

# DAMPING OF SUBSYNCHRONOUS RESONANCE USING A VSC-HVDC LINK

Luke Livermore   Carlos E. Ugalde-Loo   Jun Liang   Janaka B. Ekanayake   Nicholas Jenkins  
Cardiff University  
Cardiff, Wales, U.K.

LivermoreLB@cardiff.ac.uk, Ugalde-LooC@cardiff.ac.uk, LiangJ1@cardiff.ac.uk, EkanayakeJ@cardiff.ac.uk, JenkinsN6@cardiff.ac.uk

**Abstract** – A possible detrimental effect of onshore series compensation in the GB grid is the appearance of subsynchronous resonance (SSR). In this paper, a control scheme for a VSC-HVDC link capable of damping subsynchronous oscillations is proposed in order to effectively counteract the potential damage caused by SSR in steam turbines. The VSC-HVDC link has been modelled to maintain its primary functions of bulk power transmission and reactive power compensation and additional positive damping upon SSR occurrence.

**Keywords:** HVDC-VSC link, series compensation, subsynchronous resonance.

## 1 INTRODUCTION

Increased wind penetration in the north of Scotland will bring key operational challenges for the GB network. In its 2020 Vision, the Electricity Networks Strategy Group (ENSG) has proposed both onshore and offshore infrastructure reinforcements, as shown in Figure 1 [1]. This is since the transmission corridor between England and Scotland will not be adequate for power transmission with such an increased penetration.



**Figure 1:** Proposed network reinforcements for the 2020 Vision.

Onshore reinforcement will include series compensation in the form of fixed banks of capacitors, whereas two offshore HVDC links have been proposed –it is likely one of which will be a voltage source converter (VSC) based HVDC link [1].

### 1.1 Series Compensation

Series compensation is often cited as an efficient approach to increase the power transfer capacity of an AC network [2]. In addition, series compensation of lines can improve the voltage and angular stability of the system. The power transfer between two points in a system is described as

$$P = \frac{V_1 V_2}{X} \cdot \sin \delta \quad (1)$$

where  $P$  is power,  $V_1$  and  $V_2$  stand for the voltage at either end,  $X$  is the circuit reactance, and  $\delta$  is the angular difference between voltages  $V_1$  and  $V_2$ . By installing series compensation between two points within a system, the reactance between the line ends is reduced and the power transfer capability is increased.

Several technologies for series compensation have been proposed. The simplest involves the use of Fixed Capacitors (FC); however other more complex such as Thyristor-Controlled Series Capacitor (TCSC), Thyristor-Switched Series Capacitor (TSSC) and Thyristor-Protected Series Capacitor (TPSC) have been described [3]. In this study only the FC technology has been considered. The percentage of series compensation  $\kappa$  provided by FCs is given by:

$$\kappa = \frac{X_C}{X_L} = \frac{1/(\omega_R C)}{\omega_R L} = \frac{1}{\omega_R^2 CL} \quad (2)$$

where  $X_L$  is the inductive reactance of the transmission line and  $X_C$  is the compensating capacitive reactance of the FC. The size of the capacitor bank can be calculated as

$$C = (L\kappa\omega_R^2)^{-1} \quad (3)$$

### 1.2 Forecasted Offshore Wind Generation

The reinforcement of the transmission network is in part driven by the capacity and locations of renewable resources around the UK. These resources will fulfil the obligation of 15% of all energy in the UK to come from renewable sources by 2020 [4]. The prime candidate to supply this energy is wind power, particularly offshore where wind is stronger and more consistent. The construction of wind farms off the GB coast has been split into 3 rounds, with the larger and further offshore wind farms falling into round 3 [1]. Whereas round 1 and 2 sites are connected to the terrestrial grid through direct AC connections, it is expected that at least some of the round 3 sites will be connected through HVDC links.

### 1.3 Subsynchronous Resonance (SSR)

SSR is a dynamic phenomenon defined as an electric power system condition where the electric network exchanges energy with a turbogenerator at one or more of the natural frequencies of the combined system below the synchronous frequency [5]. The effects of SSR can be quite dramatic, as seen in the case of the Mohave generation station in 1970 [6]. Such a phenomenon prevails in series compensated networks [7].

Often within regional and national grids series capacitances are added to long AC transmission lines to reduce their inherent reactance. This intervention can often lead to SSR [5]. Since ENSG's suite of reinforcement measures include onshore series capacitance installations, the issue of SSR has become relevant again.

The threat of SSR is very real due to the change of the natural frequency of the electrical system by including series compensation. If appropriate measures are not taken, this electric frequency can interact with the natural mechanical frequencies of long shaft turbogenerators on the network. Undesirable subsynchronous oscillations may arise under such conditions, which ultimately will be reflected on stress, fatigue and damage to the turbine shaft and system performance [7].

