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Security Assessment of System Frequency Response

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***Abstract*— Low inertia power systems experience more extreme frequency dynamics immediately after a disturbance. A higher rate of change of frequency (ROCOF) contributes to a lower frequency nadir which could trigger load shedding schemes. Active power injections in a time frame of two seconds or less are necessary to maintain frequency stability. This paper develops an analysis of the closed-loop transfer function of a single-area power system model for frequency response (FR). This model is useful to study the frequency dynamics following a sudden load imbalance in a highly meshed system in which all the generating units are combined into a single equivalent unit with an aggregated inertia constant. The dynamics of the turbine and speed governor are included as first-order lag functions in the Laplace domain. A numeric example of the impact of system inertia and frequency controllers in the UK power system is then developed in MATLAB, and minimum values for Primary and Fast Frequency Response (FFR) power injections are calculated.**

***Index Terms*— System Frequency Response, Minimum Inertia, Primary Frequency Response, Fast Frequency Response.**

I. Introduction

Traditional control of system frequency involves initially relying on the inertia of the rotating generating units to slow down a frequency change. An automatic adjustment in the active power of the generators in response to the frequency change, known as Primary Frequency Response (PFR) then follows the inertial response. In large, highly meshed grids such as the Continental European power system (ENTSO-E), the levels of inertia are such that the rate of change of frequency (ROCOF) following a disturbance rarely exceeds ±0.1 Hz/s [1].

On the other hand, in power systems with low levels of inertia, the frequency decline following a disturbance (e.g. a sudden loss of generation) is of such magnitude that traditional frequency control measures such as PFR begin to lose effectiveness. In these cases, the ROCOF is large enough that there is a risk that a sizeable number of distributed generation (DG) disconnects due to the operation of loss of mains (LOM) protections and causes a cascade frequency drop. The operative range in the GB power system is ±0.2 Hz, and the statutory range is ±0.5 Hz [2], [3]. At ROCOF levels of 0.3 – 0.5 Hz/s there is approximately one second for the combined PFR to halt the frequency drop and to keep it inside the statutory levels. In the synchronously isolated system of Ireland, it is mandatory for generating units to remain connected to the grid for disturbances causing a ROCOF of up to ±0.5 Hz/s [4]. This limit will increase to ±1 Hz/s, measured over a sliding window of 500 ms, once the system operator EirGrid guarantees that enough generating units can comply with the new requirement and remain synchronised. A more extreme situation is experienced by the Australian Energy Market Operator (AEMO) in which events causing a ROCOF in the range of 1 – 2 Hz/s could arise and considering that a ROCOF in excess of 4 Hz/s has been recorded recently [5]. Since the typical response from synchronous governors is around 5 to 10 seconds, a faster frequency response service is necessary.

Fast Frequency Response (FFR), which is sometimes referred to as synthetic inertia [6], denotes an exchange of active power between non-synchronous generating units and the grid in a time frame of two seconds or less, with the purpose to assist in maintaining the frequency in low inertia power systems [5]. The very high response rate (tens of milliseconds) of the asset delivering the active power has the effect of partially emulating the inertia provided by rotating generators and therefore reducing the ROCOF following a disturbance. Unlike system inertia, which is instantaneous, FFR has an associated measurement and response delay. Devices could provide this service with response times between 10 – 20 ms [5]. A component of the FFR suite of services is the so-called Fast Frequency Control (FFC). This service comprises a fast injection of active power with a typical response time of less than a second and a narrow deadband (smaller than ±0.05 Hz). Enhanced Frequency Response (EFR) constitutes an example of FFC put in place by the GB Electricity System Operator (NGESO) which is targeted mainly at Battery Energy Storage Systems (BESS) [7], [8]. Another mechanism for the provision of FFR services consists on the tracking of the ROCOF instead of the frequency deviation, and it is usually termed Synthetic Inertia Control (SIC) [9]. This type of control is based on a simplification of the dynamics of a synchronous generator (SG) as it neglects all but the electromechanical interactions by employing the swing equation. SIC is employed in all wind farms of the Hydro-Quebec power system where it essentially tries to emulate the behaviour of a synchronous machine by extracting energy from the drive train of the wind turbine and delivering active power proportionally to the ROCOF [5].

