The Need of Synchronous Inertia in Autonomous Power Systems with Increasing Shares of Renewables

The study case of Madeira Island's hybrid power system

Pedro P. Beires, MSc
INESC TEC (Institute for Systems and Computer Engineering, Technology and Science)
Porto, Portugal
pedro.p.beires@inesctec.pt

C. L. Moreira, PhD
University of Porto, Faculty of Engineering
INESC TEC (Institute for Systems and Computer Engineering, Technology and Science)
carlos.moreira@inesctec.pt

João Peças Lopes, PhD, FIEEE
University of Porto, Faculty of Engineering
INESC TEC
jpl@fe.up.pt

Agostinho G. Figueira
EEM – Empresa de Electricidade da Madeira
Funchal, Portugal
afigueira@eem.pt

***Abstract*—This paper focuses on the study case of Madeira Island, where the local system operator is expecting a large growth of the connected renewable generation sources in the upcoming decade. Future off-peak scenarios point towards dismissing thermal-based generation and therefore a dynamic stability study is required in order to assess the grid stability conditions under these circumstances. While stationary battery-based solutions can provide fast power-frequency regulation capabilities, the strict load shedding activation criteria typically used in this system require complementary measures to sustain frequency excursions resulting from severe grid faults. The performance of supplementary power-electronics-based solutions was evaluated, which proved to be unsuccessful as a result of the fast dynamics of the islanded system and to the difficulties on the modulation of active power injection during severe grid faults. Hence, there is the need of identifying a different approach to assure system stability, which involves the increase of synchronous inertia, specifically through retrofitting old thermal units to operate in synchronous condenser mode. The benefits of this grid supporting mechanism are demonstrated throughout extensive numerical simulations.**

Keywords - islanded power systems; grid stability; synchronous inertia; renewable generation integration

I. INTRODUCTION

Islanded power systems are aiming to continuously reduce their dependency from conventional generation, in order to avoid the heavy costs of fossil fuels, as well as reducing the environmental hazards of this generation type. These units are typically used to provide power-frequency regulation, consisting in the main rationale for the foundation of a classic autonomous power system. As the knowledge regarding power system operation with significant shares of renewable energy sources is growing, the integration of these units in islands is also continuously increasing. The increase of renewable energy sources in island power system has been requiring the identification of specific spinning reserve criteria, which together with the increasing quality of endogenous resources forecasting techniques is contributing to the secure operation of these power systems [1]-[3].

There are several examples of autonomous power systems where the share of fossil-fuel-fired generation has been notably reduced as the penetration of clean renewable energy has grown [4]. Following this trend line, the work presented in this paper is based on a study case for the Madeira Island, where the system operator expects a large growth of the renewable energy share, currently around 35% (2016), into more than 50% (up to 2030). Such high shares of renewables integration pose significant challenges to the local system operator in terms of dynamic system security. Specifically, this work approaches grid stability issues of a future planning scenario for the Madeira Island (reference year of 2025) with increasing amounts of renewable generation from distinct energy sources, as well hybrid energy storage based on reversible hydro pumping stations and battery-based storage facilities. Reversible hydropower storage is used for energy arbitrage while battery energy storage is intended for fast power-frequency control. For the planning horizon its peak demand is of approximately 100 MW while the valley load is about 60 MW. The foreseen operating scenarios involve near 100% renewable generation, the majority of which provided by wind and solar installations, focusing on off-peak and valley periods.

Under this planning scenario it is expected that a significant number of operation hours of the system will be performed without any thermal power stations connected to the grid. In this case, grid operation will rely on batteries and renewable energy sources, being dominated by power converters. These operating conditions is very demanding from the stability view point, thus requiring detailed dynamic simulations studies in order to identify the resulting shortcomings while considering relevant grid disturbances such as short-circuits.