The SSR concern has led to the approach of limiting the amount of series compensation in transmission lines to the order of 30-35% of system reactance [2]. A system may benefit from a higher level of compensation; however this is avoided as transmission system operators are concerned about the negative impacts of SSR.

### 1.4 The IEEE First Benchmark Model for SSR Studies

The IEEE First Benchmark Model was created by the IEEE Working Group on Subsynchronous Resonance in 1977 for use in computer program comparison and development [8]. This small system is described by realistic parameters and provides a useful test bed for SSR analytical methods. For instance, in [5, 7] the system is assessed using eigenvalue analysis.

The test system is shown in Figure 2. It comprises a turbogenerator that exports power to a bigger system through a series compensated transmission line. The compensation level is an adjustable parameter that can be modified in order to study SSR.

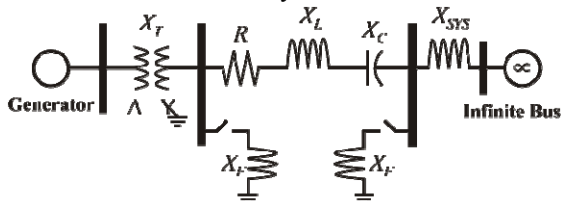


Figure 2: IEEE first benchmark model for SSR studies.

The parameters of the system are taken from the Navajo generation and transmission project [6, 8]. The Navajo turbogenerator, of 892 MVA, is coupled to a transmission network of 500 kV represented by a radial circuit connected to an infinite bus. The electrical parameters of the machine are expressed in p.u. on the generator base at 60 Hz. The reactances are proportional to the frequency and the resistances are constant.

## 2 THE GENERIC THREE MACHINE MODEL

A generic three machine network, shown in Figure 3, was designed to resemble the operating conditions of the mainland GB system [9]. Although a simplified case study of the national network, appropriate weighting of the size and type of generation is given. For the purposes of this paper, the model comprises three synchronous generators which split the network into three generation areas: England and Wales, Southern Scotland and Northern Scotland.

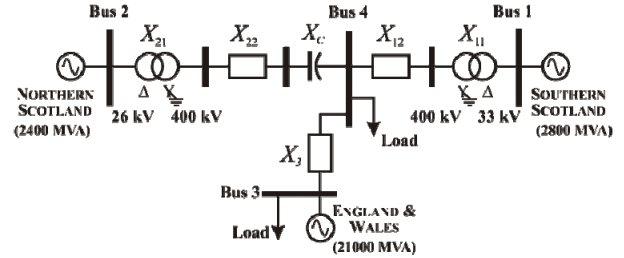


Figure 3: Generic network with series compensation.

The England and Wales generator is represented as the main system and is weighted in terms of capacity as such; the rating of this generator is 21,000 MVA. The Scottish generators are much smaller in magnitude: 2,800 and 2,400 MVA for Southern and Northern Scotland, respectively. Active power will generally flow from the Scottish generators to England and Wales. The machines' parameters are included in [10].

To assess SSR in this model, a number of adjustments have been considered to simulate the planned series compensation within the AC transmission lines and a potential VSC-HVDC link, as shown in Figure 4. A series capacitor has been included between buses 2 and 4 to represent the fixed capacitor series compensation of transmission lines between England and Scotland required to increase transient stability and thermal capacity.

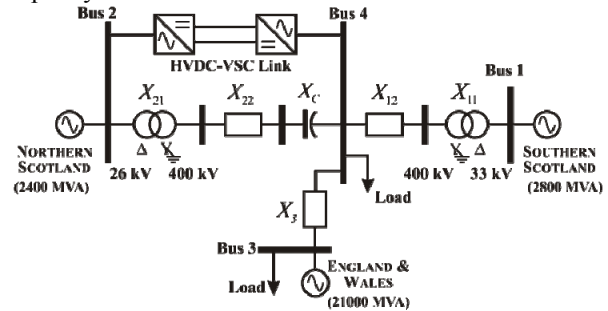


Figure 4: Three machine network with 2020 reinforcements.

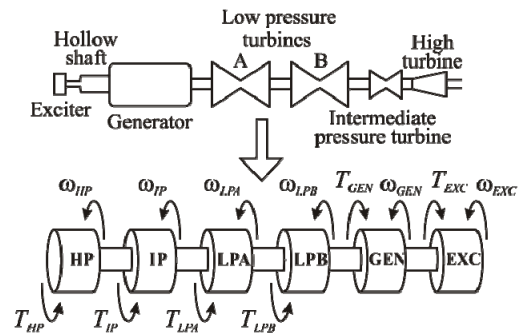


Figure 5: Northern Scotland generator shaft.