The purpose of this document is to obtain the minimum values of PFR and FFR necessary in the GB system to contain the frequency nadir inside the statutory and operative range for different conditions of system inertia and for disturbances of

different magnitudes. Additionally, the initial ROCOF immediately after the disturbance is obtained for different values of the expected system inertia. A systematic review of the different response measures undertaken to control the frequency is performed considering the nonlinearities that arise from the inclusion of measurement time delays and deadband.

II. Frequency Response

A. Inertial Response

The frequency of the power system is a measure of the instantaneous balance between generation and demand. The synchronous generators present in the system will inherently absorb load fluctuations by changing their rotational speed. The larger the inertia constant of the machine, the less change in speed is necessary to release (or absorb) the required amount of energy. Consequently, an excess generation will cause a frequency increase, raising the kinetic energy of the machine, while a generation deficit will cause the frequency to drop as kinetic energy is released. Considering small deviations of the system frequency from the nominal value, the linearized equation of motion, known as swing equation can be written as:

$$\frac{d\Delta f}{dt} = \frac{f_0}{2HS_B} \cdot \Delta P \tag{1}$$

Here, the term Δf represents a small deviation of the system's frequency with respect to the nominal frequency f_0, H is the aggregated inertia constant of the grid's generators, S_B is the combined rated power of the generators and $\Delta P = \Delta P_{mec} - \Delta P_{load}$ is the difference between the changes in mechanical power and system load or accelerating power. Transforming (1) to the Laplace domain gives the following transfer function between a change in accelerating power and the variation in the system's frequency.

$$G_{Sys}(s) = \frac{f_0}{2HS_B s} \tag{2}$$

With no control system in place, a disturbance in the net system load will cause the system's frequency to deviate, following a slope which is inversely proportional to the system's inertia, and to stabilise in a value different from the nominal once the disturbance is removed. To bring the frequency back to its nominal value, a control scheme needs to act in a coordinated way among the system's generating units to inject the deficit or subtract the excess of energy consequence of the disturbance.

B. Primary Frequency Response and Fast Frequency Response

In the classical swing equation for an interconnected system, also called Aggregated Swing Equation (3), all the generating units are considered to be connected to the same bus which represents the grid's Centre of Inertia (CoI) [10].

$$\frac{d\Delta f}{dt} = \frac{f_0}{2HS_B}\left(-\left(k_D + k_{Prim} + k_{Fa}\right)\Delta f - k_{Vi}\frac{d\Delta f}{dt} + \Delta P\right) \tag{3}$$

The term k_D is the inverse of the often-used load damping coefficient D_{load} which represents the power demand of the frequency-dependent loads. The term k_{Prim} is the inverse of the equivalent generator droop coefficient R and it represents the traditional PFR to changes in the system frequency. Because the generators providing this service need time to ramp up and increase their power output, this service is usually activated within 5 to 10 seconds after the frequency deviation is measured [6]. In the UK, PFR needs to be fully enabled, as a maximum, at least 30 seconds after the frequency deviation is measured [3]. The term k_{Fa} represents a fast-active power injection to the system according to the FFC method explained before. It should be fully active within 5 seconds of the disturbance [10] and therefore can be delivered by several types of Energy Storage Systems (ESS), notably Battery Energy Storage System (BESS) or clusters of Electric Vehicles (EV) charging in Vehicle-to-grid (V2G) enabled facilities. Finally, the term k_{Vi} represents the SIC contribution of active power which is proportional to the ROCOF of the system.

