Model Integration and Control Interaction
Analysis of AC/VSC HVDC System

A thesis submitted to The University of Manchester for the Degree
of Doctor of Philosophy
in the Faculty of Engineering and Physical Sciences

2015

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Nomenclature

**Abbreviations and Acronyms**

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>AC</td>
<td>alternating current</td>
</tr>
<tr>
<td>ACS</td>
<td>average cold spell</td>
</tr>
<tr>
<td>AGC</td>
<td>automatic generation controls</td>
</tr>
<tr>
<td>AVR</td>
<td>automatic voltage regulator</td>
</tr>
<tr>
<td>AWC</td>
<td>Atlantic wind connection</td>
</tr>
<tr>
<td>CCGT</td>
<td>combined cycle gas turbine</td>
</tr>
<tr>
<td>CSC</td>
<td>current source converter</td>
</tr>
<tr>
<td>CSG</td>
<td>China Southern Power Grid</td>
</tr>
<tr>
<td>CTL</td>
<td>cascaded two-level</td>
</tr>
<tr>
<td>DC</td>
<td>direct current</td>
</tr>
<tr>
<td>FACTS</td>
<td>flexible alternating current transmission system</td>
</tr>
<tr>
<td>FB</td>
<td>feedback</td>
</tr>
<tr>
<td>FF</td>
<td>feedforward</td>
</tr>
<tr>
<td>GB</td>
<td>Great Britain</td>
</tr>
<tr>
<td>GTO</td>
<td>gate turn-off thyristor</td>
</tr>
<tr>
<td>GOV</td>
<td>turbine governing control systems</td>
</tr>
<tr>
<td>HVDC</td>
<td>high voltage direct current</td>
</tr>
<tr>
<td>IEEE</td>
<td>institute of electrical and electronics engineers</td>
</tr>
<tr>
<td>IGBT</td>
<td>insulated gate bipolar transistor</td>
</tr>
<tr>
<td>LCC</td>
<td>line commutated converters</td>
</tr>
<tr>
<td>LPF</td>
<td>low pass filter</td>
</tr>
<tr>
<td>MIMO</td>
<td>multi-input multi-output</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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<td>--------------</td>
<td>--------------------------------------------------</td>
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<tr>
<td>MMC</td>
<td>multi-level modular converter</td>
</tr>
<tr>
<td>MSC</td>
<td>mechanically switched capacitors</td>
</tr>
<tr>
<td>MTDC</td>
<td>multi-terminal DC system</td>
</tr>
<tr>
<td>NETS</td>
<td>national electricity transmission system</td>
</tr>
<tr>
<td>NGET</td>
<td>National Grid Electricity Transmissions</td>
</tr>
<tr>
<td>ODIS</td>
<td>offshore development information statement</td>
</tr>
<tr>
<td>OPWM</td>
<td>optimal pulse-width modulation</td>
</tr>
<tr>
<td>PCC</td>
<td>point of common coupling</td>
</tr>
<tr>
<td>PLL</td>
<td>phase locked loop</td>
</tr>
<tr>
<td>PMU</td>
<td>phasor measurement unit</td>
</tr>
<tr>
<td>POD</td>
<td>power oscillation damping</td>
</tr>
<tr>
<td>PSS</td>
<td>power system stabilizer</td>
</tr>
<tr>
<td>PWM</td>
<td>pulse-width modulation</td>
</tr>
<tr>
<td>RGA</td>
<td>relative gain array</td>
</tr>
<tr>
<td>ROCOF</td>
<td>rate of change of frequency</td>
</tr>
<tr>
<td>SCR</td>
<td>short circuit ratio</td>
</tr>
<tr>
<td>SG</td>
<td>synchronous generator</td>
</tr>
<tr>
<td>SGCC</td>
<td>State Grid Corporation of China</td>
</tr>
<tr>
<td>SISO</td>
<td>single-input single-output</td>
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<tr>
<td>SMIB</td>
<td>single machine infinite bus</td>
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<tr>
<td>STATCOM</td>
<td>static synchronous compensator</td>
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<tr>
<td>SVC</td>
<td>static VAr compensator</td>
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<tr>
<td>TGR</td>
<td>transient gain reduction</td>
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</table>
List of Symbols

DC System and VSC symbols

- $C_{eq}$: converter DC side equivalent capacitor
- $C_{dc}$: DC cable capacitance
- $e$: converter AC side voltage
- $i$: converter AC side phase current
- $k_p$, $k_{droop}$: controller proportional gain
- $k_i$: controller integral gain
- $P$: real power
- $Q$: reactive power
- $i_{dc}$: DC current
- $i_a$: arm current
- $L$: inductance
- $L_{dc}$: DC cable inductance
- $L_s$: limb inductance
- $P_M$: modulation index
- $R$: resistance
- $R_{dc}$: DC cable resistance
- $v$: point of common coupling bus voltage
- $V_{dc}$: DC link voltage
- $X$: reactance
- $\theta$: point of common coupling bus angle
- $\sigma$: angle difference between frames
**AC System symbols**

- **A**  state matrix
- **B**  input matrix/susceptance
- **C**  output matrix
- **D**  feedforward matrix
- **emf**  electromotive force
- **I**  identity matrix
- **x**  state variable/state vector/unknowns
- **u**  input/input vector
- **y**  output/output vector
- **λ**  eigenvalues
- **Ψ, ψ**  left eigenvector
- **Φ, ϕ**  right eigenvector
- **ξ**  damping ratio
- **R**  residue
- **E**  synchronous generator terminal voltage
- **Ig**  synchronous generator terminal current
- **δ**  generator/converter AC side angle
- **E_{id}**  excitation voltage
- **H**  inertia constant
- **P_{me}**  mechanical and electric power
- **V_{pss}**  power system stabilizer output signal
- **K_{A,R}**  AC system control gains
- **f**  frequency
- **phi**  AC bus angle
- **V_{ac}**  AC bus voltage
- **ω**  speed/modal frequency (imaginary part)
- **Y**  admittance
- **T_{a+ΔR+ΔA+B+ΔGR}**  time constant
- **T_{mA-e}**  mechanical and electrical torque
- **G(s)**  plant model
**Superscript**

* reference quantity of the controller
', transient
'' sub-transient
· derivative

**Subscript**

a,b,c electrical phases in three-phase system
dq, DQ direct and quadrature axes (dq domain quantities)
ref reference quantity of the controller
pss power system stabilizer
pcc point of common coupling bus
i,j random numbers
l,2...n various constants
α,β alpha-beta domain quantities
vsc voltage source converter
g synchronous generator
max maximum value
min minimum value
th thévenin equivalent
droop droop gain setting
0 initial value
o operating point value
Abstract

