in the following sections.

A. Conventional generation

The thermoelectric power plant of Belo Jardim aggregates the ten existing generators. Although all of them are driven by diesel engines, not all of them have them same specifications:

- G1 - G4: are the smallest generators included in this power plant and since they are not used in this case study, no further details are given.
- G5 - G8: these four generators have a nominal power of 7.625 MVA, operate at a voltage level of 6 kV and 500 rpm. The moment of inertia of these generators is 8.440 kgm^2.
- G9 - G10: these two generators are the biggest ones currently in operation in the island, both of them showing similar characteristics, 15.404 MVA of nominal power, working at a voltage level of 6 kV and at 500 rpm. The moment of inertia is also the biggest one so far with 12.738 kgm^2.

B. Renewable generation: Wind Parks

The total wind power installed in the island adds up to 12.6 MW, 9 MW in the first park and 3.6 MW in the second. In both parks the same model of wind turbines is installed, namely, the Enercon E-44. This model has a rotor diameter of 44m and a rated power of 900 kW.

The turbines fit under the type D category (see section II-A1) and therefore are able to work at a variable speed, reaching their rated power at a wind speed of 17 m/s. Although it is considered that these wind turbines are equipped with a virtual inertia controller and an active power controller, originally these turbines do not possess any kind of controller, only allowing to be remotely turned off by the grid operator.

It is also worth mentioning that the utilization factor of these wind parks in the year of 2014 was over 35% indicating how favourable the conditions in the island are for wind turbines.

IV. PSS/E: Dynamic models used

A. Conventional Generation Related Models

Regarding the conventional generators used in the grid, some simplifying assumptions were made, namely: all generators are salient pole generators and all generators have the same excitation system

With that being said the models *GENSAL* and *IEEET1* are used to represent this components. Since these models are widely spread and typically used in studies of this nature, no more details will be given with respect to these models.

On the other hand the models used to represent the diesel governors in each generator, *DEGOV* and *DEGOV1*, have a fundamental role in the frequency regulation. The *DEGOV* is a model of an isochronous governor, whereas the *DEGOV1* is a model of a governor for a diesel engine where the droop control is either throttle or electric power feedback.

In an isolated system usually droop must be used to share the loads, but the isochronous mode can also be used on one engine, running in parallel with any other engine, bearing in mind that this second engine may not be operated in isochronous mode as well. If this happens one of the engines will try to carry all the load while the other will shed all of its load. The result will be that the first engine will continue to take all of the load until it reaches its power limit, and the other engine will shed all of its load and become motored (driven by the other engine).

Although operating in the isochronous needs more attention by the grid operator it was chosen for this study to operate in the isochronous mode: all engines in the system are operated in the droop mode except for one which is operated in the isochronous mode.

The output power of the isochronous unit will change to follow variations in the load demand while maintaining constant speed/frequency of the system provided that a load change does not result in:

- a power output bigger than the combined output of the isochronous unit and the droop machines
- a power output below than the combined output of the droop machines

In order to allow a bigger increase/ decrease in the load, the machine with the highest output capacity was chosen to operate in the isochronous mode. This choice was made considering the same efficiency for all the machines in the grid and expecting big power unbalances, such as the loss of a generator. The droop machines will run at the frequency of the isochronous unit.

B. Wind Turbines Related Models

Although type D wind turbines are present in PSS/E's standard library of dynamic models, [15], the adopted model for simulation purposes is developed by GE.

As showed in 5, the GE models are composed by three device models:

- Generator/Converter model
- Electrical control model

- Turbine and turbine control model

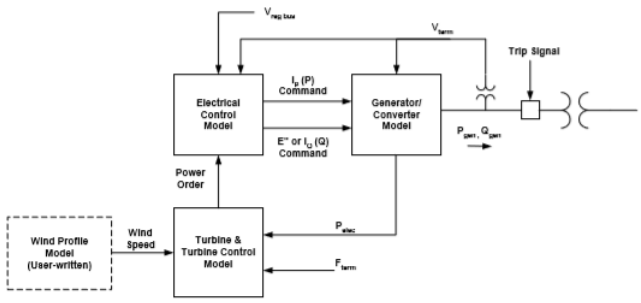

Figure 5. GE Full Converter Wind Turbine Generator Dynamic Model Connectivity, adapted from [16]

Besides these three main models there is the possibility of introducing other types of control, such as the textitWindINERTIA and the *Active Power Control*.