One of the key issues regarding the dynamic security of this network is related to the need of avoiding underfrequency load shedding, which can be triggered either by the rate of change of frequency as well as by the frequency excursion. During the voltage sags, most of the power associated to converter-interfaced units is significantly affected due to the fault-ride-through reaction of the electronic interfaces, which is then followed by its ramp-limited active power recovery after the voltage is restored [4]. Therefore, the voltage sag and the residual voltages in the grid resulting from it significantly impact the active power, thus inducing large frequency transients in the system that may risk the activation of load shedding mechanisms.

In a primary stage of the study, several advanced grid supporting functionalities for the existing power converters were tested through dynamic simulations. These functionalities proved to be insufficient to sustain the fast frequency excursions that are expected for the system. Thus, it became clear that this system required complementary measures to reinforce its dynamic security conditions. From the performed studies and taking into account the fast frequency dynamics of the system, the need of adopting and sizing a system solution based on the increase of the synchronous inertia was identified in order to assure the dynamic security of the grid.

II. Study Case

As previously referred, this paper is based on a study case developed for the Madeira Island, a medium-sized island (741 km²) with a large variety of power sources. The practical application of the outcomes from this study is analyzed through a set of scenarios for expected for 2025, taking into consideration the power system development expectations from EEM *(Empresa de Electricidade da Madeira – Madeira Electricity Company)*, the system operator. This island's power system includes a transmission system operated at 60 kV and 30 kV, which integrates 29 substations. The monthly peak loads in 2016 varied between 115 and 145 MW. Table I summarizes the current state of the generation in this island, also including the share each source type had in the total power supply in 2016.

TABLE I. Power generation in the Madeira Island in 2016

Generation	Installed capacity [MW]	Energy share [%]
Diesel	112.6	55.0
Natural gas	54.4	14.6
Hydro	50.7	12.6
Wind	45.1	9.9
Solar PV	18.3	3.6
Waste-to-energy	8.0	4.3

In terms of hydro pumping, there are currently 7.4 MW of available capacity in operation. These hydro pumps are based on fixed speed units without fault-ride-through capability. As of 2016, 86% of the wind power installed capacity has fault-ride-through capability. In contrast, none of the solar units includes this functionality.

As previously mentioned, the local operator is expecting a large expansion of the generation system involving an ambitious growth of the installed capacity in renewables, a reduction of the thermal-based units and the integration of battery-based storage solutions. The following list summarizes the expected variations in the installed capacity by source type:

- *Hydro generation: increase to 110 MW;*
- *Hydro pumping: increase to 52 MW (separated pumps and hydro turbines are considered);*
- *Wind: increase to 103 MW;*
- *Solar: from increase to 78 MW;*
- *Fossil-fuel thermal: decrease to 67 MW;*
- *BESS: installation of 20 MW (one unit of 15 MW and another one of 5 MW).*

Regarding fault-ride-through capabilities, being a state of the art technology development in power electronic interfaced technologies, it is assumed that BESS, new wind and solar generators, as well as the new variable speed hydro pumps are capable of providing this grid supporting functionality, for periods greater than the fault clearance times typically measured in power systems of this size [3].

A. Expected Operating Conditions

As an illustrative example, Table II presents a typical operating scenario for off-peak hours, without the presence of thermal-based generation and considering the use of hydro generators fleet as synchronous condensers (105 MVA). This option constitutes a critical requirement regarding the need of providing adequate levels of short circuit power in the grid, as well as the need of proving voltage and frequency references for battery inverters to operate in the grid tied mode through a droop-based power-frequency modulation function. Also noticeable is the hybrid storage system integration achieved by pumped-hydro systems using separated pumps and turbines (for bulk energy storage) and the integration of 20 MW of Battery Energy Storage Systems (BESS) for fast power-frequency regulation purposes (one 15 MW unit and another with 5 MW connected to the grid in different substations).

TABLE II. Study case: Operating conditions

Generation	P [MW]
Diesel	–
Natural gas	–
Wind	58.4
Solar PV	53.0
Hydro	3.3
Waste-to-energy	4.8
BESS 5+15 MW	0.0 Ready
Total	**119.5**

Load	P [MW]
Consumer load	90.8
Hydro pumping	24.9
Transmission losses	3.8
Total	**119.5**

Table III summarizes the inertia constants of all synchronous units taken into consideration for these operating conditions. Note that all machines are associated to hydro power plants, except for MSR, which is part of the waste-to-energy facility.