Model Integration and Control Interaction Analysis of AC/VSC HVDC System
Li Shen, Doctor of Philosophy, The University of Manchester, April 2015

The development of voltage source converter (VSC) based high voltage direct current (HVDC) transmission has progressed rapidly worldwide over the past few years. The UK transmission system is going through a radical change in the energy landscape which requires a number of VSC HVDC installations to connect large Round 3 windfarms and for interconnections to other countries. For bulk power long distance transmission, VSC HVDC technology offers flexibility and controllability in power flow, which can benefit and strengthen the conventional AC system. However, the associated uncertainties and potential problems need to be identified and addressed. To carry out this research, integrated mathematical dynamic AC/DC system models are developed in this thesis for small disturbance stability analysis. The fidelity of this research is further increased by developing a dynamic equivalent representative Great Britain (GB) like system, which is presented as a step-by-step procedure with the intention of providing a road map for turning a steady-state load flow model into a dynamic equivalent.

This thesis aims at filling some of the gaps in research regarding the integration of VSC HVDC technology into conventional AC systems. The main outcome of this research is a systematic assessment of the effects of VSC controls on the stability of the connected AC system. The analysis is carried out for a number of aspects which mainly orbit around AC/DC system stability issues, as well as the control interactions between VSC HVDC and AC system components. The identified problems and interactions can mainly be summarized into three areas: (1) the effect of VSC HVDC controls on the AC system electromechanical oscillations, (2) the potential control interactions between VSC HVDC and flexible alternating current transmission systems (FACTS) and (3) the active power support capability of VSC HVDC for improving AC system stability.

The effect of VSC controls on the AC system dynamics is assessed with a parametric sensitivity analysis to highlight the trade-offs between candidate VSC HVDC outer control schemes. A combination of analysis techniques including relative gain array (RGA) and modal analysis, is then applied to give an assessment of the interactions – within the plant model and the outer controllers – between a static synchronous compensator (STATCOM) and a VSC HVDC link operating in the same AC system. Finally, a specific case study is used to analyse the capability of VSC HVDC for providing active power support to the connected AC system through a proposed frequency droop active power control strategy.
Declaration

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¹ http://documents.manchester.ac.uk/DocuInfo.aspx?DocID=487
² http://www.manchester.ac.uk/library/aboutus/regulations
Acknowledgement

First and foremost, I would like to express my sincere gratitude to my supervisors Prof. Mike Barnes and Prof. Jovica V. Milanović who have been tremendous mentors for me. Their expertise, invaluable guidance, and patience, added considerably to my PhD studying experience. My appreciation must also go to Prof. Keith Bell in the University of Strathclyde for his guidance on network modelling and insightful comments for this research.

I would like to acknowledge Dr Paul Coventry in National Grid Electrical Transmission plc (NGET) for sponsoring and supporting this work. He and his team in NGET have provided me with very useful and valuable suggestions with industrial context which has greatly strengthened my understanding in this research.

Also thanks go to my fellow researchers (Antony Beddard, Atia Adrees, Bin Chang, Chengwei Gan, Ding Wu, Jeganathan Vaheeshan, Jesus Carmona Sanchez, Manolis Belivanis, Oliver Cwikowski, Robin Preece, Siyu Gao, Ting Lei, Tingyan Guo, Wenyuan Wang etc.) in both Power Conversion (PC) and Electrical Energy and Power Systems (EEPS) groups at the University of Manchester for their good companionship, for the discussions and debates we have, and for the exchanges of knowledge, which all helped enrich my experience of this research work.

Finally but most importantly, I would like to extend my deepest appreciation to my fiancée Ran Ran and my parents, for their support, encouragement and unwavering belief in me, which has helped me to get over obstacles and made my PhD far more enjoyable.

Manchester, March 2015

Li Shen
To my parents
Chapter 1. Introduction and Review of AC/DC Interaction

This chapter introduces the background and objectives of the research work. A review on the state of art and related studies is also provided.

1.1. Transmission with VSC HVDC

Development of HVDC Technology

With the development of high-voltage, high-power, fully controlled semiconductor devices, high voltage direct current (HVDC) transmission systems have continued to advance over the past few years. Since the first commercial installation in 1954 (Gotland 1 in Sweden), a vast amount of HVDC transmission systems have been installed worldwide. The fundamental process that occurs in an HVDC system is the AC-DC-AC conversion. Two main technologies have been used in the HVDC links installed so far: (1) line commutated converter based HVDC (LCC HVDC) which uses thyristor technology [1, 2]; and (2) voltage source converter based HVDC (VSC HVDC) [3-11], which uses transistors such as the insulated gate bipolar transistor (IGBT).

Because thyristors can only be turned on (not off) by control actions and they rely on the external AC system to affect the turn-off process, the controllability of LCC HVDC is limited. The DC current in a LCC HVDC does not change direction. It flows through a large inductance, and it can be considered almost constant. The converter behaves approximately as a current source which injects current with harmonics to the connected
AC system. Therefore, it is also sometimes referred to as a current source converter (CSC). LCC HVDC is normally used in high power rating applications.

The first commercial VSC HVDC project was built by ABB for transmission in 1999 in Gotland, Sweden [3]. With the self-commutated VSC HVDC technology where both turn-on and turn-off of the semi-conductors can be controlled, a spectrum of operational advantages is introduced, notably the ability of feeding passive networks, independent power control and enhanced power quality. A constant polarity of DC voltage can be maintained by VSC HVDC. This facilitates the construction of multi-terminal DC system (MTDC) that is seen as the base for the promising “future DC grid”. Comprehensive comparisons between practical projects using LCC and VSC technologies with similar rating are available in [5]. VSC HVDC technology has now evolved to the point where it is considered the main candidate for the connection of large renewable energy sources located far-offshore. It is also a leading candidate for the reinforcement of onshore networks through the use of underground or undersea cable links. This is likely to result in its widespread proliferation in integrated AC/DC systems. However, many challenges remain before the potential impact of this change to system architecture is thoroughly understood.

