Wide area inter-area oscillation control system in a GB electric power system

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Abstract: A wide area control system (WACS) for the Great Britain (GB) power system is presented. This WACS is designed to enhance the GB system's small signal stability, i.e. improve the damping of the inter-area oscillatory modes between Scotland and England. This study mainly consists of two parts. In the first part, the conventional concept of high-voltage direct current (HVDC) and supplementary damping control modelling is presented. The model of HVDC and supplementary damping control are tested through the classic two-area model. In the second part, the operation of the proposed WACS is demonstrated using a full model of the GB power system. In addition to the demonstration of the major applications, some key factors that will influence the operation of the wide area inter-area oscillation damping control scheme will be tested and discussed. These factors include the time delay involved in wide area data transmission and the reactions between the additional HVDC damping controller and conventional power system stabilisers.

1 Introduction

Over the decades, the renewable energy policy against global warming has been bringing significant change to the electrical power systems in the Great Britain (GB), in terms of both the introduction of new power transmission technologies and changes in the nature of the generation. These changes would cause the operation of the GB power system to become more unpredictable and complex. Therefore, developing a wide area monitoring protection and control (WAMPAC) system will form an essential part of any attempts to enhance the stability and efficiency of the operation of the future GB power system. The R&D project, ‘WAMPAC in the future GB Power System’, was funded by National Grid Ltd., UK. The main objective of the project was to tailor a WAMPAC system that would be facilitated in the future GB power system. One of the biggest changes of the GB power system is that a large percentage of electrical energy would be generated from off-shore wind farms. A majority of the off-shore wind farms will connect to the power grid with the back-to-back HVDC link; hence, conventionally, they will not provide inertia to the system, as well as the on-shore double-feed wind farms, photovoltaic farms, and large battery stations. Coupled with the replacement of the conventional coal generators with the new wind farms, the inertia of the future UK power system will be reduced. This shortcoming, coupled with the increasing replacement of conventional generators with wind turbines, will cause the inertia of the future UK power system to be ~15–20% lower than it is currently [1].

Driven by legislative renewable targets in the UK, the minimum 6.6 GW of wind turbines in Scotland, the majority of the power generated by these wind turbines will be transferred to the remote load centres in Southern England. Therefore, this large increase in the generation capacity in Scotland will cause a large increase in the power flow between Scotland and England [2].

The increasing levels of power transfer between Scotland and England will require substantial power transmission line reinforcements and the deployment of new technologies to facilitate the transmission of ‘wind power’ from Scotland to England. To strengthen the power transfer capability at the interface, the National Grid Electricity Transmission (NGET) and Scottish Power Electricity Network are planning the installation of thyristor-controlled series capacitors (TCS Cs) into the inter-tie lines and new submarine high-voltage direct current (HVDC) links between Scotland and the North of Wales. As can be seen from Fig. 1, once these power electronic devices have been installed in the inter-tie lines, the additional inter-area oscillation damping controllers become available [3, 4].

In this paper, a wide area inter-area oscillation control scheme designed for the future GB power system is presented. In the first main part, a process for designing inter-area oscillation damping controller using power electronic devices is presented. The typical two-area system is used to illustrate the damping control design process. There is no power system stabiliser (PSS) installed in the system; the system is representative of the sort that may benefit from the use of power electronic devices for damping inter-area oscillations. In the second main part, the operation of the proposed WACS is demonstrated using a full model of the GB power system. This model was created in the DiG SILENT PowerFactory software package. In addition to the demonstration of the major applications, some key factors that will influence the operation of the wide area inter-area oscillation damping control scheme will be tested and discussed. These factors include the time delay involved in wide area data transmission, and the reactions between the additional HVDC damping controller and conventional PSSs.

2 Using HVDC for damping inter-area oscillations

2.1 HVDC power converter modelling

In this section, the process for designing an HVDC supplementary controller for damping inter-area oscillations occurred in a classic two-area system is presented. For illustrating the application of HVDC damping control, a typical two-area system with an HVDC link, shown in Fig. 2, was constructed using ‘DiG SILENT PowerFactory’.

