Techno-economic Evaluation of Power Electronics Assisted Transmission System Frequency Regulation

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Abstract

In many future power systems, the power generation may be predominantly supplied from converter interfaced sources (i.e. wind, solar, HVDC interconnection). In the context of the UK, the government is aiming for a share of wind capacity in the total generation mix as high as 29 GW by 2020. For a small power system like Great Britain (GB) with no synchronous connection to continental Europe, frequency stability is identified as a major challenge. Therefore, additional primary response and inertia (or fast frequency containment response) are anticipated as being required to sustain the frequency stability of the GB system. In this paper, techno-economic assessment is carried out to explore the overall benefits of various frequency control strategies. Frequency regulation by VSC-HVDC system is realized as the best strategy regarding overall system benefits.

1 Introduction

The concern regarding CO₂ emission reduction from the levels in 1990 and energy security has motivated the progress of the renewable energy industry in the UK. It is anticipated that high penetration of HVDC interconnections and offshore wind power plants (WPPs) connected through HVDC will be seen in the UK transmission system [1]. The proliferation of HVDC interconnections and offshore WPPs connected via HVDC will displace conventional synchronous generators in the Great Britain (GB) transmission system. Since the HVDC interconnection behaves as a firewall between the host AC system and WPPs, this will result in a drastic reduction of effective system inertia [2], [3]. Therefore, infed losses in a reduced inertia system will likely cause a large variation of frequency and high rate of change of frequency (RoCoF). Hence, additional fast primary response and inertia are needed to maintain the frequency stability of the GB system.

A number of different methods have already been proposed for primary frequency control in power systems. Energy storage, in particular, battery energy storage is proposed in [4]-[6]. In [7], the post-retirement utilization of synchronous generators as synchronous condensers is evaluated for frequency stability enhancement under high penetrations of wind in Australian power system. Moreover, many recent studies have proposed a VSC-HVDC system based frequency regulation controller (FRC) for frequency stability improvement in a mixed AC-DC system (which is the likely grid model for many power systems including the GB system) [8]-[11]. Most of the above-cited work tends to view the problem with an emphasis on a particular technology without any comprehensive comparison. It is not yet clear how much the overall technical benefits can be achieved within the system from all these methods. Furthermore, the implementation of frequency control with VSC-HVDC would reduce the size and rating of the battery energy storage and post-retirement generators for similar and nearly-similar frequency response performance in systems and, therefore, would reduce the associated cost. However, it is yet to be identified how much cost savings can be achieved by implementing various frequency control strategies in the system. Therefore, this work uses a holistic approach to compare the techno-economic performance of different frequency regulation methods in the representative GB transmission system.

2 Modelling overview

The model of a battery energy storage system (BESS), synchronous condenser, and dual-loop FRC for VSC-HVDC system including a mixed AC-DC test system are briefly illustrated in this section.

2.1 BESS model

The generic BESS model presented in [12] is used for this work. The BESS comprises a voltage converter, control, and battery model. In this configuration, the battery is modelled as a voltage source with internal impedance as stated in [13]. The voltage of the battery linearly varies with the state of charge (SOC) whereas the internal resistance of the battery is assumed to be constant. With these assumptions, the battery model can be expressed as (1).

\[ V_{\text{DC}} = V_{\text{max}} \cdot \text{SOC} + V_{\text{min}} \cdot (1 - \text{SOC}) - IZ_i \]  
\[ (1) \]

In (1), \( V_{\text{DC}} \) is the DC terminal voltage of the battery, \( I \) is the charge/discharge current, \( V_{\text{max}} \) and \( V_{\text{min}} \) are the maximum and minimum voltages of the cell, \( Z_i \) is the internal resistance of the battery, and \( SOC \) is the state of the charge of the battery. The BESS model utilized in this work supplies active power \( (P) \) to the network when the network experiences a frequency
drop and absorbs active power during frequency rises. The frequency controller of the BESS is given in Fig. 1 (a). The frequency control in BESS consists of droop control which defines the active power reference signal to the active power controller corresponding to frequency deviations measured at the point of common coupling (PCC) of BESS. The BESS has an AC voltage control mechanism as shown in Fig. 1 (b). It regulates the AC voltage at the PCC by adjusting the q-axis current reference signal.