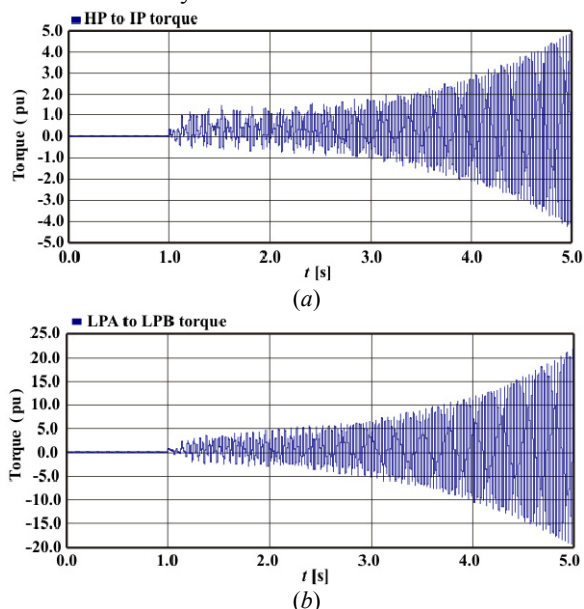
The Northern Scotland generator shaft has been modelled as a multi-mass system consisting of four turbine sections, the generator and exciter, as shown by Figure 5. The parameters of the shaft are as the ones used in the IEEE First Benchmark Model and can be found in [8]. The system frequency for the three machine network is 50 Hz, in agreement with the British scenario.

The specification of the generic network model gives reactances and resistances for the transmission lines and transformers – which can be found in [10]. These are incorporated into the simulation model by representing the transmission line reactance and series compensation as inductances and capacitances. When choosing the compensation percentage to be implemented this should be kept as low as possible to achieve the required transfer capability improvement. Initial studies imply that a level of 30-35% compensation would be appropriate [2].

### 3 SIMULATION RESULTS OF THE THREE MACHINE GENERIC NETWORK WITH SERIES COMPENSATION

In the initial simulation studies, only series compensation is considered. No consideration is given to either of the HVDC links. A series compensation of 35% is calculated for the transmission line connecting the Northern Scotland generator.

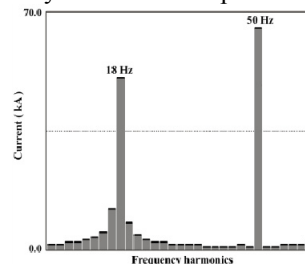
The series compensated network (Figure 3) was implemented on PSCAD/EMTDC. Figure 6(a) shows the torque between the high and intermediate pressure turbines, whereas Figure 6(b) illustrates the torque between the low pressure turbines at the Northern Scotland generator. The increasing torque amplitude after a three-phase fault (introduced at 1 s and released after 75 ms) shows that this system becomes unstable.



**Figure 6:** Torque interactions in the Northern Scotland generator shaft between (a) high and intermediate; and (b) low pressure turbines.

These results indicate that the three machine generic network with 35% compensation is susceptible to SSR. This can be furthered by examining the frequency spec-

trum of the Northern Scotland generator current, shown by Figure 7. As it can be seen, the current features an undesirable subsynchronous component at 18 Hz.



**Figure 7:** Frequency components (2 Hz interval) of Northern Scotland phase A current.

For completeness, the system state-space representation was also built. It comprises the differential equations of the synchronous generators [5], the electrical network, hydrogovernors [11] and exciters [12] for England-Wales and Southern Scotland generators and a multi-mass shaft with a mechanical hydraulic control governor and exciter [12] for the Northern Scotland generator. From a preliminary eigenvalue analysis, it is observed that one of the mechanical shaft modes of the Northern Scotland generator ( $\sim 30$  Hz) nearly coincides with the complement of a subsynchronous frequency component of the transmission network (around 18 Hz). Due to this condition, a disturbance is enough to trigger SSR, as shown by Figures 6 and 7.

### 4 SIMULATION RESULTS WITH SERIES COMPENSATION AND THE VSC-HVDC LINK

The onshore and offshore reinforcements of the transmission network between Scotland and England have been split as a compromise between the difficulty in building new onshore overhead lines and the risks of using technologies new to the transmission system. As discussed earlier, the offshore reinforcements will be two HVDC links between Scotland and England-Wales. The western link is planned to connect Hunterston in Scotland with Deeside in Wales at a rating of 1.8 GW. The eastern link will connect Peterhead in Scotland with Hawthorne Pit in England; planned capacity is not known yet [1]. It is reasonable to assume that at least one of these links would be a VSC link.

The primary design objective of a VSC-HVDC link between the north and south should be to ensure that active power control is achieved along with reactive power support for the grid. To accomplish this objective and the additional goal of damping SSR within the onshore grid, three control schemes have been designed.

#### 4.1 Primary Control

The primary scheme is designed to control reactive power, whilst offering control over the magnitude and direction of active power flow. Therefore the parameters to be controlled are active and reactive power at both terminals and the DC link voltage. This approach has been used previously in [13].