Since the first appearance of VSC HVDC, there have been several evolutions of converter topologies introduced by different companies (e.g. Siemens, ABB, Alstom Grid, etc.). The trend is moving from two-level converter topology towards multi-level [2]. The advent of multi-level modular converter (MMC) [6, 7] technology enhanced the quality of the converter output voltage waveform, allowing harmonic filtering equipment to be reduced or even eliminated. However, in comparison with the two-level converters, the modelling of MMC becomes more sophisticated [12-15], and more complicated control systems are required for switching in and out the sub-modules in the converter arms. Special techniques for additional control requirements such as capacitor voltage balancing control, circulating current suppression, etc. are proposed [16-18]. With MMC converters, converter losses are seen reduced to about 1%, which is comparable to LCC HVDC [7] (see Appendix B2 for further details on converter losses).
Chapter 1. Introduction and Review of AC/DC Interaction

The first MMC based commercial project Trans Bay Cable came online in 2010, USA [8]. The typical MMC converter topology is presented in Fig. 1.1.

![MMC and SM topology](image)

Sub-Module (SM)

Gone Green Scenario

Slow Progression Scenario

Development of UK Offshore Windfarm Connections and Interconnectors

The National Electricity Transmission System (NETS) in UK is in a period of radical change in the energy landscape. Four future scenarios have been created by NETS considering their affordability and sustainability: Gone Green, Low Carbon Life, Slow Progression and No Progression [19].
Fig. 1.2 presents the generation mix with the fast developing (Gone Green) and slow developing (Slow Progression) future scenarios. It is seen that wind generation reaches approximately 47GW by 2035 (35.5GW of this being offshore) and interconnector capacity reaches 11.4GW with the Gone Green scenario. Even with a Slow Progression scenario, the capacity growth in wind and interconnectors by 2035 is still significant — 27GW and 7.4GW for wind and interconnectors respectively.

Fig. 1.3 Overview of potential VSC HVDC applications in UK.

The development of UK’s offshore wind power from 2015 is mainly known as the Round 3 projects (Fig. 1.3), with a potential capacity of 32GW. According to National Grid's Offshore Development Information Statement (ODIS) [19], the newly leased Round 3 offshore windfarm projects normally have large power generation and are located far from shore, implying potential applications of VSC HVDC transmissions. NETS also proposes to increase interconnectivity between EU member states to further
secure system operation, facilitate competition and support the efficient integration of renewable generation. This also gives rise to VSC HVDC technology due to its fast and independent bidirectional power control capability. The operational interconnectors as well as the contracted interconnectors are summarized using Fig. 1.3. The two embedded point-to-point HVDC links – the LCC based Western link and the Eastern link (planning stage) – are also presented.

**VSC HVDC System Configurations**

VSC HVDC systems allow independent real and reactive power control. When they are combined with offshore windfarms or in parallel operation with onshore AC systems, use of VSC HVDC can benefit the onshore power flows. For instance, power flow in the AC onshore system may be directed away from areas of electrical constraint by boosting or restricting power flow in the HVDC systems.

For both onshore-to-windfarm or onshore-to-onshore connections, VSC HVDC systems are typically configured as a symmetrical monopole, as presented in Fig. 1.4. This type of topology uses two high-voltage conductors, each operating at half of the DC voltage, with a single converter at each end. In this arrangement, the converters are earthed via high impedance and there is no earth current. There are other commonly seen topologies for HVDC links which are well summarized in [20].

![VSC HVDC link topology](image)

The symmetrical monopole configuration has been applied in a number of practical point-to-point VSC HVDC projects for both onshore and windfarm connections. The

---

1 Some typical VSC HVDC projects are:
1) Parallel lines and interconnectors: Trans Bay Cable, Cross Sound Cable, EWIC, Estlink, etc.
symmetrical monopole arrangement is popular with VSC HVDC, but it is uncommon with LCC HVDC where bipolar topologies are preferred. Further development of VSC HVDC technology will probably result in MTDC grid. Different design approaches are proposed in ODIS for windfarm connections, from stage 1 (point-to-point connections) to stage 3 (interconnected AC/DC cables) are presented in Fig. 1.5.

The coordinated strategy is essentially a MTDC system which provides alternative paths for the power from windfarms to the onshore grid when any single offshore HVDC cable is lost. However, sufficient transmission capacity needs to be ensured to accommodate the required generation output following an outage. Similar VSC MTDC configurations are seen in Fig. 1.6 with the Atlantic wind connection (AWC) [9], which will be built through multiple phases — from a paralleled point-to-point link at the start to a MTDC grid when completed.
Actual implementation of VSC MTDC is seen in the Nanao three-terminal ±160kV project delivered by CSG (China Southern Power Grid) in 2013, which is based on MMC converter technology [10, 11]. There are two sending ends and one receiving end with the corresponding converter rating presented in Fig. 1.7. It can be seen from this practical case that an “interconnected symmetrical monopole” system topology is adopted.

Another MMC based MTDC project was also constructed in Zhoushan, China, by SGCC (State Grid Corporation of China) which consists of five terminals with a voltage rating of ±200kV for integrating windfarm generations located in several surrounding islands [21].

**HVDC Circuit Breaker**

For the acceptance and reliability of large scale DC systems, especially MTDC networks, it is crucial to have HVDC circuit breakers available. Instead of shutting down the whole DC system\(^1\), DC breakers are essential to allow DC grid the ability to isolate any certain part of the system when a DC fault occurs. When comparing the requirements for DC breakers to conventional AC system breakers, the main difference is the absence of a natural current zero. DC breakers need to be able to quickly interrupt

\(^1\) Windfarm connections based on VSC HVDC are protected by AC side breakers which de-energise the whole DC link during fault conditions.
fault current and dissipate the energy stored in the DC system inductors. Different topologies of DC breaker prototypes are currently under investigation by companies like ABB [22] and Siemens [23]. However, since there are still no standard DC breakers commercially available and there are no practical implementations in the HVDC projects so far, DC breakers are not considered in the DC system models of this research at current stage.

1.2. Review of AC/DC Interaction

Normal power system operation requires stable and reliable control of both real and reactive power. To keep its integrity, a balance between generation and demand needs to be maintained. VSC HVDC technology features its capability of independent real and reactive control within its capability curve. This can be useful to support the connected AC system with the best mixture of active and reactive power when required. This section addresses the state of art and the further work required for modelling and interaction studies regarding VSC HVDC and AC systems.

Modelling of Integrated AC/DC Systems

The challenge for today’s electric power systems is to seek enhancement in bulk power transmission capability, renewable generation reliability and flexible power flow controllability. The option of conventional AC expansion is often limited by environmental constraints or problems with voltage and power instability. In such cases, upgrading with advanced VSC HVDC transmission techniques and flexible alternating current transmission systems (FACTS) become attractive alternatives. This will lead to integrated AC/DC systems where potential interactions in the system plant models or controls need to be carefully investigated.