To obtain the basic shape of the response, it is possible to use linearised models that do not consider the time dependence of the PFR and FFR coefficients. Consequently, (3) becomes a first order, linear differential equation with constant coefficients which can be solved analytically to obtain:

$$\Delta f(t) = \frac{\Delta P}{k_D + k_{Prim} + k_{Fa}}\left(1 - e^{\frac{-\left(k_D + k_{Prim} + k_{Fa}\right) f_0 t}{2HS_B + k_{Vi} f_0}}\right) \tag{4}$$

$$ROCOF = \frac{d\Delta f(t)}{dt} = \frac{\Delta P \cdot f_0}{2HS_B + k_{Vi} f_0} \cdot e^{\frac{-\left(k_D + k_{Prim} + k_{Fa}\right) f_0 t}{2HS_B + k_{Vi} f_0}} \tag{5}$$

From (4), the frequency responsive terms k_D, k_{Prim} and k_{Fa} have a strong influence in the steady-state of the frequency as well as on the subsequent ROCOF after the disturbance. It can be observed from (5) that the initial ROCOF, immediately after the disturbance, is directly proportional to the magnitude of the disturbance and inversely proportional to the aggregated system's inertia constant, H. The effect of the SIC coefficient k_{Vi}, is equivalent to an increase in the system's kinetic energy and therefore it has the effect of reducing the initial ROCOF. This equation suggests that to contain the frequency nadir to a specified value, it results more efficient to implement an FFC scheme rather than a SIC scheme. However, the effect of the frequency responsive terms on the frequency nadir is more complex as both the derivative and the proportional controllers influence the minimum frequency deviation.

C. Inclusion of Turbine and Speed Governor Dynamics

The turbine and governor dynamics curb the capability of the primary frequency response services mainly due to time delays and ramping rate limitations. To consider the dynamics of the equivalent turbine and speed governor, its useful to transform (3) to the Laplace domain considering zero initial conditions (the system is operating at rated frequency before the disturbance). The generic block diagram is shown in Figure 1.

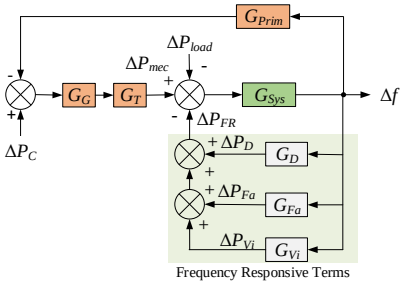


Figure 1. Block diagram including Frequency Responsive terms.

The frequency responsive terms are divided into two groups. The first group models the variation in system demand following a frequency change and it is represented by the transfer function G_D.

$$G_D(s) = k_D \tag{6}$$

The second group corresponds to the output power from FFR enabled non-synchronous generating units that provide both FFC (G_{Fa}) and SIC (G_{Vi}) and is defined as follows:

$$G_{Fa}(s) = k_{Fa} \tag{7}$$

$$G_{Vi}(s) = s \cdot k_{Vi} \tag{8}$$

The remaining transfer functions in Figure 1 are defined below:

$$G_{Prim}(s) = k_{Prim} = \frac{1}{R} \tag{9}$$

$$G_G(s) = \frac{K_G}{1 + sT_G} \tag{10}$$

$$G_T(s) = \frac{K_T}{1 + sT_T} \tag{11}$$

It is possible to combine the frequency responsive terms G_D, G_{Fa} and G_{Vi} into an equivalent transfer function G_{FR} which is the sum of the previous terms. Furthermore, it is possible to eliminate the feedback loop of the frequency responsive terms by combining it with the system's transfer function, arriving at the block diagram presented in Figure 2 .

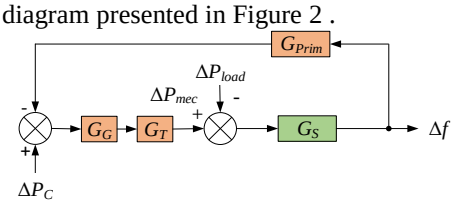


Figure 2. Reduced block diagram for frequency response.