In short, the *WindINERTIA* is able to simulate an inertial response similar to the ones from conventional generation and the APC is responsible for controlling the active power generated according to the frequency value at each instant.

1) WindINERTIA: The block diagram of this controller is exposed in figure 6.

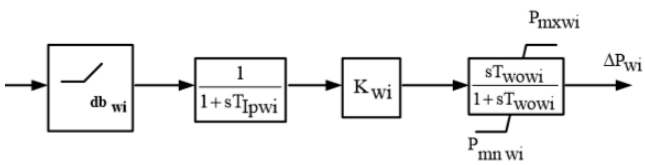

Figure 6. GE's *WindINERTIA* controller, adapted from [16]

It is important to note that the control is not symmetrical, only responding to low frequency events, because only in that it is needed to increase the power output. Responsible for limiting the working range of this controller is the deadband, db_{wi} shown in figure 6. The gain K_{wi} influences directly how fast the controller injects the maximum extra power allowed, which is normally around 10%. The two time constants determine how fast the turbines react and how fast they recover from the loss of mechanical power.

Naturally the optimal value for these parameters is hard to find, because it normally implies a trade-off between two situations, for instance in [13] it is stated that the gain's tuning is a trade-off between the contribution in the initial seconds after the disturbance and the need for additional power resulting in a delayed frequency recovery.

Moreover, one must keep in mind that some parameters are limited by some physical factors, as it happens with the maximal extra power delivered, that strongly depends on the available wind and more importantly of the aero-mechanical ratings and speed limits.

2) APC: Although in [16] it seems that every aspect of this controller is theoretically correct, after some simulations using PSS/E-32 it was observed that the system only works properly when the frequency deviation is positive, resulting in a decrease of the injected power. When an underfrequency event is registered, the program isn't able to provide a power increase based on the power reserve.

To rectify this problem, a fictitious load is connected to the grid in every bus with a wind turbine. If the APC is active, each of these loads will initially have the value of the power reserve predefined for each turbine and will change its value during the simulation according to the predefined APC characteristic and to the measured frequency.

This characteristic is obtained by following the instructions of the Network Code. Furthermore one must keep in mind that the wind turbine's power output will remain constant throughout the whole simulations and the load's value is the only variable in the APC system, registering its minimum in case of severe underfrequency (allowing the turbine to inject all available power to the system) and a maximum in case of overfrequency (shedding all the turbine's production).

V. Simulations & Results

A. Chosen Scenario

Being the aim of this study to analyse the impact of the ENTSO-E RfG standard in the normal operation of the electricity grid and having in mind that the requirements imposed by the standard will affect mostly the renewable power plants, the bigger the relation between renewable power produced and total power generated, the more interesting is the scenario. It is also important to evaluate if in the measured data the production is limited to avoid instability situations.

With that being said, the chosen option was the scenario of September 2014 at 05:30. During the early hours of the night in question (between 2:30 and 07:00) it is clear that the wind power was limited to 4 MW (see figure 7).

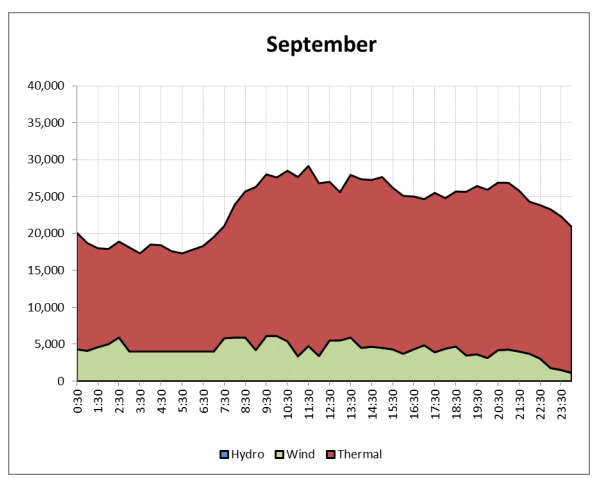

Figure 7. Power produced in a typical day of September 2014

Before analysing the performance of the controllers responsible for the frequency regulation it is important to clarify the different cases that were considered for the execution of