Fig. 1: BESS controller: (a) Frequency droop control; (b) Active power and AC voltage control.

2.2 Synchronous condenser

The post-retirement utilization of a synchronous generator as a synchronous compensator is considered in this work [7], [14], and will henceforth be referred to as a synchronous condenser (SC) in the rest of the paper. The SC is considered here to be run without a prime mover [15]. Since there is no prime mover, it does not generate active power. However, it does act as a synchronous machine during normal and transient system conditions. An excitation system is required to control the field of the machine. A static excitation system (type ST1A) is used to control the reactive power generation and absorption in the system [15]. For this study, the SC is modelled using the 6th order model of the synchronous machine with static excitation system.

2.3 Dual-loop FRC of VSC-HVDC

In this work, the VSC-HVDC frequency control structure given in Fig. 2 has been investigated. The main concept is to build an additional VSC-HVDC frequency control on top of the state-of-the-art frequency control approach (in this case droop control) to provide virtual reserve through VSC-HVDC systems. The frequency control structure given in Fig. 2 provides governor-like droop behaviour through active power (P) or DC voltage loop, henceforth referred as droop at P loop. The virtual inertia is provided through the reactive power or AC voltage control loop of the VSC-HVDC system, henceforth referred as inertia at Q. Appropriate filters (i.e. low pass filter) and limiters are used in both loops to avoid the undesirable control operation. The further details about this controller can be found in [11].

The droop controller exploits the WPP active power to provide a frequency regulation service to the host AC system. Since the frequency droop control in the DC voltage controller changes the DC voltage of the entire link, utilization of this could potentially provide a means by which a decoupled WPP can be informed of the occurrence of the frequency event in the AC system. Frequency droop and a transient frequency adjustment as a function of DC link voltage are used to configure the offshore VSC system and enable it to contribute to the offshore grid frequency control with other converters.

Fig. 2: Dual-loop frequency controller.

2.4 Test system model

The AC system model given in Fig. 3 (a) is used in this study. The basis for this test system model is obtained from a representative GB network model published previously in [16]. The structure and parameters of the system given in Fig. 3 (a) are selected such that the network is an approximation of the England-Wales and Scotland power system. Despite its simplicity, this network is a reasonable representation of the overall dynamic behaviour of the UK system.

As given in the figure, the system consists of four representative synchronous generators and wind power plants (WPPs) in the England-Wales and Scotland power system. Similar to [16], South Scotland is represented by an aggregated generator of 2.8 GVA capacity. The North Scotland system includes an aggregated synchronous generator of 2.0 GVA and WPPs of 2 GVA, respectively. The grid representation of the England and Wales system includes two synchronous generators and two WPPs. One of the two synchronous generators representing England and Wales system is chosen to be large (17 GVA) whereas the other is 2.4 GVA. The rating of each WPP is 1 GVA. The load of the system is represented in an aggregated manner at bus 3 and 6. The dynamic simulation has been conducted in this paper using a polynomial load model (i.e. ZIP model). An aggregated round rotor synchronous generator is considered to represent each conventional generator of the system. All these generators are equipped with a DC1A excitation system and steam governor.

The offshore AC system (see Fig. 3 (b)) is developed to represent the offshore WPPs and their associated interconnections. The system consists of eight aggregated full converter wind turbines with a total capacity of 1.5 GVA. The wind turbines are integrated to the onshore AC system at bus 6
by two parallel VSC-HVDC links. Each converter terminal in the system is rated at 1000 MW, ± 320 kV with the DC capacitor of 150 µF. The two VSC-HVDC links are connected offshore on the AC side by a 10 km cable to form an offshore grid. A DC chopper is used on the grid-side of the converters to facilitate the onshore fault-ride through. The details of the offshore AC system and HVDC links can be found in [11] and the references therein.