At this stage, it is convenient to apply the superposition principle to obtain the system response for changes in the turbine power reference ΔP_C and changes in the net power demand ΔP_{load} (12). To obtain the transfer function G_{PL}, the power reference is set to zero in Figure 2 and after some simplification, it is possible to arrive at (13).

$$\Delta f = G_{PC} \cdot \Delta P_C + G_{PL} \cdot \Delta P_{load} \tag{12}$$

$$G_{PL} = -\frac{G_S}{1 + k_{Prim} \cdot G_S G_G G_T} \tag{13}$$

Substituting (6) – (11) in (12) – (13) it is possible to arrive at the following expression for the frequency deviation in the Laplace domain (14).

$$\Delta f(s) = \frac{K_G K_T f_0 \Delta P_C}{2HS_B s(1+sT_G)(1+sT_T)\sigma_1\sigma_2} - \frac{f_0 \Delta P_{load}}{2HS_B s \cdot \sigma_1\sigma_2} \tag{14}$$

where:

$$\sigma_1 = \frac{K_G K_T f_0 k_{Prim}}{2HS_B s(1+sT_G)(1+sT_T)\sigma_2} + 1 \tag{15}$$

$$\sigma_2 = \frac{f_0}{2HS_B s}(k_D + k_{Fa} + k_{Vi} s) + 1 \tag{16}$$

To observe the behaviour of the system's frequency following a load disturbance, the power reference to the turbine is set to zero in (14) resulting in the closed-loop transfer function (17).

$$\Delta f(s) = -\frac{f_0}{2HS_B \cdot s \cdot \sigma_1\sigma_2} \Delta P_{load} \tag{17}$$

Equation (17) will be applied in the following sections to obtain the minimum PFR and FFR necessary to contain the frequency to the values specified in the SQSS following a disturbance for different system inertia conditions.

III. Methodology

A. General Overview

To operate a stable system, the frequency nadir, ROCOF and the steady-state value of the frequency following a disturbance must be constrained [11]. To determine the initial ROCOF as well as the minimum requirements for PFR and FFR, the system equations defined in Section II were implemented and solved using MATLAB. The values of PFR and FFR obtained are the minimum necessary to limit the frequency nadir after a disturbance to the statutory and operative limits stipulated in the SQSS [3].

B. Initial ROCOF

To obtain the initial ROCOF (5) was solved with $t = 0$. The process was repeated with different values for the independent variables H and ΔP according to the flowchart depicted in Figure 3. The independent variables were initialised with an inertia constant equal to H_0 = 70 GVA.s, corresponding to the minimum expected value in the UK system for the year 2025 [6] and with a net load disturbance corresponding to a loss of $\Delta P^{\text{scheduled}}$ = 1,200 MW. The maximum value considered for H was 300 GVA.s corresponding to the highest expected value for the year 2025 [6] and the maximum ΔP considered was 1,800 MW [3].

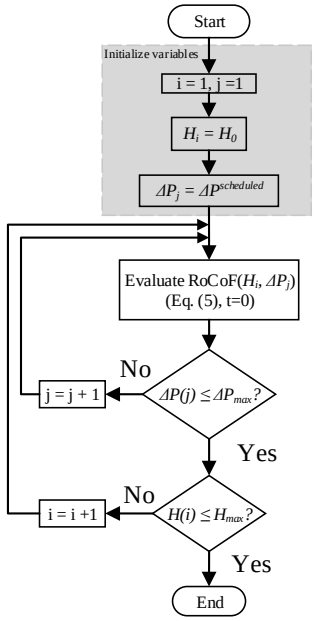


Figure 3. Flowchart for determination of the initial ROCOF following a net load imbalance.

C. Minimum Requirements for Primary Frequency Response

A stepwise change in the net power demand ΔP_{load}, was simulated and applied to the dynamic power system model defined by (17). Subsequently, the step-response characteristics (peak and peak time) of the dynamic system model were computed. Measurement and delivery delays in the provision of PFR were considered as their detrimental effects on the system performance could cause instability [10]. To model the effects of the time delay, a block consisting of the exponential function $e^{-s\tau_{PFR}}$, where τ_{PFR} represents the delay in the delivery of PFR (see Figure 5), was included in the dynamic power system model. Four scenarios were created to investigate the impact of the time delay in the PFR requirements. The process followed, and the details of each scenario are depicted in Figure 4. The values of H, ΔP and k_{Prim} were initialized at 70 GVA.s, 1,300 MW and 0 MW/Hz respectively. The load damping coefficient was assumed constant for these scenarios and equal to 2.5 % as per [6].

