Frequency Response of Synchronous Generators and Battery Energy Storage Systems: A Comparative Study

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***Abstract*—In this paper, a comparison of power system frequency response is conducted for a simple modelled power system with primary frequency control being provided either by synchronous generators or by inverter-based Battery Energy Storage (BES) systems. Mathematical models of conventional governor and turbine are developed, representing conventional synchronous generator frequency control, and are used to illustrate system frequency response for a range of typical conventional generating units. A mathematical model of a power-electronics interfaced Li-ion BES system is developed and used to represent a non-synchronous inverter-based generator with primary frequency control capabilities. MATLAB/Simulink is used to build a model of a small power system, and simulations are carried out with at a range of typical conventional synchronous generating units with a non-synchronous generating unit in the power system. The simulation results demonstrate that the BES can be used for primary frequency control providing a faster and better response. BES is also capable of almost eliminating frequency overshoot and reducing 70% of settling time while providing primary frequency control in power system with various types of conventional synchronous generating units and a non-synchronous generating unit.**

Keywords—frequency control, battery energy storage, conventional, non-conventional, rate-of-change of frequency

I. INTRODUCTION

The integration of increasing levels of Renewable Energy (RE) based non-synchronous generation (wind and photovoltaics for example) into the power system is occurring via the replacement of conventional synchronous generation sources. As a result, power systems are becoming more dynamic in nature, owing to loss of system inertia [1]. In case of any imbalance between generation and load, the Rate-Of-Change of Frequency (ROCOF) is significantly higher in a system with low-inertia. Therefore, control of frequency in a system with high penetration of RE needs to be more faster than the system with higher inertia [2].

The amount of inertia in the power system at a particular time depends upon the number of synchronous generators in active operation, and upon their inertia constants. Total system inertia decreases with increasing level of non-synchronous RE generation, since synchronous generators are displaced from active operation. Because the instantaneous penetration level of RE in a system is a function of resource availability (e.g., wind speed, solar irradiance), the composition of synchronous and non-synchronous generation can vary considerably with time, consequently changing the total inertia of the power system on relatively short timescales [3-5].

Germany's power system provides a good early example of a system containing high levels of non-synchronous generation. The time-varying inertia of Germany's power system is computed for the year 2013 and presented based on an aggregated system model in [1]. Fig. 1 illustrates considerable fluctuations of the aggregated inertia constant for the German system over the last quarter year of 2013, showing, for example, a reduction of almost half over a period of two days (two highlighted points in Fig. 1).

Several methods have been developed to improve the performance of frequency control using Energy Storage Systems (ESSs) in the power system with low-inertia during high RE penetration. For the primary frequency control ancillary services, ESS with fast response characteristics is required to obtain quick response when a frequency event occurs. Fig. 2 shows the application of ESS in terms of response time in the power system.

Pumped-Hydro Storage (PHS) system is used in primary frequency control ancillary services in the system described in [6]. Although, the nature of the operation of PHS systems means that they mainly involve in energy management in the fields of time-shifting, non-spinning reserve and supply reserve in the power system [7]. However, with the limit of site selection, PHS plants have disadvantages of long construction time and high capital investment. Another method which has been developed to enhance the performance of primary frequency response is Compressed Air Energy Storage (CAES) using two sets of motor and generator configuration in a CAES system modelled in [8]. The main disadvantages are the friction between rotor and shaft affecting the system efficiency, suitable geometric location of CAES systems and the high costs [9]. In order to achieve a fast-primary frequency response, BES is used in the power system described in the [10]. Li-ion BES has quick response and nearly 90 percent of efficiency, so, it is considered as a good selection for primary frequency control ancillary

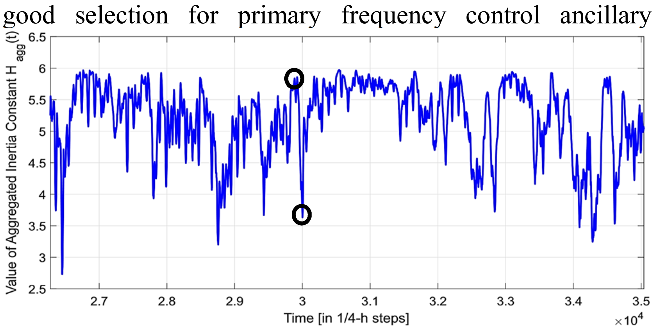
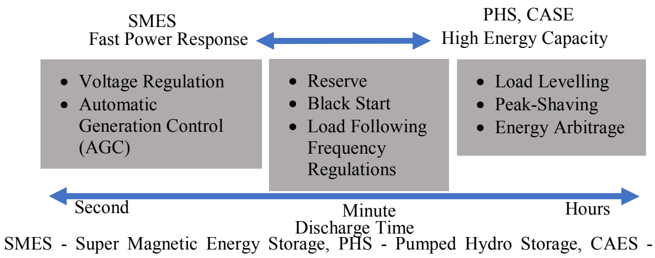