B. Security constraints for the Madeira System

In islanded power systems, ensuring system security and robustness is usually associated to the need of avoiding load shedding occurrence as a consequence of excessive frequency deviations, as well as guaranteeing that the system returns to a stable point of operation within given security margins.

TABLE III. INERTIA CONSTANTS PER SYNCHRONOUS MACHINE

Machine	Inertia constant [s]	Rated power [MVA]	Inertia constant [s] [10 MVA base]
FDN G1	1.33	1.5	0.20
RDJ G2	1.33	2	0.27
SDA G2	1.02	3.6	0.37
CAV G2	0.7	1.41	0.10
CTAIII G1	2.83	20	5.66
CTAIII G2	2.83	20	5.66
CDR G1	1.02	5.5	0.56
CTI G1	0.69	8.8	0.61
SCR G1	2.83	10	2.83
SCR G2	2.83	10	2.83
SCR G3	2.83	10	2.83
MSR G1	0.8	11	0.88
		Total	**22.79**

This study aims to assess the dynamic stability conditions for future operating scenarios in the Madeira Island, excluding all fossil-fuel-fired units in off-peak periods. These units are characterized for providing power-frequency regulation, as well as contributing significantly to the system's inertia. The absence of these units creates a need to counterbalance the lack of spinning reserve. Integrating 20 MW of BESS in these future scenarios creates a significant amount of fast active power reserve in the system. However, this solution has two drawbacks. Firstly, these units do not add any inertia to the system, creating a substantial deficit when comparing with operating conditions with thermal-based power plants. The inertial response to grid disturbances provided by synchronous machines is a fundamental contribution to assist the system's recovery. Additionally, the fault-ride-through functionalities present remarkably different behaviors comparing to conventional synchronous generation. During voltage sags, the active power feed from converter-interfaced units will face heavy reductions and the subsequent recovery is not instantaneous, being often limited by predetermined gradients. The combination of both concepts leads to considerable active power deficits during and directly after grid faults, which causes greater frequency excursions [3].

Hence, the critical security constraint for the Madeira system is avoiding automatic under-frequency load shedding situations. Specifically, it is considered that load shedding occurs if the following conditions simultaneously take place:

- *Rate of change of frequency ($\Delta f/\Delta t$, RoCoF) lower than -1.5 Hz/s*
- *Absolute frequency value lower than 49 Hz*

In order to perform a security analysis the previously described operating conditions, three-phase short-circuits located in critical 60 kV and 30 kV lines were considered.

C. Relevant modelling notes for dynamic stability studies

To model the dynamic behavior of this island's power system and its individual elements, *MATLAB® Simulink®* was the adopted simulation software platform, using *Simscape Power Systems™* component libraries, along with a set of user-defined models that were considered for components whose grid connection is made through full-scale power electronic interfaces (wind generators, solar plants and variable speed pumping units).

The scenarios analyzed in this study aim to exclude thermal-based generation from system operation in off-peak hours, considering that the spinning reserve provided by these units in replaced by the fast regulation capabilities of BESS. Thus, the BESS are, in the considered scenarios, the only elements in the system operating with downward and upward power reserve, including primary and secondary frequency control. In fact, BESS are intended to provide grid power support during short periods and therefore, in normal operating conditions, they are connected to the grid with zero power flow.

The fleet of hydro generators is connected to the grid as synchronous condensers, being represented by a synchronous machine without mechanical power. In terms of voltage control, these units are assumed to be equipped with an automatic voltage regulator modelled by an IEEE Type 1 exciter model. A similar approach is used to the waste-to-energy generator, being the main difference the consideration of a constant mechanical power driving the generator.