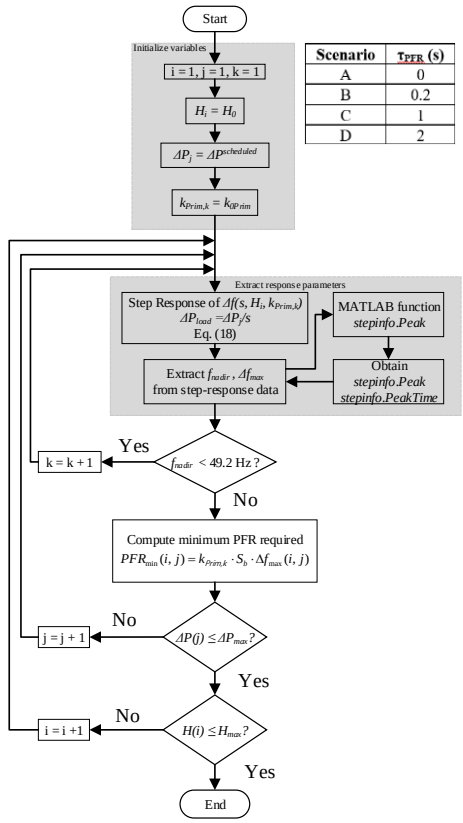


Figure 4. Flowchart for determination of the minimum value of PFR following a net load imbalance.

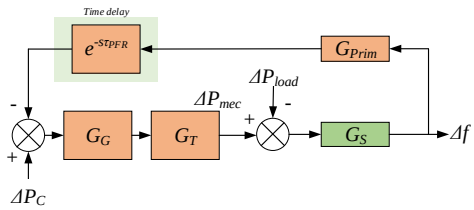


Figure 5. Reduced block diagram for frequency response including time delay in the PFR.

D. Minimum Requirements for FFC and SIC

The minimum FFC power injection necessary to contain the frequency following a disturbance to within NGESO statutory (±0.5 Hz) and operative (±0.2 Hz) limits was quantified. Different scenarios were studied, and the effects of the measurement delay and control deadband were observed (see Table I). The PFR supplied by the synchronous generation was set to limit the maximum instantaneous frequency deviation to 0.8 Hz [2]. The governor and turbine dynamic parameters, as well as the load damping coefficient, were kept as in Section III.C and a measurement delay in the provision of PFR (τ_{PFR}) equal to 2 s was considered.

Table I. Simulation scenarios considered for FFC coefficients.

Scenario	τ_{PFR} (s)	τ_{Fa} (s)	Deadband (Hz)
A	2	0	0
B	2	0.5	0
C	2	0.5	0.05

IV. Simulations, Results and Discussion

A. Initial ROCOF

The simulation results presented in Figure 6 show the magnitude of the initial ROCOF after the disturbance for different values of *H*. The initial ROCOF exceeds the embedded generator protection relay limit of 0.125 Hz/s in most scenarios. In fact, the ROCOF is larger than the limit for 90.5% of the considered scenarios as shown in Table II. As discussed in Section II, a suitable measure for improving the initial ROCOF consists of including a SIC in which the output is proportional to the ROCOF. The effect of the SIC is to diminish the initial ROCOF and therefore is analogous to increasing the inertia of the system. Table II shows the percentage of times that the initial ROCOF is larger than a specified value for different values of k_{Vi}. The magnitude of the maximum initial ROCOF in the case of no SIC corresponds to 0.6429 Hz/s whereas if a controller with a SIC coefficient of k_{Vi} = 3 GJ/Hz is included, the value reduces to 0.3103 Hz/s.

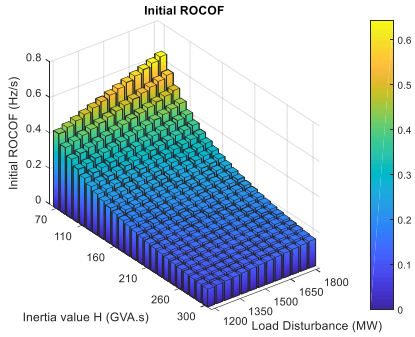


Figure 6. Initial magnitude of ROCOF under different system inertia conditions for k_{Vi} = 0.