Figure 8 illustrates the control scheme when the converter is operating in primary control mode. PI controllers are designed using the  $d$ - $q$  reference frame. Control-

ler PI1 regulates the active power to a set point (in terminal A) or the DC voltage (in terminal B); moreover, it generates a reference current  $i_{qref}$ . PI2 performs this function at either end for the reactive power control and generates reference current  $i_{dref}$ . PI3 and PI4 regulate the  $dq$  currents, setting the appropriate converter control signals. A feedforward loop comprising the complementary voltage reference frame is included.

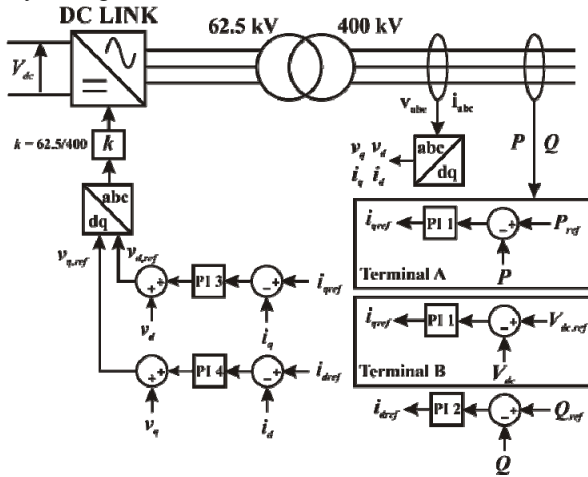


Figure 8: Primary control scheme.

In order to test this control scheme, the model of the network shown in Figure 4 was built in PSCAD. In the model the converters are modelled as 2-level PWM converters. The two generated voltages  $V_q$  and  $V_d$  are transformed to the three phase voltages for the PWM. Discrete gate drive signals for the six IGBT switches are generated to provide on and off signal states in the IGBTs. The two-terminal VSC-HVDC link joins the bus at the Northern Scotland generator with a central bus between the three generators. The VSC-HVDC runs parallel to the series compensated transmission line. Simulations have been carried out to ensure the system is stable and reaches the desired references after a step change, with results provided by Figures 9 and 10.

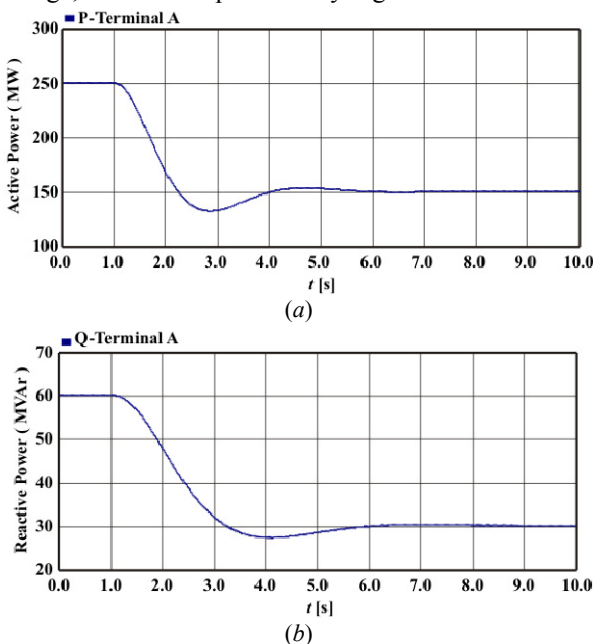


Figure 9: Terminal A: (a) active power; (b) reactive power.

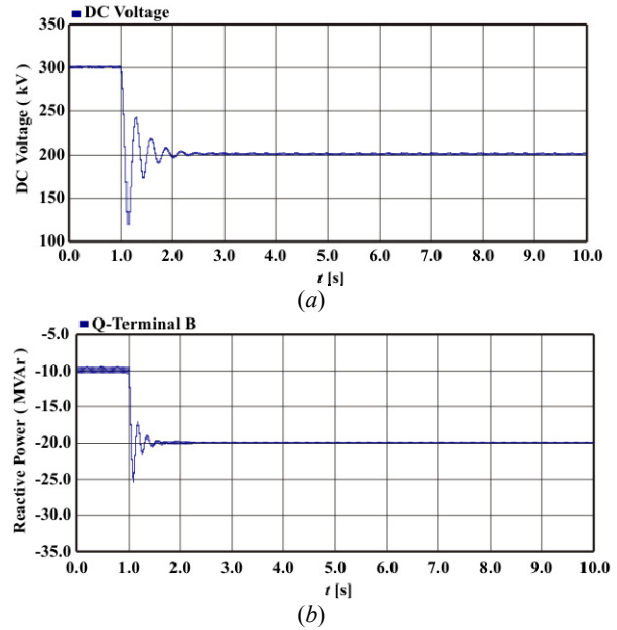


Figure 10: Terminal B: (a) DC voltage; (b) reactive power.