There are two types of power converters: current source converter (CSC) and voltage source converters (VSC). Here, only the CSC power converters are introduced and used. A power converter has two operation modes: rectifier mode and inverter mode. The operation mode of a converter is determined by the firing angle, \(\alpha\), of the controlled valves. With a firing angle of \(0°<\alpha<90°\), a converter operates in the rectifier mode, whereas when the firing angle is \(90°<\alpha<180°\), a converter operates in the inverter mode. A rectifier converts electric power from the AC system to
the DC system, whereas an inverter converts electric power from the DC system to the AC system. Fig. 3 shows the equivalent circuit of a rectifier with a one six-pulse bridge [5].

Fig. 3 Equivalent circuit of a rectifier with a one six-pulse bridge

Fig. 4 Equivalent circuit of an inverter with a one six-pulse bridge

Fig. 5 Equivalent circuit of the monopolar HVDC Link

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practice is to describe an inverter using the ignition advance angle $\beta$ ($\beta = \pi - \alpha$), instead of $\alpha$.

Fig. 5 shows the equivalent circuit of monopolar HVDC, the rectifier at the power sending terminal, the inverter at the power receiving terminal, and the DC transmission line. Combining this configuration with the equivalent circuits of power converters allows the equivalent circuit of a monopolar HVDC link to be formed.

Generally, the amount of active power to be transferred over the DC link is firstly determined. Then, the direct voltage at the power receiving terminal is held at 1.0 pu through $\beta$ control of the inverter (see Fig. 6). In $\beta$ control of the inverter, the input signal is the error between the voltage reference and the real-time voltage measurement. This error is processed using a proportional–integral (PI) regulator to calculate a new value for the firing angle. With the pre-determined power transfer and a constant voltage at the inverter terminal, the direct current through the DC link can be directly calculated. Using this calculated value as a current reference, the rectifier’s $\alpha$ control acts to hold the direct current at the reference value by adjusting the firing angle $\alpha$ (see Fig. 7).

2.2 System performance without the HVDC damping controller

At a steady state, modal analysis was used to find the system’s oscillatory modes. The eigenvalues associated with all of the oscillatory modes are shown in Fig. 8.

As can be seen from Fig. 8 there are eight oscillatory modes in this system and they are all well damped except for the inter-area oscillatory mode ($\lambda_{\text{inter}} = -0.0128 \pm 3.212$ damping ratio = 0.3%). A non-linear simulation was performed to show that the inter-area oscillatory mode under which the generators in the areas swing against each other after disturbances. For exciting the inter-area mode, the mechanical torque of generator 2 was increased by 0.01 pu at 0 s, the mechanical torque of generator 4 was simultaneously reduced by 0.01 pu. Fig. 9 shows the generator...
rotor speed responses to this pair of small disturbances. The shape of the inter-area mode can be clearly observed in the responses, i.e. the change of the generator rotor speeds in area 1 is always in anti-phase with the change of the generator rotor speeds in area 2.

Fig. 10 shows the frequency response at two locations in the system: one is measured in area 1 (at bus 3) and the other is measured in area 2 (at bus 5). As can be seen from Figs. 9 and 10, the inter-area mode is not damped.

2.3 System performance with the HVDC damping controller

Fig. 11 gives a block diagram of a supplementary damping controller for HVDC. The input of the supplementary HVDC damping controller is the frequency difference between area 1 and area 2; one frequency is measured at bus 3 and the other one is measured at bus 5. The output of this damping controller is used to modify the current reference of the rectifier's $\alpha$ control.

Having integrated the HVDC damping controller into the system, the modal analysis was repeated and nine oscillatory modes were found in the system. The analysis of the participation factors shows that the new oscillatory mode is an HVDC control mode. Fig. 12 shows the eigenvalues of the system's oscillatory modes for different controller gains.