Table II. Percentage of times exceeding the specified ROCOF for different values of k_{Vi}.

ROCOF value (Hz/s)	k_{Vi} = 0	k_{Vi} = 1.5 GJ/Hz	k_{Vi} = 3 GJ/Hz
0.125	90.5%	82.1%	66.7%
0.3	24.4%	9.5%	0.6%
0.5	3.6%	0.0%	0.0%
1	0.0%	0.0%	0.0%

Next, we solve (5) for k_{Vi} to obtain the minimum value that would guarantee an initial ROCOF equal to or lower than a certain limit and obtain (18).

$$k_{Vi} = \frac{1}{f_0}\left(\frac{\Delta P \cdot f_0}{ROCOF_{lim}} - 2HS_B\right) \tag{18}$$

Figure 7 shows the SIC requirements to contain the initial ROCOF after a loss of generation event of 1,800 MW for different inertia constants. In a system with an inertia constant *H* equal to 70 GVA.s, to guarantee an initial ROCOF equal or lower than 0.125 Hz/s, it is necessary a virtual inertia controller with k_{Vi} equal to 11.58 GJ/Hz. If the initial ROCOF limit is relaxed to 0.3 Hz/s, then a smaller k_{Vi} of 3.2 GJ/Hz is necessary.

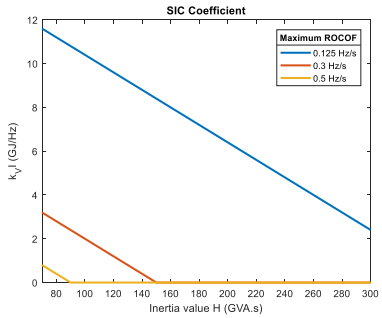
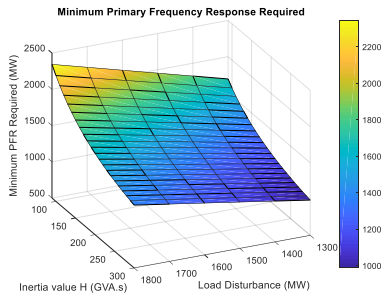


Figure 7. SIC requirements to guarantee different ROCOF limits.

B. Minimum PFR

Figure 8 (a) shows the PFR required to contain the maximum instantaneous frequency deviation to 0.8 Hz after a loss of generation and with a time delay of τ_{PFR} = 2 s. The response required increases with the size of the generation loss. It is also evidenced that as inertia decreases, more PFR is required. The minimum PFR requirements are summarised in Table III for different values of inertia constant and time delays and considering a disturbance equal to the UK reference incident. Without considering time delays, the required power injection for a given load disturbance is fairly constant and increases slightly as the system's inertia is reduced. By including time delays, the effect of the reduction in the system inertia becomes more pronounced as shown in Figure 8 (b).

(a)



(b)

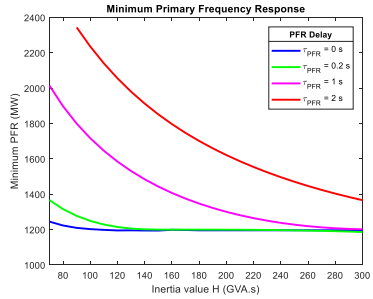


Figure 8.(a) Minimum Primary Frequency Response to contain frequency to 49.2 Hz for τ_{PFR} = 2 s. (b) Minimum PFR as a function of system inertia for different values of τ_{PFR}.

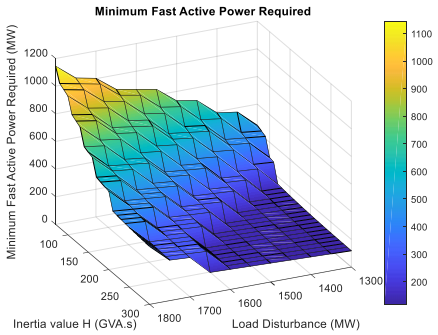
Table III. Minimum PFR required to contain the frequency to 49.2 Hz for different PFR time delays.