The vast majority of wind and solar generators, as well as the variable speed hydro pumps, are elements interfaced to the grid through power electronics converters. As previously referred, these units were modelled using user-defined dynamic simulation models. To adopt custom simulation models two different approaches are feasible. The first approach is based on physical modelling, which consists on deriving dynamic models through the description of all the physical phenomena using differential equations. In this case, the main difficulty is defining all of the models' parameters. Alternatively, a different modelling approach for the user-defined models is approximating the component's dynamic response through simpler transfer functions that must be limited appropriately in terms of the obtained response. This was the authors' adopted modelling option. Such a modelling approach is intended to reflect the components' interaction with the grid, within a certain time interval, thus avoiding the exhaustive representation of all the physical phenomena that take place due to the associated complexity.

With such a large amount of power converter interfaced units in this islanded power system, it is particularly relevant to address their behavior across grid disturbances. As mentioned in the previous paragraph, a simplified modelling approach was adopted, centered in the interaction of these components with the grid. The main focus is given to their fault-ride-through behavior, as represented in [6] and [6] for wind turbines. For instance, considering ENERCON variable speed wind machines, as voltage drops below a certain threshold, the Zero Power Mode is activated and the machines inject zero active and reactive power. This functionality is considered for all wind generators in the system, as well as all other converter-interfaced units. This also includes variable speed hydro pumps, which can also perform similar functionalities, such as a zero-torque ride-through, as explained in [7]. All the aforementioned units also include an active power limiting gradient, which decisively influences their interaction with the grid in the post-fault period. These limiting gradients, slowing the power recovery from the low-power or zero-power fault-ride-through period, were defined in an early stage of this dynamic stability study, reflecting a sensitivity analysis performed to optimize the system recovery subsequent to grid faults, and were considered as follows:

- *Wind generators: 2 MW/s;*
- *Solar generators: recovery within 0.5s (gradient variable by facility);*
- *Variable speed hydro pumps: 2 MW/s.*

III. Measures for Increasing System Security

As it was previously discussed, the key concern related to the Madeira Island electric power system security is related to the frequency behavior and the corresponding risk of under-frequency load shedding. This is notorious, given the expected operating scenarios with no thermal based generation, as the fast power-frequency regulation should be performed through stationary batteries. Additionally, the system operation largely relies on the synchronous condenser operation mode of hydro generation in order to provide the grid and voltage frequency waveform such that battery energy storage systems can synchronize to it and operate in the grid tied mode. Under these challenging operating conditions, it is anticipated that adverse security concerns will occur in the system. In line with the local system operator, the following possible solutions were identified and its feasibility was evaluated through dynamic simulation of the systems:

- Increasing the installed capacity of BESS. The future investments in this power system foresee the installation of this technology in two different sites, with 15 and 5 MW of installed capacity respectively. This measure specifically consists in increasing each system's capacity proportionally. Two distinct capacity levels were evaluated, first with a total of 30 MW and afterwards with 40 MW.
- Adding a supercapacitor to the system, namely through a device peaking around 12 MW during 5 s, gradually decreasing to zero afterwards..
- Increasing the synchronous inertia in the system. This can be accomplished for instance by connecting additional synchronous condensers to the system or by increasing the inertia constants of existing units through flywheels to be mechanically connected to the shaft of rotating machines. The chosen solution was to retrofit diesel units to be decommissioned in the future, making them able to operate as a synchronous condenser and, considering a supplementary increase of the units' inertia. Table IV provides an overview of the variations in the global inertia that was considered with this solution.

IV. Simulation Results

This section presents a summary of the most relevant simulation results obtained regarding the previously presented a typical off-peak operating scenario (as in Table II), in which some grid disturbances were considered attempting to expose the system to severe dynamic security stresses. In particular, this summary focuses on two overhead line short-circuits in each of the operated transmission network levels (60 kV and 30 kV). These disturbances cause large voltage dips, leading to the disconnection of undervoltage-sensitive assets and the activation of fault-ride-through modes in most of the power converters connected to the system, among other consequences. Besides ensuring that the system recovers to a stable point of operation, the pre-established load shedding criteria need to be monitored, starting in the primary level which is triggered at a rate of change of frequency of -1.5 Hz/s at an absolute value of 49 Hz.