Fig. 1. Temporal variation of the aggregated inertia in Germany for the last quarter of 2013[1].



SMES - Super Magnetic Energy Storage, PHS - Pumped Hydro Storage, CAES - Compressed Air Energy Storage

Fig. 2. Application of ESS and timing of functions

services of power system [11]. The key disadvantages of Li-ion battery are the cycle Depth of Discharge (DoD) that can affect the Li-ion battery's lifetime and the battery pack, which usually needs an on-board computer to manage its manoeuvre. However, the repetitive charge and discharge of BES to the primary frequency control cause to drastically deteriorate its lifespan and cycle-efficiency.

In this paper, a comparative study of the primary frequency response of the power system with combination of synchronous and non-synchronous generation is investigated, utilising BES for primary frequency control. The behaviour of the primary frequency response is investigated when BES is employed for primary frequency control in the system with a range of types of conventional synchronous and non-synchronous units. MATLAB/Simulink is employed to develop a model of a small power system, with frequency response performance evaluated by observing frequency nadir, ROCOF and frequency settling-time following a frequency disturbance. Initially, the response to an increased step-load is investigated for a system consisting of two synchronous generation units with primary frequency control action provided by one unit, exploring the impact of a range of different governor and turbine response times. Subsequently, the synchronous generator with primary frequency control is replaced by BES employing primary frequency control, and frequency response performance with the different combinations of synchronous and non-synchronous generation is investigated.

The remainder of the paper is organised as follows. The conventional power system and its frequency control techniques are discussed in Section II. BES dynamic modelling for primary frequency control is briefly reviewed in Section III. The simulation results and discussion on the performance of the primary frequency response of synchronous and non-synchronous generations are presented in Section IV, followed by a conclusion presented in Section V.

II. Conventional Primary Frequency Control in Power System

In a conventional synchronous generation system, the prime mover is a source of mechanical power, for example a hydraulic turbine driven by the flow of water in a hydro power plant, or a steam turbine whose energy comes from burning coal or gas, or the reaction ofnuclear fuel. Therefore, the response of the governor and turbine of a conventional synchronous generating unit with a primary frequency controller and the total inertia of the system exhibit the characteristics of primary frequency response in the power system. In a power system under steady-state operating conditions, the output of all generators is equal to the total system load plus losses. However, when the electrical load changes, an imbalance between generation and load occurs in the power system. All operating synchronous generators supply or absorb the deficit or surplus power required to balance the system, by reducing or increasing accordingly the amount of stored energy associated with their rotational mass[12]. This fast response of the system is known as inertial response. The inertial response of the system is both proportional to and the determinant of the ROCOF. This inertial response typically lasts for up to 10 seconds, depending on the total inertia of the system, the size of the generation/load imbalance[13], and the subsequent frequency response of generators in the system. The ROCOF can be realised by swing equation in [14].

$$\frac{d\Delta\omega}{dt} = \frac{\omega_0}{2H_{sys}S_b}(\Delta P_m - \Delta P_e) \qquad (1)$$

where, ω_0 is the nominal frequency of the system, ΔP_m and ΔP_e are the mechanical powers input and electrical powers output, respectively, and S_b is the base electrical power rating of the system. The aggerated inertia constant of the system can be represented by H_{sys}. It is obvious from (1), the ROCOF is higher with smaller H_{sys}, when less kinetic energy stored in the rotating mass. The typical range of inertia constant and governor and turbine time constants for steam turbines, Combined-Cycle Gas Turbines (CCGT) and hydro generating units are given in Table I. The inertia constant of CCGT is almost double that of steam and hydro units, while the time constant of the hydro unit is twice of the steam turbine. The block diagram of Fig. 3 [12] represents a typical frequency controller with proportional (droop) control. When a change in system load or generation occurs, frequency changes. Therefore, the governor position ΔP_g is adjusted to a new value to regulate the valve position of turbine ΔP_v, which can be modelled as a first-order response with time constant of

TABLE I. Inertia constant of the different generating unit.