As the gain, $K_d$ (see Fig. 11) of the HVDC damping controller increases the poorly damped inter-area oscillatory mode moved directly to the left, whereas the HVDC control mode moved directly to the right. When the damping controller's gain increased to 1600, the inter-area mode started to move back to the right; this means that the damping ratio of the inter-area mode starts to decrease.

Non-linear time-domain simulations were used to check the ability of the HVDC damping controller to properly damp inter-area oscillations. The behaviour of the HVDC damping controller during large disturbances was also tested. At 1 s, a permanent three-phase short-circuit fault was simulated at the mid-point of line 6; after 100 ms, the faulted line was disconnected. The responses of the generator rotor speeds to the three-phase fault with and without an HVDC damping controller are presented in Fig. 13. As seen from the simulation results, the HVDC damping controller has shown its robustness in damping inter-area oscillations after the system is subject to a large disturbance.

In addition, Fig. 14 presents the responses of the inter-area power flow (line 3) to the large disturbance with different damping controller gains. As before, when the controller gain is increased, the damping is also increased; this allows the system to be stabilised more quickly from the large disturbance.

3 WACS in the GB power system

3.1 GB power system modelling

A GB power system model used for the GB WACS study was constructed in DlgSILENT PowerFactory. This system consists of three areas: the Scottish Power Transmission Network (SPTN), the Scottish Hydro-Electric Transmission Network, and the National Grid Electricity Transmission Network (NGETN). There are ~200 synchronous generators in the system, and ~50% are equipped with PSSs. Wind farms consisting of fixed speed wind turbines are
modelled as groups of induction machines, and the wind farms consisting of double-feed wind turbines are modelled as static generators with Automatic Voltage Regulator (AVR). In addition, some key substations in NGETN have dynamically controlled SVCs intended for the purpose of maintaining the bus voltages at an acceptable level. The loads in the system model are modelled as constant impedance loads for all operation conditions.

As part of the network, 500 kV CSC-HVDC links are installed between the 400 kV substations at Hunterston and Deeside, to enhance the power transfer capability of the transmission corridors between Scotland and England. At a heavy-load condition, these two HVDC links transfer 1900 MW of active power from Southern Scotland to Northern Wales, while 2400 MW of active power is transferred over the AC transmission lines.

3.2 Inter-area oscillations study in the GB power system

In order to excite the inter-area oscillatory mode in the GB power system, a large disturbance was initiated in the power transmission corridor between SPTN and NGETN. This disturbance was a permanent three-phase short-circuit fault simulated at the mid-point of one of the transmission lines connecting the substations at Torness and Eccles. This fault was simulated at 1 s, and after 100 ms, the faulted line was disconnected. The inter-area power flow on one of the transmission lines connecting the Harker and Hutton substations was used for the inter-area oscillation damping assessment. Fig. 15 gives the locations of the faulted transmission line and the line selected for monitoring the inter-area oscillations.

To observe the inter-area oscillations associated with the generators in Scotland swinging against the generators in England, the system frequencies across the GB power transmission network were monitored. These system frequencies were measured at the terminals of some of the large generators (>500 MVA) that are operating at different locations in GB. The locations of the large generators selected for the monitoring of inter-area oscillations are also presented in Fig. 15.

Fig. 15 Locations of the monitoring of the inter-area oscillations in the GB power system [6]

Fig. 16 Oscillatory inter-area power flow on the Harker–Hutton line after a large disturbance

Fig. 17 System frequency variations caused by a large disturbance

Fig. 18 Oscillatory inter-area power flow caused by a large disturbance in the original and PSSs-reduced GB system

Fig. 19 System frequency variations caused by the large disturbance in the PSSs-reduced system

Fig. 16 presents the oscillatory inter-area power flow (over the Harker–Hutton line) caused by the large disturbance. As seen from the response of the inter-area power flow to the disturbance, the inter-area oscillatory mode is well damped in the GB power system. Fig. 17 shows the system frequency responses to the large disturbance. The frequencies measured in Scotland (PEHE, LOAN, and HUER) were closely coupled and swinging around the frequencies measured in England.