TABLE IV. Additional inertia provided by retrofitted diesel units

	Diesel units* retrofitted for synchronous condenser operation			Total inertia [s] [10 MVA base]	Increase vs. default
	G1	G2	G3		
Inertia constant H [s]	-	-	-	22.8	0%
	1.5	-	-	25.8	+13%
	1.5	1.5	-	28.8	+26%
	1.5	1.5	1.5	31.8	+39%
	3.0	-	-	28.8	+26%
	3.0	3.0	-	34.8	+53%
	3.0	3.0	3.0	40.8	+79%
	4.5	-	-	31.8	+39%
	4.5	4.5	-	40.8	+79%
	4.5	4.5	4.5	49.8	+118%
	*Rated power = 20 MVA				

A. High-voltage transmission line short-circuit

Firstly, a symmetrical three-phase short-circuit located in one of the longest transmission lines of this island's high voltage (60 kV) network was simulated – disturbance A. The fault is cleared within 100 ms together with the disconnection of the line, leading also to the disconnection of several units without fault-ride-through capability. This refers to older wind and PV units, adding up to 20 MW of a combined generation loss, as well as fixed speed hydro pumps, partly counterbalancing this deficit with the disconnection of about 8 MW of load. Figure 1 presents the simulation outcome of the "base case", where no additional measures are considered.

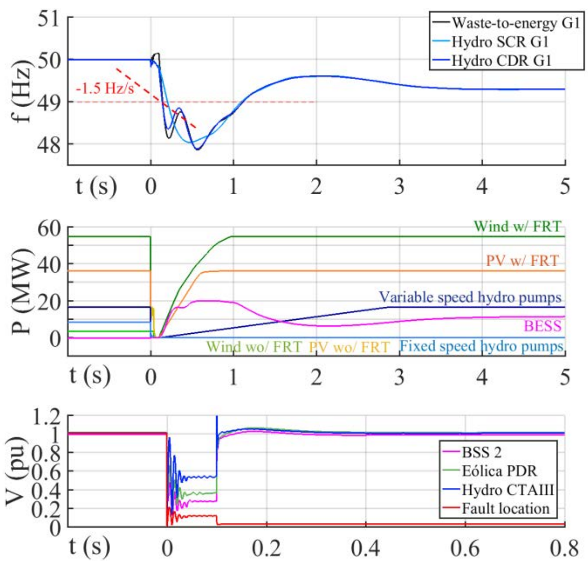

Figure 1. Simulation results for disturbance A, without any additional measures. Plots: frequency (top), active power (middle), voltage (bottom). The dashed red line indicates the primary load shedding criterion.

The active power unbalance caused by the disturbance leads to a significant frequency excursion, violating the load shedding criterion. It is made clear that there is need to act in the moments immediately after the fault, through a quick active power increase in the system. The first attempt is made by increasing the installed capacity of BESS, being the obtained results represented in Figure 2.

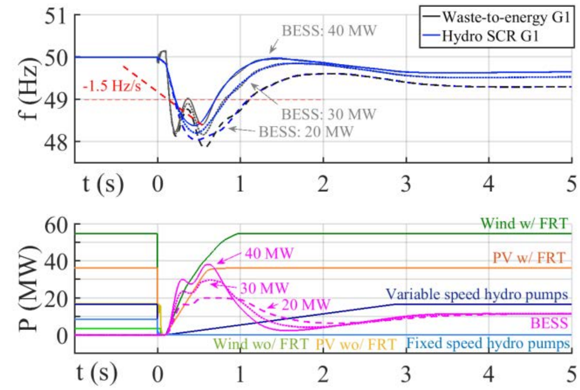

Figure 2. Simulation results for disturbance A, considering an increase in the installed capacity in BESS. Plots: frequency (top), active power (bottom).