Fig. 3: Mixed AC-DC system: (a) representative model of GB transmission system; (b) DC system.

3 Assessment indices

3.1 Frequency stability index

The Rate of Change of Frequency (RoCoF) is used to assess the frequency stability of the system. The RoCoF is a factor that describes how fast the frequency changes following a large-disturbance. This should not be above certain limits as fast decelerations may be deleterious for generators. The maximum allowable RoCoF values are calculated here numerically using a 100 ms measurement window as reported in [17].

3.2 Rotor angle stability indices

From the AC-side small-disturbance rotor angle stability perspective, the investigation focuses on the impact of various frequency control methods on the damping of the interarea mode of the system. The QR method has been used to evaluate the eigenvalues to the frequency of interest (i.e. 0.2–1.0 Hz), and the corresponding damping ratios are calculated. The large-disturbance rotor angle stability of the representative GB system is assessed here by the transient stability index (TSI) presented in [18]. The TSI is given as (2) [18]:

\[
TSI = \frac{360^\circ - \delta_{\text{MAX}}}{360^\circ + \delta_{\text{MAX}}}
\] (2)

In (2), \(\delta_{\text{MAX}}\) is the maximum rotor angle separation between two synchronous generators at any instant in time. In this study, \(\delta_{\text{MAX}}\) of any \(i\)th generator is evaluated with respect to the reference machine rotor angle \((\delta_{\text{ref}})\), as in (3) [18]:

\[
\delta_{\text{MAX}} = \delta_i - \delta_{\text{ref}}
\] (3)

3.3 Economic evaluation indicator

This section briefly presents the methodology for economic assessment. The costs associated with all strategies are calculated in this work by using present value and can be expressed as (4):

\[
D_{\text{tot}} = D_{\text{ini}} + \sum_{n=1}^{N} \frac{D_{\text{ann}}}{(1+r)^n}
\] (4)

In (4), \(D_{\text{tot}}\) is the total cost of frequency control strategy for \(N\) years, \(D_{\text{ini}}\) is the initial investment, \(D_{\text{ann}}\) is the operation and maintenance (O & M) cost, \(r\) is the discount rate used (in this case 6% [19]). The economic value of frequency control is estimated by the savings realized by utilizing various FRC strategies. The value is calculated using (5). Again the values in (5) are in present value.

\[
\text{Savings} = C_i - C_j
\] (5)

In (5), \(C_i\) is the cost associated with \(i\)th primary frequency control and \(C_j\) is the cost associated with \(j\)th primary frequency control. The cost associated with BESS, SC is given in Table 1.

<table>
<thead>
<tr>
<th>Device</th>
<th>Cost</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>BESS [19]</td>
<td>Installation</td>
<td>£ 85 per kVA</td>
</tr>
<tr>
<td></td>
<td>O &amp; M</td>
<td>£ 2.24 per KVA</td>
</tr>
<tr>
<td>SC [7]</td>
<td>Installation</td>
<td>£ 15.94 per kVA</td>
</tr>
<tr>
<td></td>
<td>O &amp; M</td>
<td>£ 0.62 per kVA</td>
</tr>
</tbody>
</table>

Table 1: Cost assumptions for BESS and SC.

The cost for VSC-HVDC based FRC control is not as straightforward as BESS and SC. The costs are mainly associated with the control and software modification in the onshore VSC-HVDC station and offshore WPP. These costs are assumed to be 0.27% of the investment cost associated with VSC-HVDC system and WPP as in [20]. The operating cost is assumed to be £0.05 per kVA based on [21]. The maintenance cost associated with VSC-HVDC FRC is assumed to be 2% of the investment cost for the controller.
4 Numerical simulation

The techno-economic assessments of the BESS, SC, and VSC-HVDC based FRC are presented in this section for various operating conditions.