To create more oscillatory behaviour for observing the inter-area oscillations between Scotland and England, some conventional PSSs were removed from service. The same disturbance (a three-phase short-circuit fault on the Torness–Eccles line occurring at 1 s and cleared after 100 ms) was simulated to provoke a lightly damped inter-area oscillation. Fig. 18 presents the oscillatory inter-area power flow transferred over the Harker–Hutton line. Comparing this response to that of the original system, it was seen that the damping of the inter-area oscillation mode was significantly reduced.

Fig. 19 presents the system frequency variations caused by the large disturbance in the PSSs-reduced system. As seen from the simulation results, the inter-area mode dominated the system frequency variations, i.e. the system frequency variations in Scotland were nearly in anti-phase with the frequency variations in England. The inter-area oscillation associated with the generators in Scotland swinging against the generators in England was clearly observed, even though the inter-area oscillation was also influenced by local oscillation modes at the beginning of the dynamic period. Fig. 20 presents the system frequency variations measured from the substations Hunterston (HUNT) and Deeside...
The inter-area oscillation mode was also clearly observed, i.e. the frequency variation measured in the HUER substation was more or less anti-phase to the frequency variation measured in the DEES substation.

As seen from these simulation results, after a number of PSSs were removed from service, the damping of the inter-area oscillatory mode was reduced. This operational condition will probably emerge in as the system inertia will be significantly reduced due to the integration of a large amount of offshore wind farms [1]. Since offshore wind farms will connect to the power grid using back-to-back VSCs, they will not provide inertia to the system. Coupled with the increasing replacement of conventional generators with the offshore wind farms, the inertia of the future UK power system will be largely reduced. As a number of power electronic devices such as HVDC and TCSC will be installed to strengthen the Scotland–England interconnection, there is an essential need to establish a wide-area inter-area oscillation control system to extract maximum benefit from these power electronic devices and improve the system damping.

3.3 Wide area inter-area oscillation control using HVDC

The damping ratio of the inter-area mode was reduced to \( \sim 5\% \) after a number of PSSs were removed from service. With this level of damping, it is essential to develop an additional control system that uses the two HVDC links to improve the damping of the inter-area mode. The fundamentals of HVDC supplementary control design were introduced in Section 2. Fig. 21 gives a schematic diagram of the HVDC damping control system. The frequency oscillation between the HUER and DEES substations allowed the clear observation of the inter-area mode (see Fig. 21). Therefore, the difference between the two frequencies was used as the input signals for the HVDC damping control system. The signals, \( \Delta f \), generated by the damping controllers, were added to the current references of the rectifier controllers to dynamically modulate the DC power.

To check the abilities of the HVDC damping controllers to improve the damping of the inter-area mode, the same disturbance was used as before. At 1 s, a permanent three-phase short-circuit fault was simulated at the mid-point of one of the transmission lines connecting substations Torness and Eccles; after 100 ms, the faulted line tripped. Figs. 22 and 23 present the responses of the generator rotor speeds to the large disturbance with and without the wide area control.

Fig. 24 shows the response of the inter-area power flow on the Harker–Hutton line to the large disturbance, with and without HVDC damping control uses the two HVDC links to improve the damping of the inter-area mode. As confirmed by these simulation results, the HVDC damping controllers allow the system to be stabilised much more quickly after the inception of the large disturbance.

3.4 Impact of time delays on wide-area control

Wide area closed loop control systems use remote signals as feedback input signals. The dependence of the control system on wide area signals makes the time delay involved in their transmission of a significant concern. The time delay of the data transmission can vary from tens to hundreds of milliseconds. It depends on the communication distance, protocols, and time consumed by numerical calculations [7]. The delays involved in the transmission of a wide area signal can be defined as follows, with reference to Fig. 25. A packet of measurements (real time...
An oscillatory signal produced by a Phasor Measurement Unit (PMU) is tagged with a time stamp defined as ‘T1’, and then the measurements are transmitted to the wide area monitoring and control system (WAMCS) centre. The WAMCS centre calculates the corresponding commands for the HVDC converter control and sends these commands to the remote HVDC rectifier station. The time when the execution units in the HVDC converter stations receive these commands is defined as ‘T2’. The difference between ‘T2’ and ‘T1’ is defined as the time delay of the data transmission in the wide area control system.