As a consequence of the considered network fault, the BESS enter fault-ride-through and its active power response capacity in the initial moments is significantly affected: as a result of the voltage sag, the BESS converters reach the current limit and the injected active power is proportional to the amplitude of the voltage sag. Consequently, the influence resulting from the capacity increase in the BESS is negligible regarding the fast dynamics observed in the initial frequency drop. This solution only has some effectiveness after the fault clearance, when the grid voltage has recovered to stable values. It becomes clear that converter-interfaced units will face similar challenges, as the voltage sag is spread out across this small islanded network. Therefore, the next step is evaluating the increase of the system synchronous inertia, using the aforementioned solution of retrofitting decommissioned diesel units.

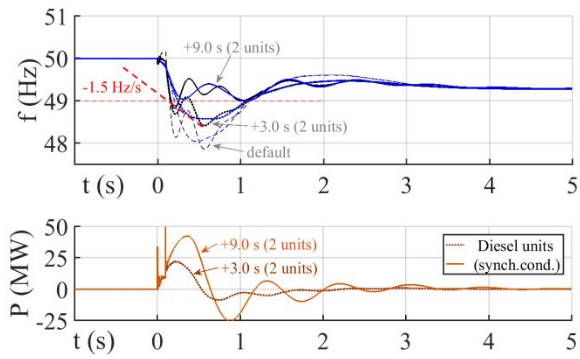

Figure 3. Simulation results for disturbance A, considering an increase of the system inertia by retrofitting two diesel units for synchronous condenser operation. Plots: frequency (top), active power (bottom).

The improvements provided by the additional inertia are remarkable, as the initial frequency drop is significantly sustained. The active power is quickly available, reflecting the accumulated kinetic energy in the synchronous machines' rotors, delivered to the system as the disturbance occurs.

Finally, a comparative plot of several simulations is presented in Figure 4, to emphasize the inefficiency of converter-interfaced solutions within this scope. Based on a simulation where three additional synchronous machines are connected (retrofitted diesel units), two additional situations are presented, one including additional BESS capacity and the other considering the 12 MW supercapacitor which was presented in Section III.

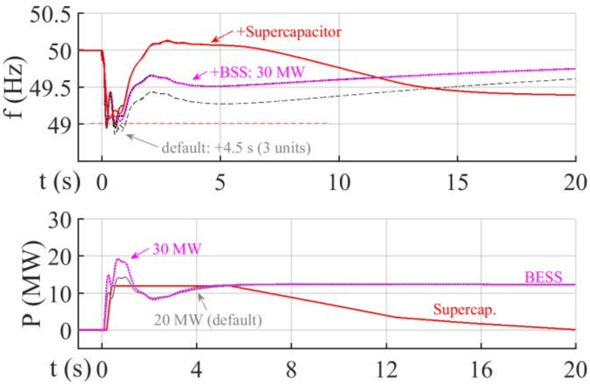

Figure 4. Simulation results for disturbance A, comparing the outcome in three situations, always considering an increase of the system inertia by retrofitting two diesel units for synchronous condenser operation. The base case (as in Figure 3), an increase in the BESS capacity and installing a supercapacitor. Plots: frequency (top), active power (bottom).

The results support the previously referred conclusion: The solutions involving power electronics converters do not provide the immediate benefits in the frequency excursion due to the large frequency decays induced by voltage sags that trigger the fault ride through mode in power electronic interfaced units. However, approximately one second after the disturbance the differences are tremendous, as these devices contribute with additional active power. The supercapacitor solution temporarily provided the best result, but as this unit dropped its power output, the frequency dropped accordingly as well.

B. Medium-voltage transmission line short-circuit with subsequent generation loss

The next disturbance to be considered was a short-circuit located in an overhead line of the secondary transmission system of this island – the medium voltage network which is operated at 30 kV. This line connected a wind park to the grid, meaning that this facility will be disconnected after the fault is cleared, which occurs within 200 ms – disturbance B. Due to the voltage sag, several undervoltage-sensitive units were quickly disconnected, namely older wind and PV generators, just like the fixed speed hydro pumps. Considering the loss of all these units, the total post-fault generation deficit is approximately 17 MW. Figure 5 presents the obtained results, considering no complementary dynamic security measures.