the simulations. There are five different cases: one of them represents the real distribution of power generation depicted in figure 7, whereas the four others are fictitious cases developed to study the impact of the several controllers.

1) Real situation:
   - 4 MW of wind power.
   - 13.3 MW of conventional generation divided by the two biggest generators, G9 and G10, both working at approximately half of their rated power.
2) Full renewable with no frequency regulation:
   - 12.6 MW of wind power. Imagining that the wind speed allows all the 14 wind turbines to work at their rated power (0.9 MW).
   - 4.7 MW of conventional generation divided by two medium-sized generators, G7 and G8, both working approximately at 40% of their rated power.
3) Full renewable with enabled APC:
   - 11.3 MW of wind power. Imagining that the wind speed allows all the 14 wind turbines to work at their rated power (0.9 MW), but since the APC is enabled, a power reserve (in this case 10%, or 0.09 MW) is left aside for frequency regulation.
   - 6 MW of conventional generation divided by two medium-sized generators, G7 and G8, both working approximately at half of their rated power.
4) Full renewable with enabled Virtual Inertia:
   - 11.7 MW of wind power. To maintain a load value of 17.3 MW and to be able to keep the two medium-sized generators working at a decent load level, only 13 wind turbines are in service and working at full power.
   - 5.6 MW of conventional generation divided by two medium-sized generators, G7 and G8, both working approximately at 46% of their rated power.
5) Full renewable with enabled APC and Virtual Inertia:
   - 11.3 MW of wind power. The APC is enabled and therefore a power reserve is needed.
   - 6 MW of conventional generation, divided equally by G7 and G8.

B. Analysis of the APC parameters

1) Deadband: A series of disturbances were caused to the grid to evaluate how resistant the grid is to power imbalances. According to table I an imbalance of approximately 1 MW is needed to cause a frequency deviation inside that lies inside the predefined threshold for the deadband.

A disturbance that severe does not usually occur and it is most likely the result of the connection or disconnection of a machine to the grid, such as a motor from an industrial facility or the tripping of one of the generators in service.

Consequently, and in order to maximize the use of the APC one must set the deadband's value to its lowest value allowed by the Network Code, $\pm$ 0.004 pu.

In the underfrequency situation, when adding load to the system, the resulting maximal frequency deviation is similar to the one obtained and therefore the chosen deadband's value is the same.

Table I
DEADBAND'S DETERMINATION - OVERFREQUENCY

#	$\Delta P(MW)$	$\Delta Q(MVAr)$	Max. Freq. Deviation (pu)
1	-0.44	-0.18	+0.0017
2	-1.04	-0.45	+0.0042
3	-1.44	-0.22	+0.0057
4	-1.72	-0.34	+0.0069
5	-2.03	-0.51	+0.0084
6	-2.48	-0.67	+0.0100

2) Droop: The disturbance used to evaluate the influence of the droop is causing a maximal frequency deviation twice as big as the deadband of approximately 0.0080 pu. To evaluate the influence of the droop in the obtained frequency deviation, the simulations were performed for three different droop values (2%, 7% and 12%) and with no APC.