For studies regarding AC/DC interactions, integrated AC/DC system models need to be developed. This normally begins with building steady-state load flow models and then develops towards dynamic models. One of the very prominent problems in such process is the power flow calculation for integrated AC/DC systems. Much work has been done in this respect for detailed AC/MTDC power flow calculation. A general classification
Chapter 1. Introduction and Review of AC/DC Interaction

distinguishes between unified [24-26] and sequential methods [27]. The unified method includes the effect of the DC links in the Jacobian to solve a combined AC/DC Jacobian matrix. The equations of an integrated AC/DC system are solved simultaneously in each iteration process for the unified method, and many techniques have been used to improve its efficiency. On the other hand, in a sequential power flow method, the AC and DC equations are solved separately in each iteration. The main advantage is that it becomes easy to combine new DC power flow algorithms to some well-developed AC power flow solution techniques. The AC/DC load flow calculation techniques form the basis of steady-state AC/DC system models.

Dynamics for conventional AC systems are usually represented by generator dynamics and many well-developed bench-mark models exist. Depending on the purpose of study and the time frame of interest, generator controls for voltage or turbine power can be modelled. On the other hand, generalized dynamic DC system models are also proposed [28, 29]. These mainly include the converter plant models and their hierarchical control structures, the DC circuit equations and the AC/DC coupling equations. However, integrated AC/DC models for power system stability studies in past literature are often based on either simplified AC systems [27] or simplified DC systems [30], with the assumption that the bandwidths of the DC system’s components are normally much higher than the AC system dynamics. It is demonstrated in this study that, even though the time frame of the controllers in the AC or DC side of the system is different, they can still have significant impact on each other. To develop a method for integrating detailed AC and DC system dynamic models is thus necessary and further studies are required in this direction.

VSC HVDC and AC Interactions

With integrated AC/DC system models, interactions between AC and DC systems can occur in many ways. Some of these potential interactions will be addressed in this research.
Power Oscillation Damping (POD)

Both VSC HVDC and FACTS can interact with the connected AC system through active power control. A potential benefit that results is the capability of providing POD for the connected AC system [31-36] to improve its electromechanical transient behaviour (see Appendix A1 for background of power system electromechanical oscillations). Conventional LCC based HVDC can only provide active power modulation. This is improved by VSC HVDC where both active and reactive power can be modulated independently by different POD controllers. Various control algorithms have been proposed to add POD controllers into the VSC HVDC controller through supplementary modulation to contribute in damping of the inter-area oscillations in the power system. More effective damping might be achieved through wide-area monitoring system (WAMS) based stabilizing control, because remote signals which contain more effective information of the modes of interest can be utilized as the input to the POD controller [33-35]. Superior to conventional local POD controllers, multiple signals can be employed by centralized or decentralized controllers to further improve damping performance of the overall system. However, the robustness of WAMS-based damping control needs to be carefully evaluated against potential loss of communication. In addition, time delay in a wide-area system would be inevitable and may have a detrimental impact on system stability, and it therefore needs to be carefully considered in POD control design. Typical types of POD controller for VSC HVDC are presented in Fig. 1.8.

![Fig. 1.8 Typical POD controllers for VSC HVDC with (a) local or (b) WAMS based signals.](image-url)
However, except for the auxiliary damping controls, the various typical outer controls in the VSC HVDC can also have effects on the electromechanical behaviour of the connected AC system. These effects have not been systematically analysed and opportunities therefore exist for further research to provide recommendations regarding VSC controller designs.

**AC Grid Frequency Support**

Main grid frequency support is another important subject regarding active power interaction between VSC HVDC and the AC system. The recent trend of replacing conventional generation (e.g. fossil coal) by offshore windfarm generation and inter-connectors will reduce the total inertia of the AC system. This makes the AC grid vulnerable to a short term power imbalance which arises from sudden changes of loads and/or generations, leading to more severe frequency fluctuations. Power system frequency recovery response can be categorized into several stages as shown in Fig. 1.9. When power mismatch occurs, the first stage inertial frequency response is mainly provided by the kinetic energy stored in the rotating mass of synchronous generator (few seconds). Then in the second stage, turbine governing control systems (GOV) and automatic generation controls (AGC) come into play for recovering system frequency. This can take up to several minutes. In situations where the system frequency continues to deviate (e.g. lower than 48.8Hz), low frequency relays will be triggered [37].

![Fig. 1.9 Frequency control philosophy of Great Britain (GB) system modified from [37].](image)

VSC HVDC can contribute to the first and second stages of system frequency control with its fast power control capability [38]. To enable such function, an initial solution using synthetic inertia control based on the rate of change of frequency (ROCOF) was discussed in [39]. For windfarm connections via VSC HVDC, it has been proposed that
the DC link voltage or wind turbine power can in certain circumstances be adjusted based on main grid frequency variations as proposed in [40] and [41] respectively. An inertia emulation control strategy was proposed in [42] to make use of the energy stored in the DC capacitors of the HVDC link, though large DC link capacitance was assumed. However, these methods have weaknesses in practice and further work with increased fidelity is required to explore the reliability of the controls in the VSC HVDC for providing frequency responses.

**Power System Voltage Stability**

Grid connected VSCs can also interact with the system through reactive power or AC voltage controls. One important issue with power systems is the voltage stability, which is defined as the ability to maintain acceptable voltages under normal conditions and when subjected to contingencies. It is suggested in [43] that by varying the control strategies employed in the VSC HVDC systems, it is possible to increase the maximum loadability of an AC system. Grid connected VSCs can be configured as a STATCOM (AC voltage control mode), which has been studied to be able to enhance the system static voltage stability margin [44]. Such capability can be demonstrated by plotting the PV curves of the system under different conditions. An example is shown in Fig. 1.10.

![Fig. 1.10 Typical PV curve plot.](image)

**Control Interactions between VSC and FACTS**

With the increasing amount of applications of power electronic based devices in today’s power system such as FACTS devices, further investigations consider the potential
interactions between VSC HVDC and these devices. At this stage there is still a great deal of uncertainty regarding the structure of future AC/DC systems. Studies have shown that there exist potential interactions between conventional LCC based HVDC and FACTS devices or multiple FACTS devices operating in the same system. The potential interactions between VSC HVDC systems – with their various control strategies – and FACTS devices have not been addressed before, and therefore further work is required in this field.

Analysis Techniques
The components in the AC and DC sides of the system form the non-linear power system model based on their differential and algebraic equations. To study this, different power system analysis techniques are used.