This disturbance results in a severe frequency excursion, dropping as low as 47 Hz. The need for additional inertia is more significant, comparatively to disturbance A, as the depth of the initial frequency decay is more pronounced. Figure 6 depicts the simulation results when considering additional synchronous condensers for increasing system inertia, through the aforementioned solution of retrofitting decommissioned diesel units.

For the system's response to be approximately valid (regarding load shedding criteria), 3 additional synchronous units with considerable inertia constants (4.5 s) had to be included. However, the security margins of these results are very small, pointing to the hypothesis that the load shedding criterion is excessively strict. More simulations were carried out, taking into account the converter-interfaced solutions that were already analyzed previously – a 50% increase in the BESS capacity (+10 MW) and the 12 MW supercapacitor solution (see Figure 7).

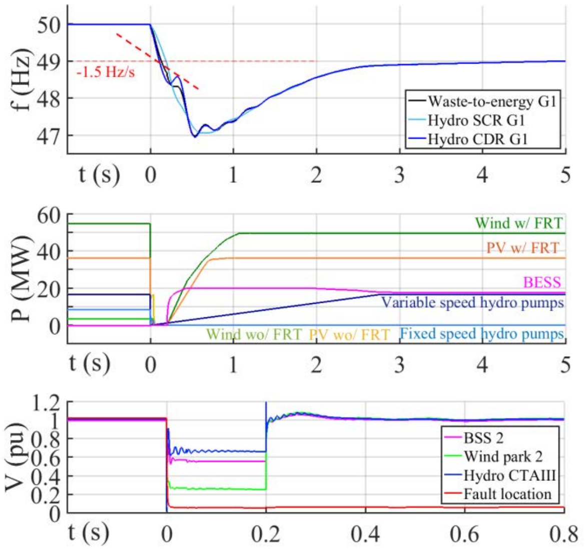

Figure 5. Simulation results for disturbance B, without any additional measures. Plots: frequency (top), active power (middle), voltage (bottom).

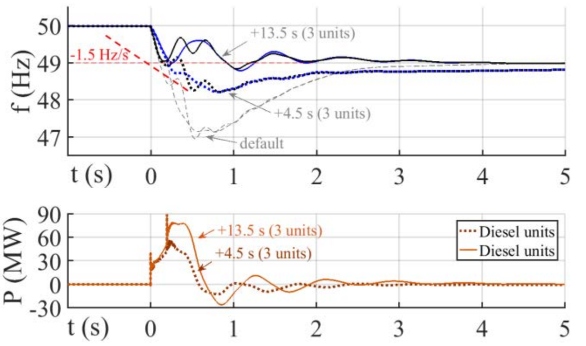

Figure 6. Simulation results for disturbance B, considering an increase of the system inertia by retrofitting three diesel units for synchronous condenser operation. Plots: frequency (top), active power (bottom).

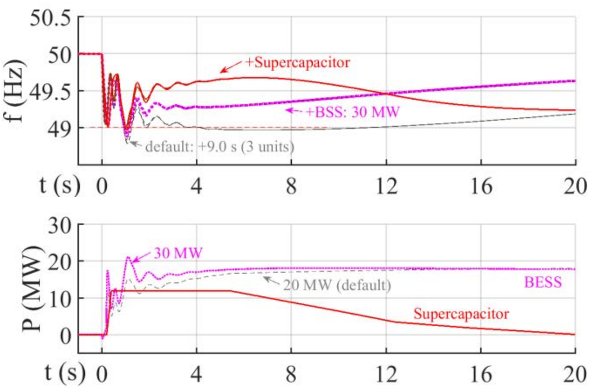

Figure 7. Simulation results for disturbance B, comparing the outcome in three situations, always considering an increase of the system inertia by retrofitting three diesel units for synchronous condenser operation. The base case (as in Figure 6), an increase in the BESS capacity and installing a supercapacitor. Plots: frequency (top), active power (bottom).

Once again, the results in Figure 7 demonstrate that the initial frequency drop is not sustained by the complementary frequency regulation mechanisms. However, a few seconds after this phenomenon there are visible differences between the different solutions.