Generating Unit	H_{sys} (MW.s per MVA)	Time Constant
Steam	2.5 – 6 [14]	Governor ~ 0.2 – 0.4 s [14] Turbine ~ 0.3 – 0.7 s [14]
CCGT	4 – 10 [14]	Governor ~ 0.3 – 0.5 s [15] Turbine ~ 0.4 – 0.9 s [15]
Hydro	2 – 4 [14]	Governor ~ 0.4 – 0.52 s [14] Turbine ~ 0.5 – 1.02 s [14]

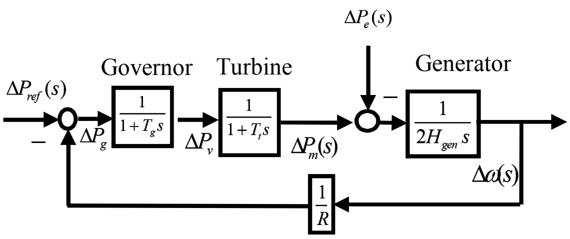


Fig. 3. Typical primary frequency controller of a power system.

governor T_g. Consequently, the level of mechanical power presented to the generator ΔP_m changes according to the first-order response of the turbine, with time constant T_t. The characteristics of change of power output of the generator as the system frequency change are known as speed-droop characteristics or speed-governor characteristics. The well-established method of frequency control is called droop control, with the coefficient of droop control denoted by R. The speed-droop (speed regulation) characteristic can be obtained by adding a steady-state feedback loop around the governor and the turbine as shown in Fig. 3. The value of droop coefficient R determines the steady-state speed versus load characteristics of the generating unit. The droop control loop of the governor acts on the change in the frequency and changes the position of the governor valve to change the turbine's output. This is a slower response than inertial and it depends on the dead-band of the governor and time lag of the turbine. The preliminary action is taken by the governor and turbine to change the generator input reference when the frequency changes known as primary frequency control. Depending on the droop curve slope and the generator size, the active power participation of each generator in primary frequency control could be different. This droop control strategy does not require a communication network to share the frequency information. However, coordination among the generating units ensures the schedule of droop slopes for each primary frequency control participating generating unit in the power system.

The characteristics of ROCOF depend on the total inertia of the system, while the amount of inertia varies due to the properties and capacity of synchronous generation units. When the disbalance occurs between load and generation in the system, the response of generation depends on the time constant of the governor and turbine of the synchronous generation units. The steady-state feedback loop with droop coefficient R or speed-droop characteristics regulates the level of generation considering change of system frequency.

III. BES Dynamic Modelling

A BES is modelled to represent a non-synchronous generating unit and used to provide primary frequency control support. In this paper, a typical Li-ion battery is modelled, and its dynamic characteristics of charging and discharging are adopted in the power system. The effect of temperature and ageing are not considered in this model. The most common model is Shepherd model [16] which directly shows the characteristics of electrochemical response of the battery. The following expression presents the model mentioned:

$$E_{batt} = E - Ki^* \frac{Q}{Q-i(t)} - Ki(t)\frac{Q}{Q-i(t)} + A\, \mathrm{e}^{\{-B\, i(t)\}} \quad (2)$$

where, E_{batt} and E are the battery terminal voltage and battery internal voltage or no-load battery voltage, respectively. K represents battery polarization resistance. Q is maximum capacity of battery measured in (Ah). The extracted capacity of the battery $i(t)$, measured in (Amp-sec). The i and i^* are battery current and low-frequency battery current dynamic, respectively. The A and B denote the exponential voltage (V) and exponential capacity (Ah^{-1}), respectively.

The charging and discharging equations of different batteries are similar to each other [17], however, lithium-ion batteries have a special exponential dynamic charging and discharging model. The no-load battery voltage E is constant regardless the State-of-the-Charge (SOC) of the battery. In this paper, the Li-ion battery model is adopted to a constant voltage source and capable of providing primary frequency control services for the required period for the modelled power system for simulation results.