4.1 Operating scenarios

The frequency response of the studied system is investigated here for the loss of a synchronous generator in the representative GB system. During the low load condition, the number of committed generators and headroom are usually small, and the system is likely to become more susceptible concerning frequency stability. Therefore, summer loading condition has been used for this study. In this study, four different DC link power levels are used. The FRC strategies presented in Table 2 are used to evaluate the system benefits.

### Table 2: Frequency regulation control strategies.

<table>
<thead>
<tr>
<th>Strategy</th>
<th>Description</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>SC</td>
<td>300 MVA capacity</td>
</tr>
<tr>
<td>2</td>
<td>BESS</td>
<td>150 MVA capacity</td>
</tr>
<tr>
<td>3</td>
<td>FRC in VSC-HVDC</td>
<td>Dual-loop frequency controller at grid-side VSC-HVDC</td>
</tr>
<tr>
<td>4</td>
<td>SC+FRC in VSC-HVDC</td>
<td>100 MVA capacity of SC and VSC-HVDC based dual-loop frequency controller</td>
</tr>
<tr>
<td>5</td>
<td>BESS+FRC in VSC-HVDC</td>
<td>50 MVA capacity of BESS and VSC-HVDC based dual-loop frequency controller</td>
</tr>
<tr>
<td>6</td>
<td>SC+BEss+FRC in VSC-HVDC</td>
<td>100 MVA SC, 50 MVA BESS with VSC-HVDC based dual-loop frequency controller</td>
</tr>
</tbody>
</table>

Table 2: Frequency regulation control strategies.

4.2 Frequency stability

Table 3 shows the RoCoF for various frequency control strategies. From the Table 3, it is evident that the RoCoF of the system is reduced considerably for strategy 6 (i.e. combine use of SC, BESS, and FRC at VSC HVDC system). Furthermore, it can also be seen that the FRC at VSC-HVDC provides better RoCoF performance than the strategy 1 (SC of 300 MVA) and strategy 2 (BESS of 150 MVA). This strategy supplies momentary active power to the system as well as reducing the active power consumption of the load for a short period following the outage of 1800 MW generation, results in a better RoCoF.

### Table 3: RoCoF for various control strategies.

<table>
<thead>
<tr>
<th>Strategy</th>
<th>RoCoF (Hz/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>600 MW DC link power</td>
</tr>
<tr>
<td>1</td>
<td>-0.3020</td>
</tr>
<tr>
<td>2</td>
<td>-0.3025</td>
</tr>
<tr>
<td>3</td>
<td>-0.2726</td>
</tr>
<tr>
<td>4</td>
<td>-0.2631</td>
</tr>
<tr>
<td>5</td>
<td>-0.2671</td>
</tr>
<tr>
<td>6</td>
<td>-0.2589</td>
</tr>
</tbody>
</table>

Table 3: RoCoF for various control strategies.

Comparably, the amount of active power ramping following the disturbances is small for strategy 1 and 2 compared to the other strategies. This, therefore, results in a higher RoCoF for these strategies.

4.3 Rotor angle stability

Fig. 4 shows the range of damping ratios (%) seen for the lowest damped electromechanical (EM) mode (i.e. interarea mode) for various FRC strategies under the variety of conditions simulated. From the results in Fig. 4, it is identified that the strategy 1 has the least positive impact on the damping of the interarea mode followed by strategy 2. Since no power modulation controller is employed in strategy 1 other than the stored energy at inertia, therefore, minimum variations and lower damping for interarea mode can be seen for this strategy. Comparably, there is no additional active power modulation based damping controller at BESS, therefore, strategy 2 has a lower positive influence on the damping of the interarea mode. From the results in Fig. 4, it is also evident that the strategy 3 could outperform the other FRC strategies. Furthermore, looking at the upper and lower bounds of the interarea mode damping, it can be concluded that the strategy 4, 5, and 6 have nearly the similar impacts on the damping of the interarea mode. Comparably, strategy 6 shows a little higher upper and lower bounds than strategy 4 and 5.