V. CONCLUSIONS

This study focuses on hybrid islanded power systems, namely analyzing an off-peak scenario featuring very high renewable energy integration in which it is possible to identify potential operating conditions without thermal-based generation. The absence of these units leads to a significant lack of power-frequency regulation in the grid, partly outbalanced by the integration of battery-based systems. These operating conditions are also characterized by a significant deficit of synchronous inertia, which is a fundamental element of a power system's response to disturbances. Such a generation portfolio may expose the system to security issues, namely the unwanted load shedding situations, as frequency drops and its rate of change tend to suffer larger variations. To address these issues, complementary measures were evaluated through dynamic simulations.

From the obtained results it is clearly demonstrated that, during the voltage sag, power electronic interfaced units have a limited capacity for active power processing, thus limiting their effect on the improvement of the grid frequency response, in particular the rate of change of frequency. This does not avoid the previously mentioned load shedding situations, particularly in the case of this power system where the operator has set constraining load shedding criteria.

Hence, complementary solutions based on increasing the physical inertia connected to the system were identified in order to cope with the grid frequency behavior. These consist in retrofitting old thermal-based generators, making them able to operate as synchronous condensers and coupling flywheels to their rotating axes. The fast transformation of the accumulated kinetic energy in electric power is by far the most effective mechanism to sustain the frequency excursions following grid faults. Additionally, this solution allows for an extended use of existing facilities, although it requires a supplementary investment.

Conclusively, the outcome of this study emphasizes that a secure system operation in these scenarios can be performed without thermal-based generation, relegating this type of units for a backup level, thus contributing to reduce the dependency these power systems face regarding fossil fuels.

ACKNOWLEDGMENTS

The authors wish to thank EEM – *Empresa de Electricidade da Madeira, S.A.* (Madeira network operator) for granting permission for their system's study case to be presented in this paper.

This work was financed by the ERDF – European Regional Development Fund through the Operational Programme for Competitiveness and Internationalization - COMPETE 2020 Programme and by National Funds through the FCT – *Fundação para a Ciência e a Tecnologia* (Portuguese Foundation for Science and Technology) within projects «SAICTPAC/0004/2015- POCI-01-0145-FEDER-016434» and «ERANETLAC/0005/2014».

REFERENCES

[1] P. Komor, J. Glassmire, “Electricity Storage and Renewables for Island Power - A Guide for Decision Makers”, IRENA (International Renewable Energy Agency) Technical Report, May 2012.

[2] K. Hedegaard, P. Meibom, “Wind power impacts and electricity storage – A time scale perspective, Renewable Energy”, Vol. 37, Issue 1, pp. 318-324, January 2012, ISSN 0960-1481,

[3] P. Beires, M. H. Vasconcelos, C. L. Moreira, J. A: Peças Lopes “Stability of autonomous power systems with reversible hydro power plants” Electric Power Systems Research, Vol. 158, May 2018, pp. 1-14

[4] E. M. G. Rodrigues, G. J. Osório, R. Godina, A. W. Bizuayehu, J. M. Lujano-Rojas and J. P. S. Catalão, “Grid code reinforcements for deeper renewable generation in insular energy systems”, in Renewable and Sustainable Energy Reviews, Elsevier, 2016, pp. 163-177

[5] N. Taveira, Â. Mendonça, E. Quitmann, C. L. Moreira, B. Silva, J. Moreira , C. Pereira da Silva, "The connection studies for 1200 MW wind power integration in Portugal", 11th Wind Integration Workshop, Lisboa, Portugal, November 2012.

[6] S. M. Muyeen, R. Takahashi, T. Murata, and J. Tamura, “A Variable Speed Wind Turbine Control Strategy to Meet Wind Farm Grid Code Requirements”, IEEE Transactions on Power Systems, Vol. 25, Issue 1, pp. 331-340, 2010.

[7] T. Wymann, P. Jörg, “Power Loss Ride-Through In A Variable Speed Drive System”, ABB Medium Voltage Drives, Switzerland, 2014.