Modal analysis is one efficient tool which is most widely used for large system small signal stability studies. The system is linearized at a pre-defined operating point and modal analysis allows many tasks to be performed such as determining the modes of oscillations and the sensitivity of the system to changes in parameters. Modal analysis also helps to find the root loci for a transfer function and perform model reduction of a large system. The key point of modal analysis is the location of critical eigenvalues and eigenvectors of the system which is obtained by solving the following equation:

\[(A - \lambda I)\Phi = 0\] (1.1)

where \(A\) is the linearized system state matrix, \(\lambda\) is the eigenvalues and \(\Phi\) is the right eigenvector. Different algorithms are proposed to locate the eigenvalues of linearized system models including the commonly used QR method, the modified Arnoldi method which utilizes the sparse nature of the power system matrix method, and other techniques summarized in [20]. Techniques such as mode shape, participation factors and transfer function residues are used in this research for analysis where needed. Detailed modal analysis basics are given in Appendix A2.

Frequency domain analysis mainly includes classical frequency domain control theories such as transfer functions and bode plots. Such control theories are used to determine the stability of derived single-input single-output (SISO) closed-loop systems. When
dealing with multi-input multi-output (MIMO) systems, which can be decoupled, methods such as relative gain array (RGA) are used for designing and analysing. These theories are very well documented in book [45].

**Summary of Past Research on AC/DC Interaction**

Several gaps in the field have been identified that require further investigation:

i. Studies to date have provided dynamic mathematical models for both AC and DC systems. However, when integrated AC/DC system models are considered, simplifications are usually made for either the AC or DC side of the system. For the potential control interactions to be fully captured, the mathematical integration of detailed AC/DC dynamic models needs to be developed. Meanwhile, in order to increase the fidelity and accuracy of this study, a more realistic AC system model is required.

ii. The effect of VSC HVDC on AC system electromechanical behaviour has been analysed in many literature works with the focus being put on the supplementary power oscillation damping controllers. This research identifies that the typical outer controls of VSC HVDC can also affect the AC system electromechanical behaviour substantially, and the effect of these control schemes have not been systematically compared. It is therefore essential to provide an assessment of the effects of VSC controls on the AC system dynamics.

iii. Potential interactions are identified between conventional LCC HVDC and FACTS devices. No studies concerning the possible interactions between VSC HVDC and FACTS are available. Thus further investigation is required in this field.

iv. A detailed and comprehensive analysis of the capability of VSC HVDC for providing active power support to the connected AC system is currently lacking. Appropriate controls schemes which enable VSC HVDC for main grid active power support need to be designed and implemented in large power systems to assess their effectiveness.
Chapter 1. Introduction and Review of AC/DC Interaction

1.3. Project Background

Offshore windfarm connections in the UK, especially from larger Round 3 windfarm projects, are setting a number of HVDC transmission challenges. On an immediate level, the interconnection of windfarms along the coast of Great Britain requires further study. In the longer term, interconnection to other countries will become much more prevalent in the UK. These challenges will result in new DC interconnections, both to reinforce existing links and to make new ones to link to new generation and other networks. These substantial engineering problems require people who are skilled in both conventional power systems and the new DC transmission systems.

This PhD research is a 3.5-year project as a part of the National Grid DC Voltage Research Programme which is fully funded by National Grid, UK. It is closely linked to two other PhDs’ work in the University of Manchester, as shown in the following table, to address an integrated AC/DC transmission future.

<table>
<thead>
<tr>
<th>Projects</th>
<th>Subjects</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Control, Dynamics and Operation of Multi-terminal VSC HVDC Transmission Systems</td>
</tr>
<tr>
<td>2a</td>
<td>Control Interactions between VSC HVDC and AC System (slow electromechanical transients)</td>
</tr>
<tr>
<td>2b</td>
<td>Control Interactions between VSC HVDC and AC System (fast electro-magnetic transients)</td>
</tr>
</tbody>
</table>

This work is referred to as project 2a and will focus primarily on electromechanical transient processes and control aspects of AC/DC networks. This includes investigations on the integration of AC/DC system models and the effect of DC controls on the connected AC systems, as well as control strategies to coordinate both the DC terminals and AC system operation. The modelling work is performed in DIgSILENT PowerFactory with Matlab for analysis where needed. Internal deliverables are scheduled for National Grid regarding the progress and outcomes of this research.
1.4. Aims and Objectives

The aims of the thesis are in accordance with the project supported by National Grid which is mainly focused on addressing the issues raised from the past research of AC/DC interactions, and targeted at electromechanical transient processes and control aspects of AC/DC systems. A summary of the objectives are listed as follows:

i. Scoping study and development of operational scenarios – Investigate a range of probable future scenarios in UK with different levels of penetration of VSC HVDC and FACTS technology, and identify the key dynamics and fidelity of the models required.

ii. Development of generic AC/DC models – develop generalized dynamic models for both AC and VSC HVDC systems. Provide mathematical integration of the dynamic AC/DC models.

iii. Development of a dynamic GB system model – develop a representative dynamic Great Britain (GB) system model based on realistic reference load flow data to increase the fidelity of the study.

iv. Assessment of VSC controls – perform more thorough robustness and sensitivity studies to compare the effect of VSC controls on integrated AC/DC system electromechanical dynamics. Provide recommendations for the designs of VSC controls and their parameterizations.

v. Identification of potential control interactions – analyse potential interactions between VSC HVDC and FACTS devices considering different system conditions.

vi. Additional control requirements for VSC HVDC in probable scenarios – develop control strategies for VSC HVDC to enable its capability of providing active power support for the main grid to improve AC system stability.

1.5. Thesis Main Contributions and Publications

The research carried out in this thesis has contributed to a number of areas regarding the control and stability of integrated AC/DC systems. The main outcome of this research is
the systematic assessment of the effects of integrating VSC HVDC technology on the conventional AC system. Some associated work is provided in the form of conference [C] and journal [J] publications – which are given in Appendix E – and a set of internal reports for National Grid. The main contributions of this thesis can be briefly summarized as:

i. A scoping study is performed to investigate a range of probable future AC/DC scenarios which gives a view of possible future electricity transmission options for the GB grid [associated work: Internal Report “VSC HVDC Candidate Scenarios” for National Grid].

ii. An overview of the study AC/DC interactions to date is provided which includes issues with power oscillation damping, AC grid frequency support, etc. [associated work: Internal Report “An Overview: Power Oscillation Damping with VSC HVDC” for National Grid].

iii. A generic method is proposed to integrate VSC terminals into AC systems. A generic dynamic AC/DC model is developed based on the proposed mathematical integration method for small signal stability studies [C5].

iv. A dynamic representative GB system model is developed based on the reference steady stage load flow data [associated work: Internal Report “Design of Reduced Dynamic Model of GB Network and Integration of VSC HVDC Lines” for National Grid].

v. The problems to integrate an offshore windfarm via VSC based HVDC systems into an AC network are identified. The operation principles of the proposed system are described with the focus being put on the interactions of the control strategies used in the AC network generators and the DC terminal converters [C1].

vi. The potential control interactions between STATCOM and VSC HVDC operating in the same AC system are identified and analysed [C2], [C4].

vii. An Investigation of a multi-machine AC system model integrating a four-terminal VSC HVDC system is performed. The effect of different MTDC control schemes
including voltage margin control and different droop control settings are compared [C3].

viii. The effect of VSC HVDC outer controls on the AC system electromechanical oscillations and DC system dynamics is analysed in a systematic way in order to provide recommendations for VSC outer control selections and parameterizations [J1].

ix. A frequency based droop setting is proposed and implemented to enable VSC HVDC links to provide power support for improving AC system stability during power imbalance situations [associated work: Internal Report “Additional Control Requirements for VSC HVDC - A Specific Case Study” for National Grid].