Initially, an active power set point of 250 MW has been used (shown in Figure 9(a)). A  $\pm 150$  kV DC voltage set point is employed (Figure 10(a)). Arbitrary reactive power set points of 60 MVar (absorption) at terminal A (Figure 9(b)) and 10 MVar (generation) at terminal B (Figure 10(b)) are used to verify the control scheme. In practice, these would be governed by the terrestrial grid operator. As it can be seen, the primary control exhibits an adequate performance.

However, it should be emphasised that SSR arises under fault conditions. To explore this issue a three-phase fault is simulated (of 75 ms, at 1 s). Figure 11 shows the torque interactions between turbine sections in the Northern Scotland generator shaft. Notice that the torque amplitude increases after the fault.

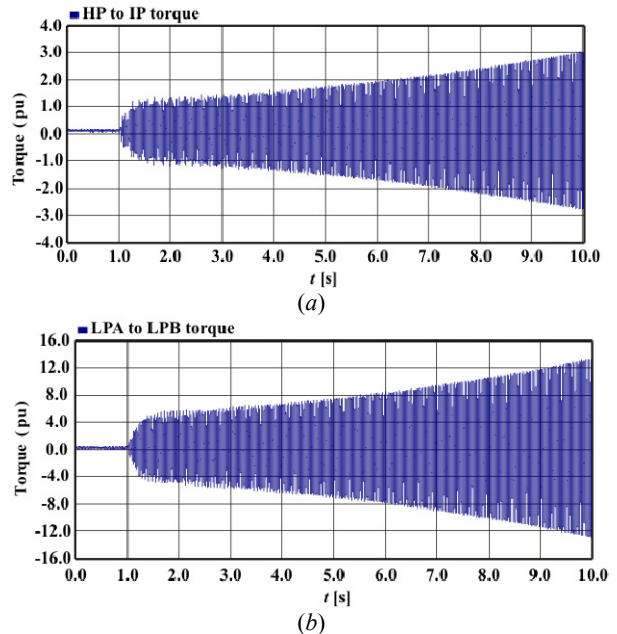
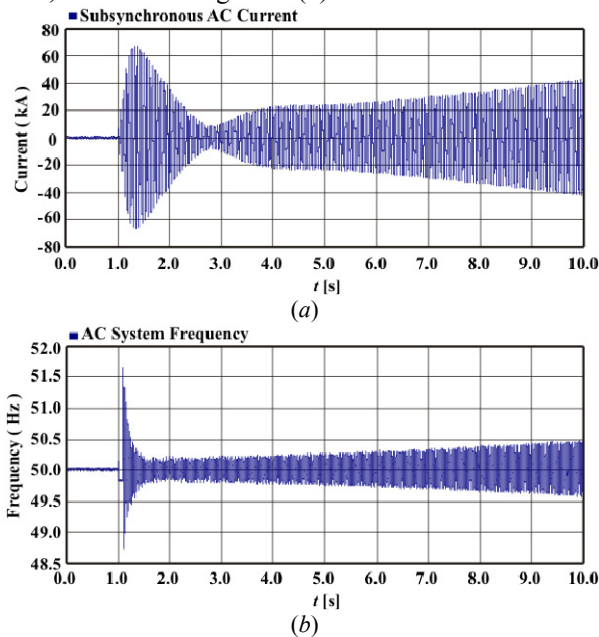


Figure 11: Torque interactions in the Northern Scotland generator shaft between (a) high and intermediate; and (b) low pressure turbines.

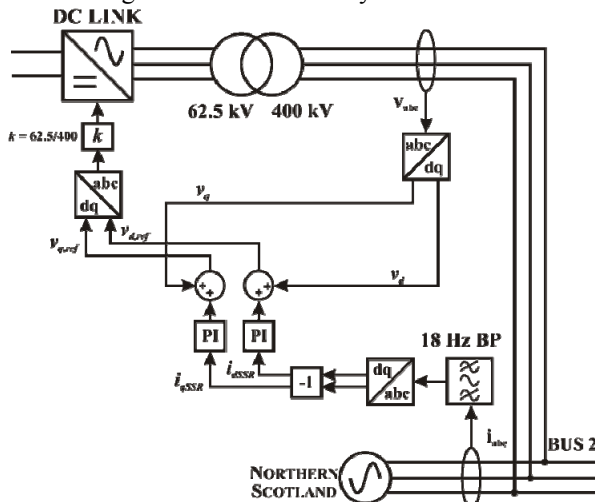
Figure 12(a) shows the Northern Scotland generator current. Its magnitude increases after the fault is released, featuring a subsynchronous component at 18 Hz. Equally, the AC system frequency shows such component, as shown in Figure 12(b).