![Fig. 4: Interarea mode damping ratio (%) for various FRC strategies.](image-url)

Fig. 5 gives the range of TSI values obtained for the various FRC strategies under the wide variety of operating conditions considered (higher values imply higher levels of transient rotor angle stability). From the figure, it can be seen that the strategy 3 has the most positive impact on the large-disturbance stability of the system followed by strategy 5 and 2. From the figure, it is also evident that the TSI values for the system are not changing significantly under various operating conditions for strategy 1, 4, and 6, respectively. From the given results, it can be concluded that the system experiences the lowest large-disturbance stability margin for strategy 1. From the results given in Fig. 5, it is also evident that the utilization of SC with VSC-HVDC based FRC and SC with BESS and VSC-HVDC based FRC deteriorates the positive influence of BESS and VSC-HVDC based FRC on the large-disturbance stability of the system.
4.4 Financial analysis

Fig. 6 illustrates the cost related to the different FRC strategies. From the figure, it can be seen that the cost value of strategy 2 (i.e. 150 MVA BESS in the GB system) is the highest compared to the other strategies by a significant margin. This is due to the very high cost associated with BESS systems at present (although costs have been reducing). Furthermore, the recurring capital costs in every 6 years (lifetime of BESS) for BESS over the project time (i.e. 20 years) also contribute to this higher cost. A significantly lower cost would occur for strategy 3 (i.e. frequency control at VSC-HVDC system) since the costs of strategy 3 are consists of software and control modification, and O&M cost. These costs are not significant as compared to the capital costs of VSC-HVDC and offshore WPP system. The second lowest cost would occur for strategy 4 where a 100 MVA and FRC control at VSC-HVDC is used. The cost in strategy 4 is high as compared to strategy 3, mainly due to the refurbishment cost associated with using retired synchronous generators as SCs. The cost associated with strategy 3 is almost 35 times lower than the strategy 2, and 2 - 15 times lower than the other strategies considered in this study.

4.5 Summary

To showcase the full system benefits from various FRC strategies, radar plots of all performance indices are given in Fig. 7. These plots trace the system benefit indicators (i.e. worst cases for system indicators TSI, modal damping, RoCoF, and cost savings) on different axes. It should be noted that the scale of RoCoF is reversed so that for all analyses, the points near the centre are representative of lower margin, while the points on boundaries represent the higher margin. Additionally, the larger area implies the greater value. From the results in Fig. 7, it can be seen that the strategy 1 and 2 have minimal impacts on the dynamic stability performances of the system with reasonable cost saving for strategy 1 while, the strategy 2 is the most cost-intensive option (with zero savings as the benchmark against which other options are measured). From the analysis, it is apparent that the system experiences greater overall stability margins for strategies 3 and 5. However, the cost savings for strategy 3 are approximately 1.5 times larger than strategy 5. Comparably, satisfactory modal damping, RoCoF, and cost savings can be achieved by strategy 4 and 6. However, these strategies have an adverse impact on the large-disturbance angle stability of the system. Overall, it can be concluded that strategy 3 (FRC in VSC-HVDC) is the most feasible option based on techno-economic assessments presented in this work.
5 Conclusions

This paper has presented the results from investigations into the impacts of various FRC strategies for the representative GB system with appropriate dynamic parameters. The conclusions of this study provide useful insights and understanding of the possible technical and economic benefits realized by implementing FRC in VSC-HVDC system as compared to other frequency regulation strategies considered in this work. From the analysis conducted in this work, it is indicative that the integration of FRC at the VSC-HVDC would substantially contribute to the frequency stability of the system as compared to other strategies considered in this work. Moreover, the system may experience better small-and large-disturbance angle stability performance for FRC at the VSC-HVDC system as compared to the other strategies. The cost associated with FRC at the VSC-HVDC is very low as compared to other strategies stated in this work. Therefore, significant cost savings would be anticipated for the utility.

Acknowledgments

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