Inertia (GVA.s)	τ_{PFR} = 0 s	τ_{PFR} = 1 s	τ_{PFR} = 2 s
90	1,210 MW	1,800 MW	2,344 MW
160	1,199 MW	1,407 MW	1,797 MW
200	1,196 MW	1,301 MW	1,622 MW

C. Minimum FFC

Figure 9 (a) shows the minimum FFC active power injection necessary for different values of ΔP and H. The minimum inertia value necessary to guarantee the effectiveness of the FFC is affected by the measurement delays and deadband. Figure 9 (b) shows the minimum required FFC power injection to contain the frequency to statutory and operative limits following the reference incident. The effect of the measurement delay and deadband is to increase the minimum required level of FFC. To contain the frequency within the statutory limits a minimum of 993 MW is required without considering measurement delays and deadband in the FFC. If a measurement delay of 0.5 s is included, the required active power rises to 1,144 MW, and when the effects of a frequency deadband of 50 mHz are included, the requirement increases further to 1,313 MW. The statutory limits constitute a somewhat relaxed boundary, and therefore the power requirements remain fairly linear as the system's inertia changes even with the inclusion of time delays and deadbands. However, if the frequency is to be contained to the more stringent operative limits, the nonlinearities of the system become prevalent. For instance, when the inertia constant is equal to 140 GVA.s, the minimum required fast active power injection to contain the frequency deviation within the operative limits is 1,461 MW without considering measurement delays and rises to 2,697 MW when a delay of 0.5 s is considered.

(a)



(b)

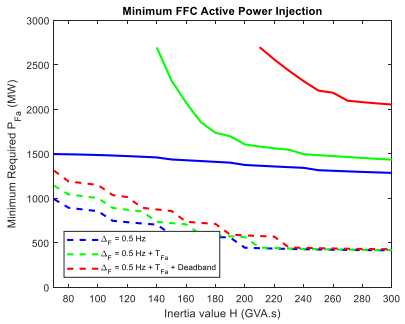


Figure 9. (a) FFC active power required to contain the frequency to statutory limits, τ_{Fa} = 0.5s. (b) Minimum FFC active power injection. Dashed line corresponds to the statutory limit (±0.5 Hz) and solid lines to the operative limit (±0.2 Hz).

D. Minimum SIC

Figure 10 shows the minimum SIC required to contain the frequency within the statutory limits. For H = 220 GVA.s and ΔP = 1800 MW, the necessary power from SIC rises to more than 6,000 MW whereas using FFC (see Figure 9 (b)), the power requirement is around 571 MW considering measurement delays and deadband.

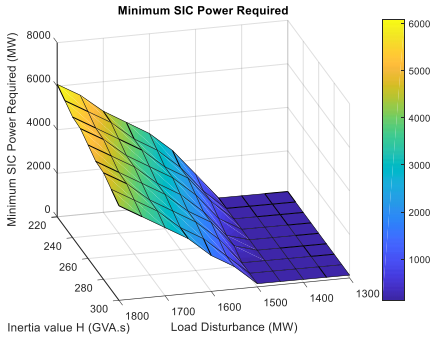


Figure 10. Minimum SIC power required to contain the frequency within statutory limits.

V. Conclusions

The purpose of the current study was to determine the minimum values of PFR and FFR that are necessary to keep the frequency inside the GB statutory and operative limits for different values of aggregated system inertia and disturbances of different magnitudes. Our results suggest that a limit of 1 Hz/s is suitable to minimise spurious trips of the LOM protection relays of DG units. The effect of the lag or time delay between frequency measurement and power delivery was included. This has the outcome of increasing the PFR required to comply with the minimum quality requirements. The effect of the SIC is more pronounced on the ROCOF while the FFC has a better performance controlling the frequency steady-state and nadir. In a practical system, the combined actions of the FFC and SIC form a very robust mechanism for the power system operator to deal with the inherent grid uncertainties.

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