Fig. 26 presents the effects of different time delays in the wide area damping controllers (50–200 ms). As seen from the simulations, the high-frequency oscillatory component disappeared when the time delay increased. In addition, when the time delay increased to 150 ms, the inter-area oscillation became unstable as the time delay approached 700 ms.

3.5 Interaction between PSSs and HVDC damping control

As seen from the simulation results, the HVDC damping control system has shown its powerful capability to stabilise inter-area oscillations when a number of PSSs are removed from the GB power system. This capability exists because the additional damping control system has very strong influence on the dynamic behaviour of the system. This strong influence could also have unforeseen negative effects. To ensure that the new HVDC damping control system does not have negative effects on the GB power system, the interaction between the PSSs that were removed form service and the new HVDC damping controllers was investigated.

With all of the PSSs in service, the same simulations were used, with and without the HVDC damping control. In these tests, the effect of time delay was not taken into account. Figs. 28 and 29 present the responses of the local system frequencies to the large disturbance. As seen from the simulations results, the new wide area damping control system has changed the dynamics of the original system (all PSSs in service). However, the responses of the system are still well damped. The new HVDC damping control system slightly improves the damping of the generators in Scotland (PEHE, LOAN, and HUER). The new HVDC damping control system did not introduce negative effects to other the generators.

The oscillatory inter-area active power flows (over the Harker–Hutton line) caused by the disturbance in the scenario, with and without HVDC damping control, are shown in Fig. 30. The HVDC additional damping control has changed the response of the inter-area power flow during disturbances. A larger deviation of the inter-area power flow was introduced by the HVDC damping control system; the system with HVDC damping control took longer time to stabilise at a new steady state after the large disturbances.
Conclusion

In this paper, a proposed WAMCS, designed for enhancing the small signal stability of a future GB power system, has been completely presented.

As the first part of the paper, the process of designing an inter-area oscillation damping controller using HVDC has been presented within the classic two-area system. The results of the damping analyses performed here, in both the frequency and time domain, demonstrate that the proper control of HVDC installed in the inter-area power transmission corridor can significantly improve the damping of the inter-area oscillation mode. Non-linear simulations are used to assist the conventional eigenvalue analysis. These time-domain simulations through a single large disturbance confirm the ability and robustness of the HVDC damping control schemes.

In the second main part, the proposed WAMCS are demonstrated in the full GB power system model. To investigate the inter-area oscillations associated with the generators in Scotland swinging against the generators in England, a permanent three-phase fault was introduced to one of the inter-tie lines between Scotland and England. As seen from the system response (inter-area active power flow) to the disturbances, the inter-area mode was well damped in the original GB power system. However, after a number of PSSs were removed from service, the damping of the inter-area mode was significantly reduced. The wide area HVDC damping control system has shown that, by dynamically modulating the DC power flow, it can be a powerful tool for improving the damping of the inter-area oscillatory mode. With this application, the power transfer capacity of the inter-area transmission lines would be increased.

The influence of the time delay on the WACS has been discussed, and the effect of the WACS was gradually reduced when the time delay increased. When the time delay increased to a certain range (~150–200 ms), a high-frequency oscillatory component was introduced into the inter-area oscillations. Finally, the interactions between the HVDC wide area damping control system and the conventional PSSs were investigated. The new wide area damping control system has changed the dynamics of the original system. However, the responses of the system to a large disturbance were still well damped. The damping of some generators has been further improved by the wide area damping control system, and it did not introduce obvious negative effects to other the generators.

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Fig. 30 Influence of HVDC damping control on the inter-area power flow in a complete GB system