**Figure 12:** (a) Northern Scotland generator phase A current; (b) frequency of the transmission line.

#### 4.2 Secondary Control

The secondary control scheme is designed to damp SSR in the AC system following a fault or disturbance. Under this control scheme the VSC at terminal A is designed to behave like an active power filter, injecting an anti-phase current into the AC system at a target subsynchronous frequency, which could potentially cause damage to the mechanical system.



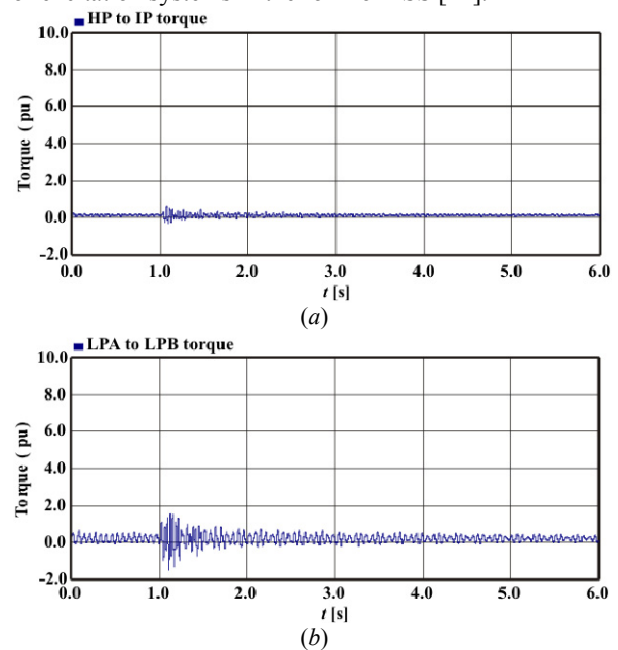
**Figure 13:** Secondary control scheme.

Figure 13 illustrates the control scheme when the converter is operating in secondary control mode. The controllers are designed using the  $d-q$  reference frame. The SSR created by the addition of series compensation and triggered by a three phase fault to ground is isolated. In this simulation this is done with a band pass filter set at 18 Hz, which is chosen from the eigenvalue

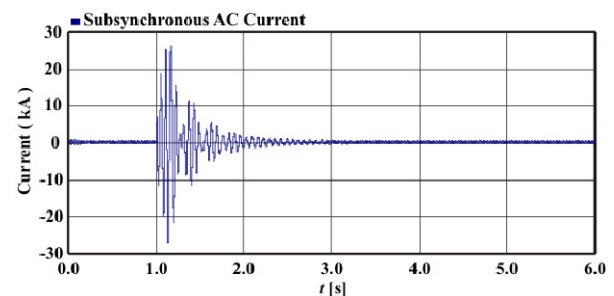
analysis of the system as described in Section 3. In general, the frequency can be identified using the estimation algorithm such as the one described in [14].

The complement of the filtered current signals is used as the reference, namely  $i_{dSSR}$  and  $i_{qSSR}$ . The PI controllers then regulate the VSC link voltages producing the  $dq$  control voltages sent to the converter.

Case studies were carried out to assess the performance of the secondary control scheme. A three-phase fault lasting 75 ms, at 1 s into the simulation, triggers SSR in the AC system. The secondary control is then able to damp it within 1.5 s as seen in Figures 14 and 15. The torque oscillations ( $\sim 1$  Hz) found in Figure 14 are due to local plant modes. The characteristics of these oscillations are well understood and adequate positive damping can be achieved by using supplementary control of excitation systems in the form of PSS [12].

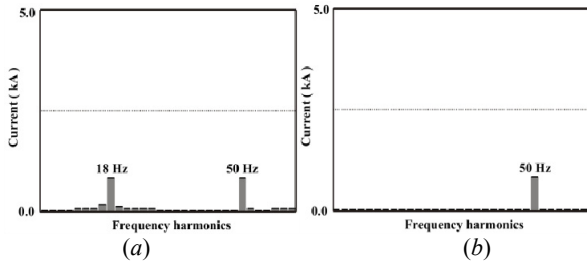


**Figure 14:** Torque interactions in the Northern Scotland generator shaft between (a) high and intermediate; and (b) low pressure turbines.



**Figure 15:** Northern Scotland generator current.

A comparison of the frequency spectrum of the Northern Scotland generator current in primary and secondary control modes is shown in Figure 16. It can be noticed that the secondary scheme eliminates the 18 Hz component without active and reactive power control during the damping process.