1.6. Thesis Outline

There are seven chapters in this thesis. The outline of the remaining chapters is provided below:

Chapter 2 details the modelling of the key components on both the AC and DC sides of the system and proposes a mathematical integration method for dynamic AC/DC models.

Chapter 3 shows the development of a more specific dynamic GB system model with greater fidelity. The detailed design procedures from a steady-state model to a dynamic model are presented.

Chapter 4 investigates the effect of VSC outer controls on the integrated AC/DC system electromechanical behaviours based on the developed models in the previous chapters. The focus is put on the stability of AC system inter-area oscillation and DC system transient responses.

Chapter 5 extends the study of interactions from VSC/AC to VSC/FACTS. Potential control interactions between VSC HVDC and STATCOM are identified and analysed.

Chapter 6 identifies additional control requirements for VSC HVDC in probable scenarios. A frequency based active power control scheme is proposed and implemented to improve AC system stability.

Chapter 7 summarizes the thesis and provides suggestions for future work.
Chapter 2. AC/DC Models, Controls and Integration

The power industry today sees an ever increasing number of voltage source converter based high voltage direct current (VSC HVDC) projects being put into operation with the conventional AC system. The development of a multi-terminal DC (MTDC) grid will bring significant influence to the operation of AC power systems. Therefore, incorporation of VSC HVDC transmission into existing AC transmission networks has become a main challenge. For power system stability studies, integrated AC/DC system models with appropriate level of fidelity to capture key system dynamics are thus required. This chapter details the mathematical models of the key components for developing typical AC and DC systems, together with their various control strategies. A method is proposed for combining the mathematical models to form an integrated AC/DC system targeted at electromechanical transient studies. To demonstrate the integration method, a test AC/DC system is developed.

2.1. Modelling of AC System

Synchronous Generators
One of the key fundamental components in an AC system model is the generators. The correct modelling of synchronous generators is a very important issue in the studies carried out for electrical power systems. The type and accuracy of the generator models can have great influence on the results of power system simulations. Lower order generator models are likely to result in a lack of accurate description of practical operation states. Therefore in order to capture the transient
dynamics in the system, higher order detailed generator models are normally adopted.

The main circuits involved in a synchronous machine are shown in Fig. 2.1 where $\theta$ represents the angle by which the rotor d-axis leads the phase a stator winding. The electrical performance of a synchronous generator can be developed based on the dynamic equations of the coupled circuits in Fig. 2.1 [20]. Usually, a simpler form of the dynamic equations, to more clearly show the physical picture of the machine, is obtained through a dq0 transformation. The transformation process can be viewed as a means of referring the stator quantities to the rotor side, based on angle $\theta$. This allows inductances to have constant values in the dynamic performance equations, and the transformed stator quantities to have constant values under balanced steady-state conditions.

Based on the equivalent circuits of a synchronous machine, the characteristic states of a generator are defined as the steady-state, the transient state and the sub-transient state. Machine parameters that influence rapidly decaying components are called the sub-transient parameters, while those influencing the slowly decaying components are called the transient parameters and those influencing sustained components are the synchronous parameters. Generators can be represented by an emf behind a reactance in each of the three states. To allow the dynamics of the synchronous
generator to be fully expressed, the conventional sixth order generator model is used for the studies in this thesis, and it is summarized via the set of equations provided in Appendix C1.

It should be noted that the mathematical synchronous generator equations do not consider the effects of stator and rotor iron saturation in order to make the analysis simple and manageable. However, in cases where generator saturation is of concern, a representation of the saturation for stability studies is provided for generator models in DIgSILENT PowerFactory. The parameterization method is detailed in Appendix C2.

**Generator Control**

The control systems of generators play a vital role in maintaining power system stability, and therefore need to be included in the generator models. A general control structure is presented in Fig. 2.2. The generator connected buses are PV type buses where the generators interact with the AC system network by injecting power and controlling the bus voltage. The AC network equations will then be solved to give the generator currents back.

![Generator model and control for stability study.](image)

The terminal voltage is controlled by means of excitation system through field current control. This is provided by automatic voltage regulator (AVR) which is performed through excitation control and acts on the DC voltage that supplies the excitation winding of a synchronous generator. The variation of the resulting field current changes the generator emf to control generator output voltage. A voltage transducer that senses, rectifies and filters the terminal voltage to a DC quantity is
also required for comparing the output voltage to the reference. Meanwhile, a power system stabilizer (PSS) may be included in the excitation system, with either rotor speed, accelerating power or frequency as the input signal. PSS provides auxiliary stabilizing signals to the reference excitation voltage which helps to damp the generator rotor oscillations in order to improve power system dynamic performance. Additionally, prime mover governing systems allow generators to modify their mechanical power input to perform generator speed control. The turbine model may be included when system frequency is a subject of study. However, for studies that focus on electromechanical transients (a few to tens of seconds), the turbine power can be considered as constant during such short periods, allowing the generator control system model to be simplified.