IV. Simulation Results and Discussion

Two different case studies have been designed by MATLAB/ Simulink to analyse the primary frequency response. Case Study 1 is outlined for primary frequency provided by synchronous generation units, and Case Study 2 is for BES. For both cases, increased step-load is used to analyse the performance of primary frequency response by observing ROCOF, maximum frequency droop known as frequency nadir and frequency settling time. The ROCOF can be measured at the different period after the frequency event [18, 19]. In this paper, 500 ms [18-20] window is considered to measure the ROCOF. The frequency settling-time determines the period between when frequency contingency event occurs and at the time when the frequency is less or greater than 0.01% of the final value of the frequency after the primary control action [21].

A. Case Study 1: Synchronous Generations as a Primary Frequency Controller

Case Study 1 is designed to analyse the primary frequency response of different synchronous generation units in a power system. A simple, small power system, shown in Fig. 4, consists of two generators, Generator-A and Generator-B, and two loads, Load-A and Load-B. Generator-A has primary frequency control enabled according to the governor and

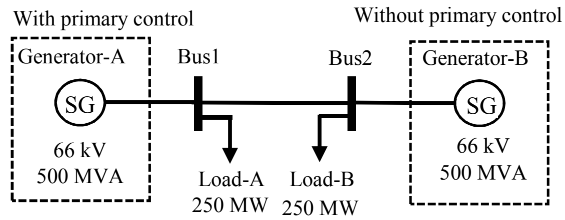


Fig. 4. Simple power system model, with two generators connected to loads.

turbine control method referred to in Fig. 3, and Generator-B has a constant input without primary frequency control. Both generators have same inertia constant of 4 s and are of the same rated power. To investigate the different frequency response characteristics for different types of generators, a range governor and turbine time constants are used in simulations, covering the three types of common generating units described in Table I. In this paper, it is assumed that there is no dead-band of inlet-governor valve position for steady-state primary frequency control operation.

Frequency characteristics are observed by creating a contingency event (a large step change in load) in the modelled power system and observing the system and generator response. In each simulation, initially Load-A is 250 MW and is supplied equally by Generator-A and Generator-B (125 MW each). The step-change in load is achieved by introducing the 250 MW of Load-B. According to the National Electricity Market (NEM) after the contingency event, frequency range should be 49.5 Hz to 50.5 Hz [22]. To meet the requirement, the value of R should be equal to or larger than 25. Therefore, the primary control droop coefficient of Generator-A is set to R=25 for all simulations. For the range of the turbine and governor time constants used in these simulations, the resultant ROCOF, frequency settling time and frequency nadir are plotted in Fig. 5, Fig. 6 and Fig. 7, respectively. As shown in Fig. 5, the steam unit has comparatively lower ROCOF because of a faster response of steam turbine than the typical hydro and the CCGT units.

The conventional CCGT and the hydro units have longer turbine and governor response times than the steam unit. Therefore, the frequency settling-time is comparatively longer for the CCGT and hydro generators than the steam unit, as illustrated in Fig. 6. Since the combined time constant of hydro is generally in the order of twice that of steam and CCGT, the primary frequency response provided by a steam or CCGT unit is faster than that provided by a typical hydro unit. As a result, when primary control is provided by hydro the power system sees a lower frequency nadir (larger frequency excursion) compared to when frequency is controlled by equivalently sized conventional CCGT or steam generator, as shown in Fig. 7. Frequency nadir refers to a minimum frequency reached after a frequency contingency event occurs when step-load increased.

The performance of the primary-response provided by different synchronous generation units depends on their governor and turbine response time. The primary-response provided by the steam and CCGT is comparatively faster than the primary-response provided by the hydro unit. Therefore, the system with the primary-response of the steam and CCGT has improved ROCOF, frequency settling-time and frequency nadir than the primary-response of the hydro unit.

B. Case Study 2: BES-Inverter as a Primary Frequency Controller

Case Study 2 is designed to analyse the primary frequency response of BES-inverter for a range of typical conventional synchronous and non-synchronous generating units in the power system. A simple power system, shown in Fig. 8, is modelled, to investigate the effectiveness of the inverter-based generating units, and their frequency response is compared with different typical types of synchronous generating units. In this model, a BES-connected inverter provides primary control in response to a step change in load, replacing the functionality previously provided by Generator-A in Case Study 1. Replacement of the synchronous generator with BES-inverter results in the total inertia of the system being halved compared to the system modelled in Case Study 1. The primary frequency response of the system is analysed for a range of typical conventional generating unit types, by varying the inertia constant H of Generator-B. The droop coefficient R of the BES-inverter's primary frequency controller is also varied in order to assess response characteristics for different inverter control settings. Key frequency response characteristics such as ROCOF and frequency settling-time are investigated. Since droop coefficient R impacts both the frequency nadir and final frequency after a contingency event, frequency overshoot is also assessed. The frequency overshoot, F_{os} can be calculated by taking the value of minimum/maximum frequency, $F_{min/max}$ and finalfrequency, F_{final} after the primary frequency control action, as expressed below:

$$F_{os}(\%) = \left|\frac{(F_{min/max} - F_{final})}{(F_{final} - F_0)}\right| \times 100 \qquad (3)$$

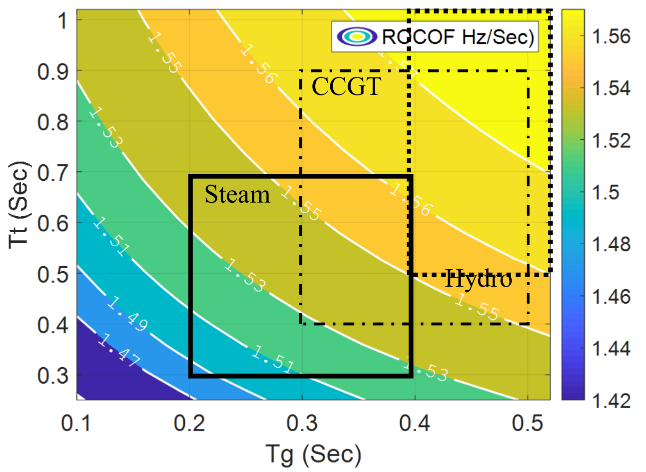


Fig. 5. ROCOF measured at 500ms after load change for different governor and turbine time constants.

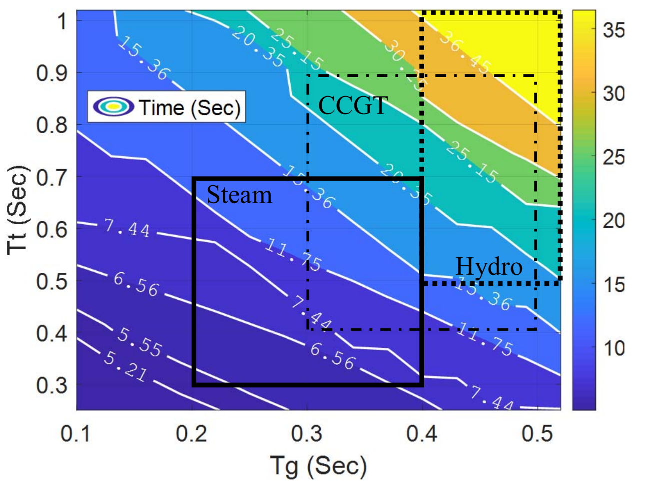


Fig. 6. Frequency settling time for different governor and turbine time constants.

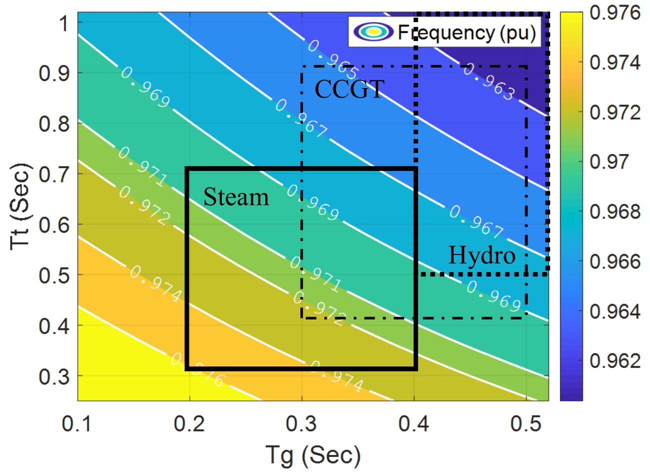


Fig. 7. Frequency nadir for different governor and turbine time constants.

where F_0 is system nominal frequency.

For Case-Study-2, and initial Load-A of 250 MW is supplied by Generator-B (125 MW) and the BES-inverter (125 MW). A step Load-B, 250 MW, is added to the power system at t=35s. A Li-ion battery of 6 kAh, 480 V, 80 % SOC is chosen for the simulation. A three-phase step-up transformer is used to connect the battery to the 66 kV bus in the system.