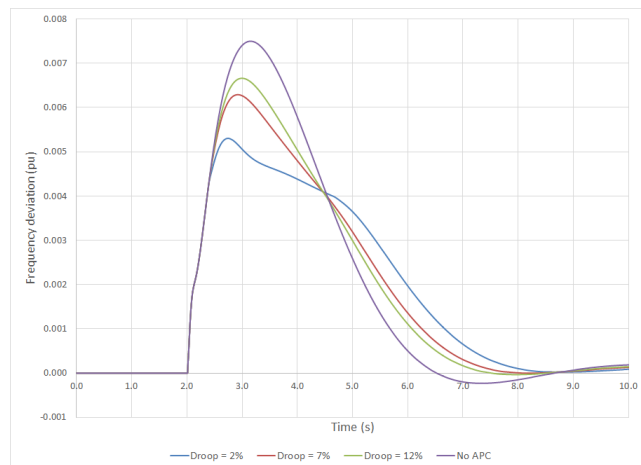

Figure 8. Effect of the droop value

Looking at figure 8 one must agree that the results are in accordance with the theory since the peak of frequency deviation is decreasing, as the droop value decreases, because the low droop value originates a steeper P-f characteristic, which leads to a bigger contribution by the wind turbines for the frequency regulation.

One should also mention that there exists a trade-off between the droop value and the frequency recovery time: the lower the droop, the higher the recovery time. With no APC enabled the frequency returns to its nominal value after approximately 6.5s whereas with a 2% droop it takes 8.5s to reach its nominal value again. Even though this argument is against the use of lower droops, its importance seems reduced after observing the improvement of the maximal frequency deviation.

All in all, after analysing the results presented in this section, one must conclude that a smaller droop value brings more benefits than disadvantages to the system and therefore it is suggested the use of low droop values, around 2%.

3) Delay: The results presented so far are based on an ideal controller, but since this model is supposed to represent a real controller it must have delay time.

This delay time is composed by several parts: time for sensing the actual frequency (at least 0.06s), time to calculate the needed active power for the reserve according to the measured frequency and the corresponding thyristor's angle able to lead to this value (nowadays, with all the computing resources this time is negligible) and finally act on the power electronics itself to achieve the wanted angle (at least 0.02s). This adds up to a total delay time of at least 0.08s.

In the ENTSO-E Network Code there is few information regarding exactly how fast the controller must be able to react, saying only that the "*speed of Active power activation can be different depending on technology, but it is important that time of activation is as short as possible, otherwise this requirement cannot contribute to system stability*".

As expected, the results show that a bigger delay leads to a bigger deviation, indicating that the controller installed must react as fast as possible.

C. Analysis of the VI parameters

Usually, the main goal of using this controller is to synthetically increase the system's inertia in case of underfrequency in order to decrease the rate of change of frequency. Therefore it would be interesting to adapt the controller in order to have a significant impact immediately after the disturbance is detected.

1) Deadband: The smaller the deadband, the more sensitive the controller will be. However, it is not advisable to set a low value for the deadband, because the grid during its normal operation may have some frequency oscillations and in those cases there is no need for the controller to react. On the other hand a too big deadband may cause a reaction by the controller when its contribution is already ineffective to the frequency regulation.

After some simulations it is observable that the standard deadband of 0.125 Hz (recommended by GE) is a satisfactory value, because simulations were performed using a value of 0.025 Hz and the frequency deviations are similar. This indicates that such an earlier activation of the controller does not lead to a significantly faster and more efficient reaction.

2) Filter time constant: To be able to add inertia to the system in the moments right after the disturbance, the controller must act fast. To do so, the simulations were made with different values for the filter time constant. The results are presented in figure 9.

As one may observe the smaller the time constant the better the result in terms of reaction time. One can clearly recognize a smaller rate of change of frequency as the filter time constant decreases.

3) Gain: To have a significant impact on the frequency in the moments right after the disturbance is as important as having a fast reaction and therefore the gain must be set to a highest value possible.