Branches
AC system branches with voltage difference at the two ends can be modelled as transformer branches; otherwise, it is a transmission line branch. A simplified transformer model is used, neglecting magnetizing current and no-load losses. The model is an ideal transformer with adjustable turns ratio and series impedance that represents resistive losses and the leakage reactance. The transformer can be configured as in-phase or phase-shifting depending on the turns ratio configurations. The AC system’s transmission line model used in this study is the common π circuit model with lumped parameters [20]. In a balanced system condition, the transmission lines are normally defined by series impedance and shunt admittance. The effect of shunt conductance $G_{ij}$ is usually small enough to be neglected in power system lines. A π circuit line model between bus $i$ and $j$ can be expressed as:

\[
Z_{ij} = R_{ij} + jX_{ij} \quad \text{(series impedance)} \quad (2.1)
\]

\[
Y_{ij} = G_{ij} + jB_{ij} \quad \text{(shunt admittance)} \quad (2.2)
\]

However, it is possible to combine the branch models into a unified complex model [46] which can be used for lines, transformers, and phase-shifters. This unified model is illustrated in Fig. 2.3.
Different parameter settings in the unified model will enable representations for transmission lines or transformers (e.g. when $T_{ij}=T_{ji}=1$, the model becomes an equivalent π circuit for transmission lines). Alternatively, when shunt elements are neglected and $T_{ij}=1$, the model becomes a transformer model with the tap changer located at bus $j$ side and turns ratio $T_{ji} : 1$. The general current equations of such a unified model are given as:

$$I_{ij} = (a_y^2 E_i - T_{ij}^* T_{ji} E_j) y_{ij} + Y_{ij} a_y^2 E_i$$
$$I_{ji} = (a_y^2 E_j - T_{ji}^* T_{ij} E_i) y_{ij} + Y_{ij} a_y^2 E_j$$

(2.3)

where

$$E_i = T_{ij} a_y e^{j\phi_i} \quad \frac{E_i}{E_i} = T_{ji} = a_y e^{j\phi_i}$$

$$E_j = T_{ji} a_y e^{j\phi_j} \quad \frac{E_j}{E_j} = T_{ij} = a_y e^{j\phi_j}$$

(2.4)

Such level of fidelity of the branches is applicable for general power system stability analysis carried out in this thesis. A complex transmission line model may be considered for more detailed studies, when factors like unbalanced system situations and harmonics are taken into consideration.

**Loads**

Power system load models are mathematical representations of the relationship between a bus voltage and the power/current (active and reactive) flowing into the bus. The load models are generally classified as static or dynamic load models. The
former is preferred for power system transient stability analysis. Static load models express the active and reactive power at any instant of time as functions of the bus voltage magnitude and frequency at the same instant. Dynamic load models further includes past instants, voltage-power relationships and the dynamics of different load types (e.g. motors, protective relays, etc.).

Static load models can be further categorized into three types as shown in Table 2.1 with the corresponding exponential expressions of the three models. \( P_0 \) and \( V_0 \) are the initial load power and load bus voltage. \( P \) and \( V \) are the load power and load bus voltage that vary with time.

<table>
<thead>
<tr>
<th>Static Load Models</th>
<th>Description</th>
<th>Exponential load models</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant impedance (Z)</td>
<td>Power varies directly with the square of the voltage magnitude</td>
<td>( P = P_0\left(\frac{V}{V_0}\right)^2 ) ( Q = Q_0\left(\frac{V}{V_0}\right)^2 )</td>
</tr>
<tr>
<td>Constant current (I)</td>
<td>Power varies directly with the voltage magnitude</td>
<td>( P = P_0\left(\frac{V}{V_0}\right)^4 ) ( Q = Q_0\left(\frac{V}{V_0}\right)^4 )</td>
</tr>
<tr>
<td>Constant power (P)</td>
<td>Power does not vary with changes in voltage magnitude</td>
<td>( P = P_0 ) ( Q = Q_0 )</td>
</tr>
</tbody>
</table>

Alternatively, a combination of static load characteristics in Table 2.1 can be readily expressed in the form of a ZIP model [47]:

\[
P = P_0\left[a_1\left(\frac{V}{V_0}\right)^2 + a_2\left(\frac{V}{V_0}\right) + a_3\right]
\]  
\[
Q = Q_0\left[a_4\left(\frac{V}{V_0}\right)^2 + a_5\left(\frac{V}{V_0}\right) + a_6\right]
\]

where coefficients \( a_{(1-6)} \) can be varied to define the proportion of each type of static load and thus achieve a combination of different static load models. Frequency dependent load characteristics can be configured by multiplying the above expressions by a factor related to the frequency deviation, but this is not considered for this case.

For general load models in large power systems, in absence of detailed information on the load composition, the most commonly accepted static load model is to represent active power with a constant current and reactive power with constant
impedance. The constant current active power represents a mix of resistive and motor devices (nearly constant MVA). This representation may be shifted towards constant impedance or constant MVA, if the load is known to be more resistive or more motor driven respectively.

Network Modelling
A power system network can be converted into an equivalent impedance matrix that includes the line and transformer branches. This matrix forms the basic network voltage and current equations. An example equation is shown as:

\[
\begin{bmatrix}
I_1 \\
I_2 \\
\vdots \\
I_n \\
\end{bmatrix} = \begin{bmatrix}
Y_{11} & Y_{12} & \cdots & Y_{1n} \\
Y_{21} & Y_{22} & \cdots & Y_{2n} \\
\vdots & \vdots & \ddots & \vdots \\
Y_{n1} & Y_{n2} & \cdots & Y_{nn} \\
\end{bmatrix} \begin{bmatrix}
V_1 \\
V_2 \\
\vdots \\
V_n \\
\end{bmatrix}
\]

(2.7)

where subscripts are bus numbers, such that \( Y_{nn} \) is the self-admittance of bus \( n \) and \( Y_{ij} \) is the mutual-admittance between buses \( i \) and \( j \).

To simplify the three-phase AC network calculation, the network is modelled in the dq domain based on the dq0 transformation. Models for synchronous machines and voltage source converters can be added into the network model with their own local dq reference frame. This requires a conversion between different dq reference frames, as shown in Fig. 2.4.

![Fig. 2.4 System with different dq reference frames.](image)

Conversion from one dq domain reference frame (D-Q) to another (d-q) takes the form:

\[
\begin{bmatrix}
v_d \\
v_q \\
\end{bmatrix} = \begin{bmatrix}
\cos \sigma & \sin \sigma \\
-\sin \sigma & \cos \sigma \\
\end{bmatrix} \begin{bmatrix}
v_D \\
v_Q \\
\end{bmatrix}
\]

(2.8)
where $\sigma$ is the angle difference between different frames. Detailed explanation of dq0 transformation and the derivation of the conversion between different dq reference frames is provided in Appendix C3.

**Test System for Generic AC/DC Interaction Study**

Based on the mathematical representations derived previously for the key AC components, a generic test system model can be introduced for power system small disturbance stability studies, as presented in Fig. 2.5. The model is a small four-generator, two-area system with detailed system parameters given in [20]. In this case, generators are modelled as sixth order and employ a typical thyristor excitation system for voltage control and a PSS for damping. Roughly 400MW power is transferred from Area 1 to Area 2 through two weak AC tie-lines.