As the BES-inverter replaces with SG, the inertia of the system being halved compared to the system modelled in Case Study 1. As a result, the ROCOF is higher in the system with smaller inertia constant, as shown in Fig. 9. Furthermore, the value of the droop coefficient has a less contribution to the improvement in ROCOF in the system when BES is employed for primary frequency response.

As the BES is connected to the grid via high-speed power electronics devices, the BES-inverter is faster than the conventional synchronous generation units in terms of primary frequency control. Therefore, considering Fig. 10, the frequency settling-time is improved in the system with BES-inverter as the primary frequency response. The frequency settling-time is increased in the system with a smaller value of the droop coefficient of the BES-inverter and higher inertia constant, as shown in Fig. 10. However, at the droop coefficient of 28 and above, the inertia constant of the system has less impact on the frequency settling-time. This is because the droop coefficient is large enough to enable rapid injection of active power into the system when the load increases. Frequency-overshoot decreases in the system with higher inertia constant of Generator-B shown in Fig. 11. However, the higher value of the droop coefficient of BES-inverter significantly increases the frequency overshoot when the system has low-inertia.

The ROCOF, frequency settling-time and frequency nadir or frequency-overshoot can also be directly compared for different scenarios, by examination of the detailed dynamic system frequency responses. The system frequency after a step-load change, and for four such scenarios is shown in Fig. 12. In each scenario, Gen2 is a synchronous generator studied in Case Study-1 and providing system inertia, but with varying inertia constant, and no frequency control. Gen1 is a synchronous generator, with primary frequency control enabled and having governor and turbine time constants of 0.4 s and 0.7 s respectively, thus representing a steam turbine and generator. Inv is the BES-Inverter studied in Case Study-2 varying inertia constant of Gen2. A droop coefficient of R=25 is used for primary frequency control, both for the Gen1 and for Inv. System inertia constant, indicated in the figure, is owing to the combined inertia of the generators.

It is evident that the frequency nadir for the two SGs scenario is nearly as low as 48.25 Hz, with frequency taking about 20 s to settle at a final value of 49 Hz. However, with the inverter replacing Gen1's primary frequency control functionality, the response is considerably improved, even with the resulting reduction in system inertia. Since the inverter is a power electronic device, it is able to swiftly inject active power into the system after the contingency event, and so the frequency is settled at 49 Hz rapidly and with little or no overshoot or oscillation. Due to avoiding the delay caused and turbine, the inverter operates comparatively quicker than the synchronous generating unit.

Meanwhile, the frequency oscillation due to the inertial and primary-response of the synchronous generation unit is reduced with the inverter primary frequency control. To study the impact of the different combination of the synchronous

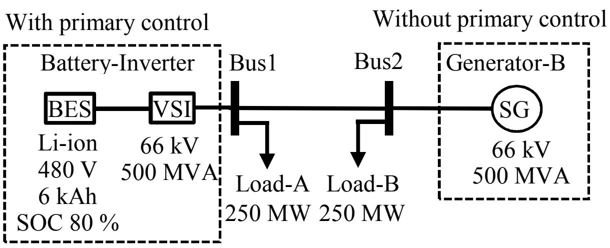


Fig. 8. A battery-inverter representing non-synchronous generating unit equipped with primary frequency control is connected to Generator-B in the power system.

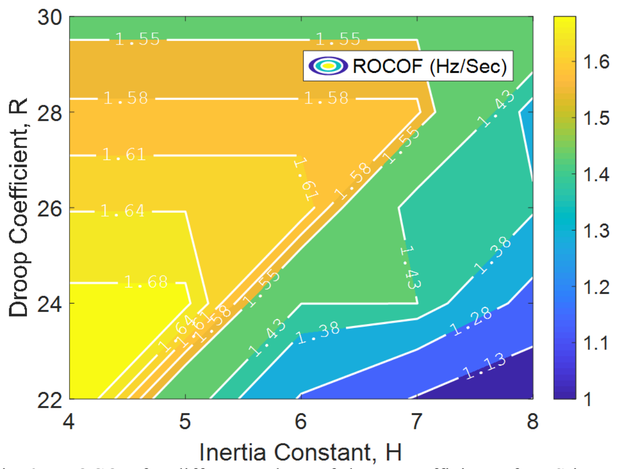


Fig. 9. ROCOF for different values of droop coefficient of BES-inverter and inertia constant of SG.