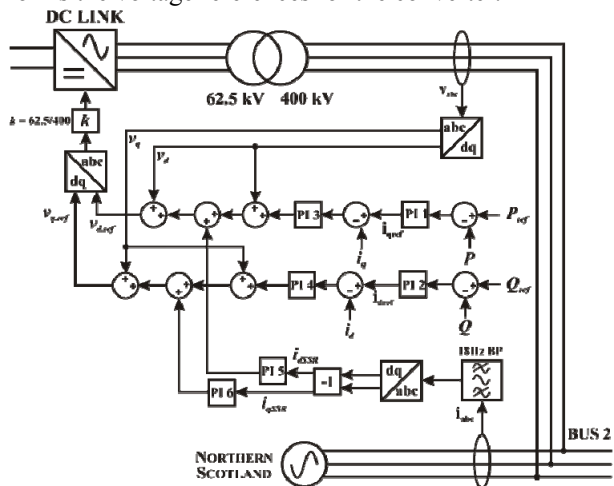


**Figure 16:** Frequency spectrum (2 Hz interval, 4.5 s after the fault): (a) primary control; (b) secondary control.

### 4.3 Hybrid Control

The hybrid control scheme is designed to perform the functions of the primary and the secondary control schemes simultaneously. Here, terminal B acts in the same fashion as before, setting the DC voltage and providing reactive power support to the grid. However terminal A provides SSR damping in addition to its primary functions of active and reactive power control.

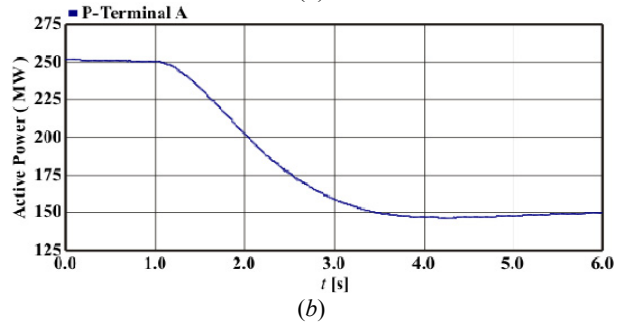
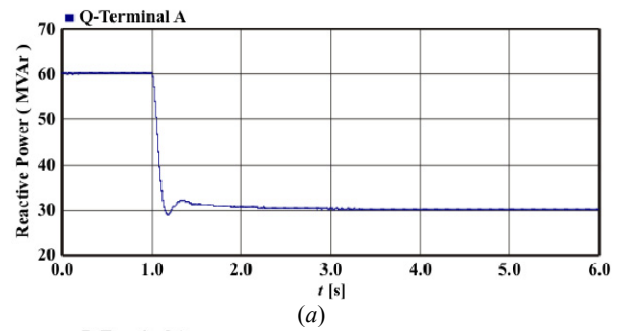
A schematic for the control scheme can be seen in Figure 17. The outer control loops provide active and reactive power control. The output of these loops sets the inner current controller references, which in turn produce a voltage output (as in the primary scheme). This voltage is fed forward with the SSR damping reference voltage as in the secondary scheme. The output forms the voltage references for the converter.



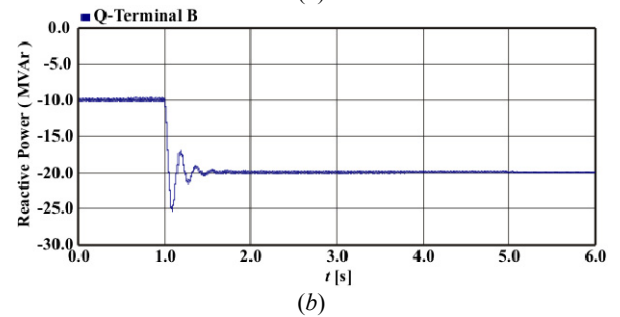
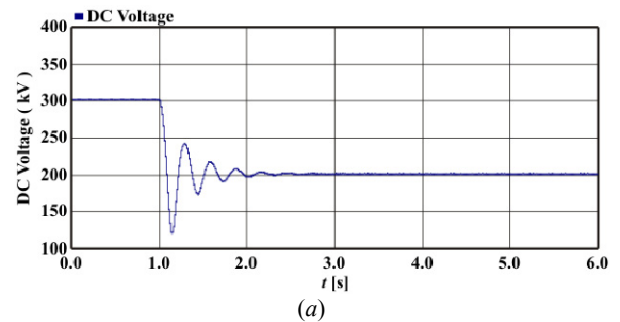
**Figure 17:** Hybrid control scheme.

Two simulations are carried out. The first one uses the same set points of Section 4.1 to test active and reactive power control. Figures 18 and 19 show that the hybrid scheme provides the control actions of the primary control. Moreover, a second simulation illustrates that it is also able to damp SSR following a fault in a similar fashion as the secondary control. This is shown by Figures 20–22, where a three-phase fault is simulated (at 1 s, released after 75 ms).