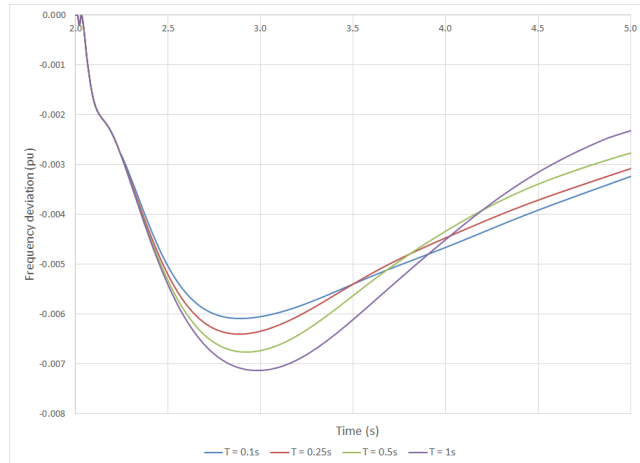

Figure 9. Virtual Inertia parameters' effect on the frequency response (+1.83 MW disturbance): Filter time constant

As one may observe in figure 10, the higher the gain, the more extra power is given by the turbine to the system. Since normally not more than 10% is given, the suggested gain value should be approximately 20.

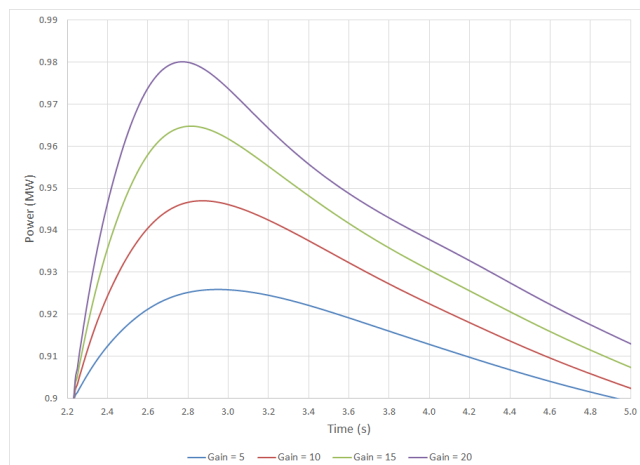

Figure 10. Virtual Inertia parameters' effect on the power injected to the grid (+1.83 MW disturbance): Gain

4) Washout time constant: The washout time constant is responsible for how fast the frequency recovery occurs. However, the faster it occurs, the bigger the frequency nadir and the bigger the overshoot at the beginning of the stabilization phase. These two aspects are evident in figure 11.

These aspects are more evident in the curve with the shortest washout time constant (blue curve). The best compromise between recovery time and performance would be a value around the 2.5s (resulting in a curve similar to the red one).

D. Comparison between cases

1) Overfrequency - load loss of 1.88MW: In figure 12 one can observe that the actual case has the best performance,

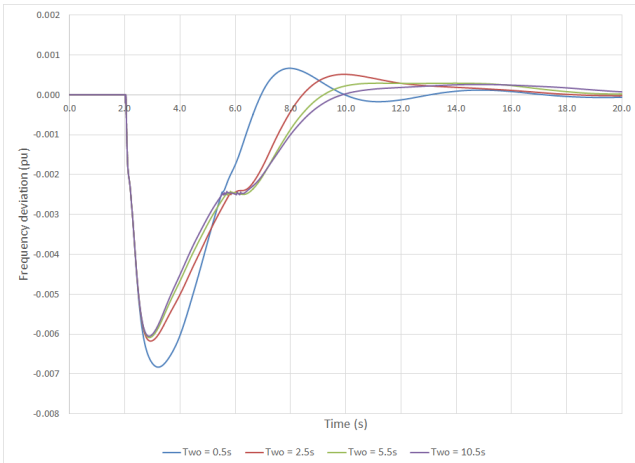

Figure 11. Virtual Inertia parameters' effect on the power injected to the grid (+1.83 MW disturbance): Washout time constant

showing a smaller deviation and a faster recovery. This occurs because the two biggest generators are in service and their inertia eases the disturbance's effect. In the case where no control is active (red curve) the maximal frequency deviation is twice as the one registered in the actual case.

With the most strict parameters allowed by the Network Code (2% droop and a deadband of 0.004 pu) the APC leads to a smaller maximal deviation, but it isn't able to reduce the ROCOF in the initial moments after the disturbance. Nonetheless, the improvement shows the benefits of the use of the APC in a system like this one.