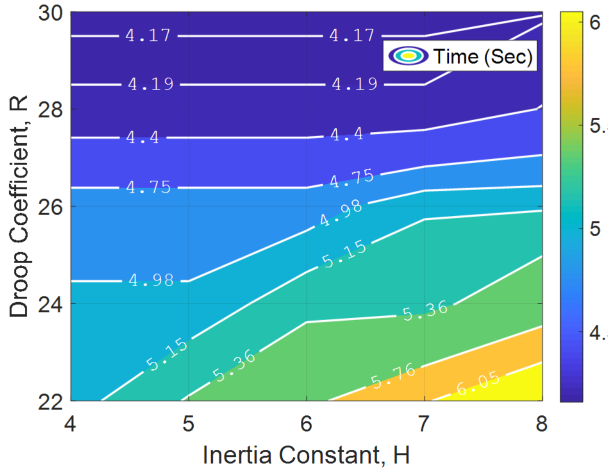


Fig. 10. Frequency Settling-time for different values of droop coefficient of BES-inverter and inertia constant of SG.

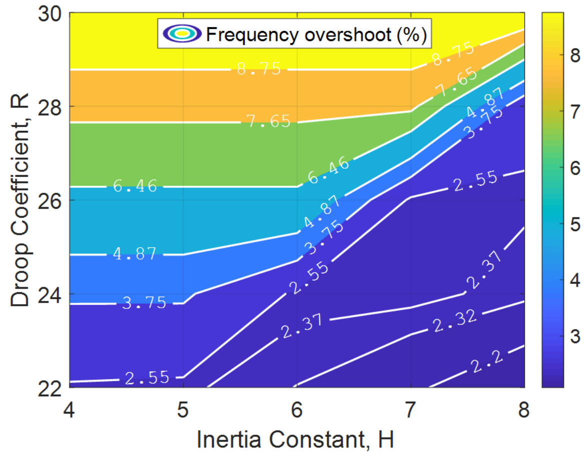


Fig. 11. Frequency-overshoot for different values of droop coefficient of BES-inverter and inertia constant of SG.

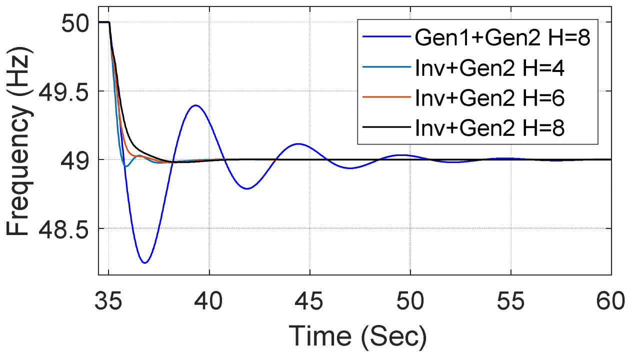


Fig. 12. Frequency response of the system with two SGs of Gen1 with primary control functionality and Gen2, then frequency response of the system with an SG of Gen2 varying inertia constant and an inverter equipped with primary control functionality.

and non-synchronous generation units on the primary BES-inverter is rapidly able to arrest declining ROCOF that results in low-ROCOF and quicker frequency settling. Furthermore, the frequency oscillation and the settling-time during the primary frequency control are greatly reduced.

The simulation results prove that the BES is capable of providing better primary frequency control services, both decreasing the frequency oscillations and the settling-time compared to the conventional generating unit.

V. Conclusion

The performance of primary frequency control using BES has been investigated at a different typical type of synchronous and the non-synchronous generating units. BES can play a key role in providing primary frequency control in a power system with low-inertia. The BES is able to rapidly inject active power into the system when an increased step-load occurs, thus arresting system frequency decline and stabilising frequency more rapidly than a conventional generator is able to. Despite, the droop coefficient has less influence on ROCOF, the ROCOF is improved as BES-inverter is rapidly able to arrest declining ROCOF after the contingency event occurs. This results in low-ROCOF and quicker frequency settling. Moreover, the inertia has less impact on the frequency settling-time when BES provides primary frequency response. Therefore, droop coefficient of BES-inverter has a significant impact on frequency overshoot since high droop coefficient provides a more aggressive frequency response in the system.

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