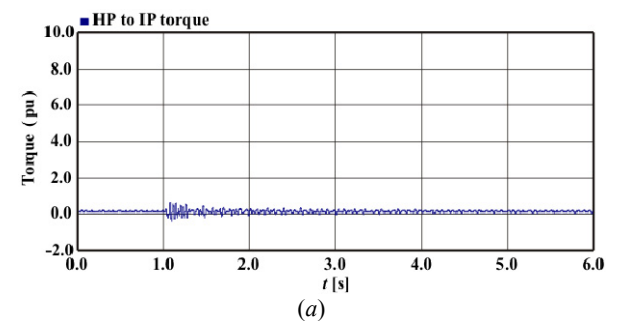
Figure 22 shows that the frequency spectrum of the Northern Scotland generator current (in Figure 21(a)) has no subsynchronous component. Similarly, the AC transmission line frequency remains at 50 Hz (Figure 21(b)). This can be confirmed by the lack of unstable torque interactions in Figure 20.



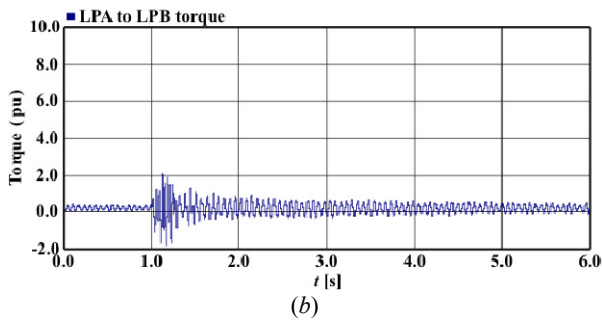
**Figure 18:** Terminal A in the hybrid control strategy: (a) reactive power; (b) active power.



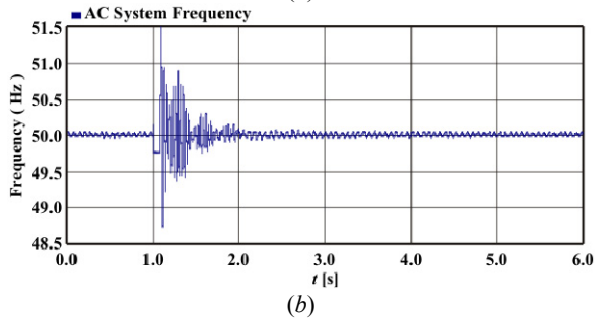
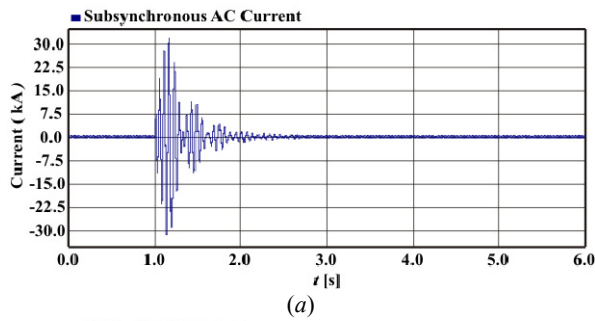
**Figure 19:** Terminal B in the hybrid control strategy: (a) DC voltage; (b) reactive power.



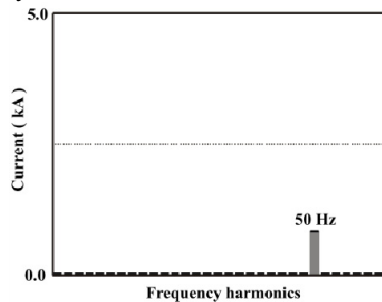
**Figure 20:** (a) Torque interactions in the Northern Scotland generator shaft between high and intermediate pressure turbines.



**Figure 20:** (b) Torque interactions in the Northern Scotland generator shaft between low pressure turbines.



**Figure 21:** (a) Northern Scotland generator phase A current; (b) frequency of the transmission line.



**Figure 22:** Frequency spectrum of the AC system under hybrid control.

## 5 CONCLUSION

The possible effects of reinforcing onshore terrestrial grids with series compensation have been presented. Particular emphasis has been given to the potential threat in the form of SSR that may arise under such conditions. A generic network model featuring an approximation to the GB grid in 2020 has been introduced and modified according to the planned onshore and offshore reinforcements.

Three control schemes have been examined and assessed. A primary control scheme has been designed in order to control active and reactive power. A secondary control scheme, aiming at the provision of SSR support,

has been proposed. A hybrid strategy combining the two previous control scenarios has been introduced. Simulation results show that the hybrid scheme is able to control active and reactive power and damp SSR simultaneously. Future work will consider the development of a frequency identification algorithm for the use in networks with different characteristics than those of the case studies of this paper.

## ACKNOWLEDGEMENTS

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