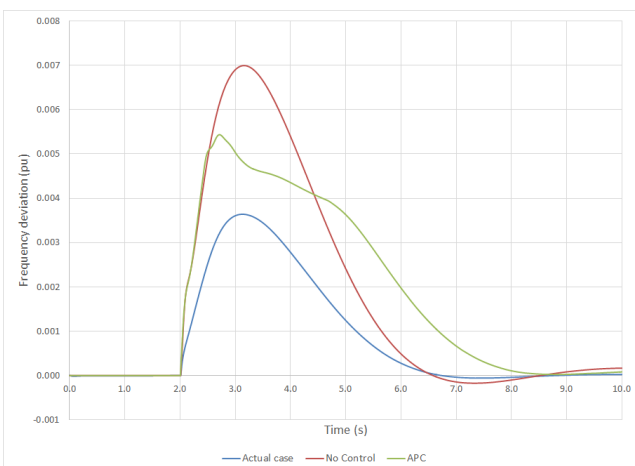

Figure 12. Comparison between control strategies: Overfrequency

2) Underfrequency: load increase of 1.83MW: Again the actual case (blue curve) shows the best response to the disturbance, reaching a deviation of -0.004 pu, whereas the case with no control (red curve) reaches a value approximately twice as high. Both these cases, where no additional controller other than the generator's governor is active, have the smoothest and fastest frequency deviation recovery.

Also included in figure 13 are three other curves, one representing the case where only APC is active (case 3), the other one representing the case where only the Virtual Inertia controller is active (case 4) and the last one a curve where the efforts of both controllers are combined (case 5).

The green curve (only APC is enabled, case 3) follows the red curve (no control) until the APC's deadband is reached and the delay time required for the APC's reaction is surpassed. Afterwards the influence of the continuously changing power reserve of the APC is felt and the frequency deviation is rapidly limited to a value around -0.0055 pu. One may observe that this curve does not recover as fast as the blue one (actual case) or the red one (no control case), but still its stabilization time is quite satisfactory.

The purple curve, representing the case where only the virtual inertia controller is active (case 4) is completely different when compared to the others, presenting a more flattened behaviour and reaching its lowest point only after almost 4s. One can see that this curve starts to diverge from the others (green and red curves) in the instants right after the disturbance achieving a better ROCOF, being this its main advantage.

The case where both controllers are active (case 5) is represented with the light blue line and since the two controllers are active, a combination of their advantages and disadvantages is to be seen. Starting with the disadvantages, one can observe that the recovery time is the worst one presented in figure 13. Furthermore the successive activation and deactivation of the virtual inertia controller leads to an extended intermission in the frequency recovery process around the controller's deadband.

On the other hand there are also positive aspects resulting in the combination of the two controllers, namely: the improvement in the ROCOF and the value of the frequency nadir. The ROCOF obtained is even better than the one obtained in the fourth case and the frequency's deviation nadir is achieved in the initial moments after the disturbance and its value lies around the -0.005 pu, being only approximately 0.001 pu, or 0.05 Hz, smaller than the one obtained in the actual case.

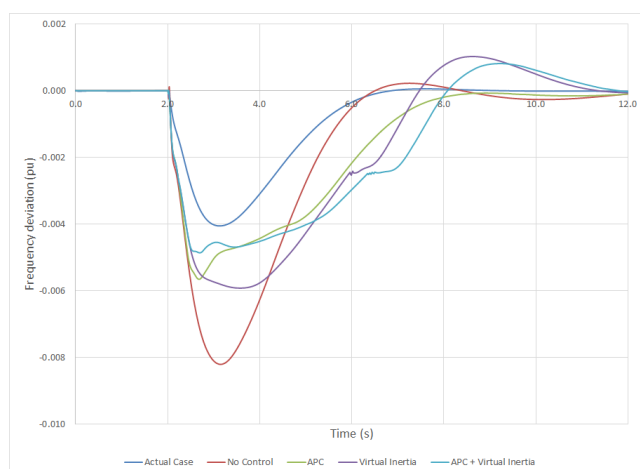

Figure 13. Comparison between control strategies: Underfrequency

3) Underfrequency: tripping a generator: This time the actual case (case 1) presents the worst results (blue curve) reaching a value of -0.02 pu, even worse than the case without controllers (-0.015 pu). This happens because in the real situation the fact of tripping a generator implies a power imbalance of approximately 6 MW, whereas in all other cases the power imbalance is approximately half of it. Along with this aspect, the ROCOF of the actual case is also the worst from all the presented cases.

The green curve, representing the case where only APC is active (case 3) presents very interesting results, showing a major improvements when comparing to case 2 (red curve) with the frequency nadir improving approximately 0.003 pu. The longer frequency recovery is also present and this time even more prolonged.

The fourth case, with only the virtual inertia controller and represented by the purple curve, shows a slight improvement in the frequency nadir and in the ROCOF, but not as meaningful as the one seen in the last disturbance. The enormous power imbalance makes the effect of injected power by the virtual inertia controller seem unimportant, indicating that this controller is not the best for such big disturbances.

Finally, the fifth case (light blue curve), where the APC and the virtual inertia controller are active presents the best result. In terms of ROCOF one sees that, with help of the APC the virtual inertia controller is already able to contribute substantially to the inertial response of the system, resulting in a smaller slope right after the disturbance. The frequency nadir registers, the best result, by far, in comparison with all the other curves, being approximately half of the one obtained for the case with no control (case 2) and a third of the one obtained in the actual case.

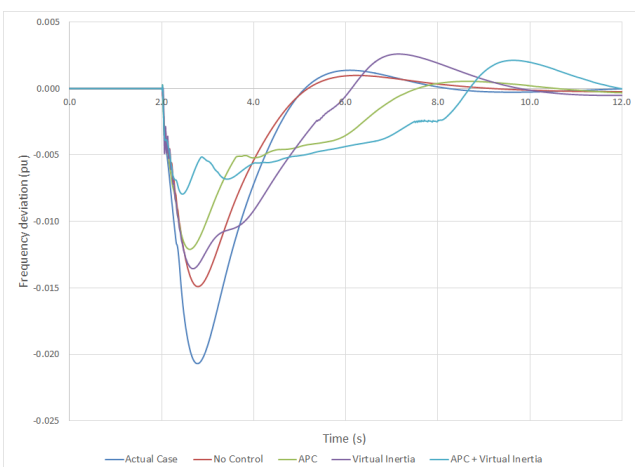

Figure 14. Comparison between control strategies: Underfrequency, tripping a conventional generator

To conclude, it is important to emphasize that every case is able to deal with such a strong disturbance and to regain frequency stability, proving that the use of these two controllers is reliable and may bring some benefits to the system even after the strongest disturbances.

E. Alternative case

In the following another possibility is analysed, namely a more conservative one, where instead of reducing the conventional power from 13.3 MW to 6.1 MW, the reduction is made from the 13.3 MW in the actual case to 9.2 MW. This implies that another conventional power generating unit is in service, contributing to the system's inertia and thus facilitating the frequency regulation.

In the actual case, two generators of 12.3 MW are being used and they are working at 54% of their rated power, whereas in this new case, there would be three smaller generators, each one with a rated power of 6.1 MW working at half load.

The efficiency of diesel generators is known to be almost constant for load values between 50% and 100% as stated in [17]. Although the efficiency is similar, the fuel consumption might change because of generator's size. Using the results from [18] the fuel consumption grows linearly with the size of the generator, implying that a 30% reduction in the conventional power used leads to approximately a 30% reduction in the fuel consumption. Therefore it is safe to say that this configuration is still very beneficial for the grid operator, both economically and environmentally.

From a technical point of view this network configuration only surpasses the actual configuration in case of big disturbances (power imbalances around 1.8 MW).

However, one must keep in mind that this disturbance (+1.8 MW) only originated a deviation of approximately 0.005 pu (see figure 15), which means, that smaller disturbances are not worrisome to the frequency regulation, although the actual case still achieves a better performance.

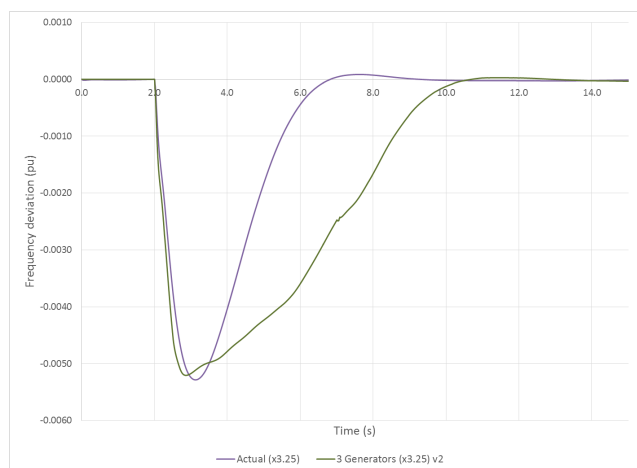

Figure 15. Frequency deviation after +1.8 MW disturbance

As one may observe in figure 15 the alternative case shows a ROCOF not very different to the one obtained in the real case and, furthermore, the frequency nadir measured is smaller than the one obtained in the real case. On the other hand, the frequency recovery time is approximately 4 seconds longer,

but this is the small price to pay for a similar frequency nadir and ROCOF and for a 30% saving in fuel.

VI. Conclusion

All in all, after analysing the results it is fair to say that the controllers have an important and positive impact in the system.

For a grid with a generation of approximately two thirds of two thirds of renewable and one third conventional, resulting in a small system's inertia, the controllers allow a huge improvement in the frequency nadir and in the ROCOF.

From the results one observes that all parameters of the both controller have a main impact in the frequency response. The APC is mainly responsible for the improvement of the frequency nadir, depending strongly on a short deadband and on a low droop, being the lowest values allowed by the Network Code the more appropriate in this case (0.004pu for the deadband and 2% for the droop).

The Virtual Inertia Controller is based on four main parameters: the deadband, the filter time constant, the gain and the washout time constant and their optimal tuning is one of this controller's main challenges. The results show that for obtaining a strong, immediate response to an underfrequency disturbance to improve the ROCOF, one must choose a high gain value and small time constants, bearing in mind that these strongly influence the frequency recovery time.

When comparing to the actual case the best performance occurs in an underfrequency situation when both controllers are active. Even though, neither the frequency nadir nor the ROCOF are as good as in the actual case, a big improvement is noticeable. Moreover, every case is able to maintain stability even after a strong disturbances such as tripping a generator.

After proving that both controllers have a positive impact on frequency regulation an alternative and more conservative case is created, where the conventional generation only decreases from 13.3 MW (actual case) to 9.2 MW. This decrease in conventional generation implies a fuel saving of approximately 30% and, according to the simulations presented, for big disturbances, as a load increase of +1.8 MW, the controllers allow a similar response as the actual case, with an identical ROCOF and a slightly better frequency nadir.

To conclude one must recognize that this Network Code has a very positive effect in the frequency regulation indicating why this solution was adopted by the European Union.

A. Suggestions for Future Work

Regarding the possibility of further investigation in the field of frequency regulation it would be extremely interesting to create a state of the art statistical model for wind speed, as for instance the one used in [19]. In this work it is considered that the wind speed is always high enough for the wind turbines to work at their rated power and no fluctuations of the turbines' power output are considered. The use of such a model would result in a series of values of power output for each turbine and it would allow to evaluate how the controllers used in this work react to such disturbances.

Furthermore, focusing more on the work developed in this study and being aware that each grid has its own dynamic, there are different optimal parameters for the APC and Virtual Inertia Controller, being of extreme importance to develop a method for finding the optimal tuning of the two controllers.

Last but not least, it would be interesting to make a comparison between the results obtained in this study using the European solution with the possibility of installing ESSs to contribute for frequency regulation.

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