Applying modal analysis for the developed power system results in three electromechanical oscillatory modes: two oscillatory local modes indicating generators in each area are oscillating against each other and one inter-area mode of frequency of about 0.5Hz and a damping ratio less than 5% suggesting that generators in Area 1 are oscillating against generators in Area 2.

![Two-area AC System Model](image)

Fig. 2.5 Kundur’s two-area system model (upper) and thyristor excitation system with PSS (lower) modified from [20].
2.2. Modelling of VSC HVDC

VSC HVDC is considered as a suitable solution for connecting large offshore windfarms that are sited far from the onshore AC grid. The VSC converter topology design has evolved through many generations and its control strategy is now well developed. In comparison with conventional line commutated converter (LCC) HVDC, it has the advantages of a smaller foot print, black start capability, independent real and reactive power control, and a significantly lower harmonic level if a modular multi-level converter (MMC) topology is used. In this section, the mathematical models of VSC HVDC and its control systems are addressed.

![Diagram of multi-terminal VSC HVDC control system](image)

The control system for VSCs has a cascaded structure as depicted in Fig. 2.6, with each higher level of control being no faster than its next inner control level. The typical controls in each level are also listed in Fig. 2.6. For a wholly decoupled operation, it is normally appropriate that higher level controls are at least four times slower than the next inner level [48]. The type of switching control employed for the innermost voltage conversion process depends largely on the topology of the converter, with its voltage orders provided by inner current controls in the converter control level. There are normally several types of typical VSC outer controls being
equipped in a converter station providing different functions (e.g. power and voltage control). They are switchable depending on the actual applications. The outer controls reference points may be obtained from local or global higher level control signals. For instance, a system level “DC grid master control” is a high level control for coordinating the DC voltages and DC power dispatches. This level of control often has low bandwidth and is employed to achieve optimised DC grid operation. Telecommunication systems may be required for future large DC grid in order to monitor the system’s operating conditions and to schedule new power/voltage orders for the DC grid. Estimated bandwidths for each level of control are provided in Table 2.2. As the bandwidths of converter level controls are most relevant to the power system electromechanical transient behaviours, detailed descriptions and analysis will be carried out for the controls in this level at later stages.

Table 2.2 Estimated control loop bandwidths and limitations.

<table>
<thead>
<tr>
<th>Cascaded Structure</th>
<th>Bandwidth [48, 49]</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Valve switching control (voltage conversion)</td>
<td>1kHz to 20kHz</td>
<td>Converter switching frequency (e.g. ABB HVDC Light OPWM 1050Hz; Siemens MMC 20kHz in effect)</td>
</tr>
<tr>
<td>Converter level inner current control</td>
<td>10Hz to a few hundreds of Hz</td>
<td>- Inner voltage conversion process</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Line current measuring speed</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Filtering of line frequency harmonics</td>
</tr>
<tr>
<td>Converter level outer control</td>
<td>1Hz to tens of Hz</td>
<td>-Inner current loop</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-Speed of measuring actual quantities</td>
</tr>
<tr>
<td>System level control</td>
<td>0.1Hz to less than 1Hz</td>
<td>-Inner power loop</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-Coordination software limits</td>
</tr>
</tbody>
</table>

Converter Voltage Conversion and Converter Equations

The Inner voltage conversion process is determined by the converter topology and its switching control. In fact this is how the AC voltage is synthesized from the DC

---

1The bandwidths are estimated according to data provided in the reference provided. Some controller parameters are also available in the provided references for converters at the windfarm side and the AC grid side.
voltage. This is the innermost basic control loop that is contained in all the other control loops. In comparison with sine-triangle pulse-width modulation (PWM) converters, more complex control will be required for MMC converters to ensure voltage balancing between levels. Taking the sine-triangle PWM converters as an example, the DC line voltage is usually measured and then fed into the converter to make a robust and controlled AC output. This can be averaged over one PWM switching frequency cycle as:

\[ V_{ac\_peak} = \frac{1}{2} P_M V_{dc} \]  

(2.9)

where \( P_M \) is the modulation index, which is the ratio between the peak value of the modulating wave and the peak value of the carrier wave.

For power system electromechanical transient studies with VSC HVDC systems, detailed converter switching processes and the associated dynamics are not key contributions to the key dynamic behaviour of the overall integrated system. The computational burden that would be introduced by detailed modelling would complicate the study of transients – particularly when integrated into large AC networks – and this would also significantly increase the simulation time.

It has been previously validated in [12] that the averaged-value model can accurately replicate the dynamic performance of the detailed model for studies of these transient phenomena. Also, as the number of levels increase in converters like MMC, the AC side voltage waveforms become more sinusoidal. Therefore, the converter modelled in this study is a fundamental frequency representation, which is equivalent to an ideal controlled voltage source (in essence what the MMC is attempting to reproduce). A capacitor is used to represent a capacitance equivalent to the detailed MMC model. This is considered as a more than adequate representation of the MMC type converters for large AC/DC system RMS level stability studies, so the focus can be put on the outer control loops. The detailed MMC EMT transients are fast enough to be neglected, and thus the converter topology is not a significant issue for simulations of integrated AC/DC systems.
From a system point of view, the equations to describe a VSC can be derived based on Fig. 2.7. The voltage and current relationship across the phase reactor can be expressed as:

\[ e_{abc} - v_{abc} = L \frac{di_{abc}}{dt} + Ri_{abc} \]  \hspace{1cm} (2.10)

Applying the dq transformation (see Appendix C3):

\[
\begin{pmatrix}
    e_d \\
    e_q
\end{pmatrix} =
\begin{pmatrix}
    R & -\omega L \\
    \omega L & R
\end{pmatrix}
\begin{pmatrix}
    i_d \\
    i_q
\end{pmatrix} +
\begin{pmatrix}
    L & 0 \\
    0 & L
\end{pmatrix}
\begin{pmatrix}
    i_d \\
    i_q
\end{pmatrix}
\]  \hspace{1cm} (2.11)

For a balanced system and a power invariant transformation (i.e. \( k=\sqrt{\frac{2}{3}} \) in the Clarke transformation), the relationship between the real and reactive power at the point of common coupling (PCC) bus and the dq domain voltages and currents can then be written as:

\[ P_e = v_d i_d + v_q i_q \]

\[ Q_e = v_d i_q - v_q i_d \]  \hspace{1cm} (2.12)

Neglecting the losses in the converter, the power injected by the converter into the AC network is equal to the DC link power, and the DC voltage dynamics are given by the DC side capacitor. The equations are:

\[ C_{eq} \frac{dV_{dc}}{dt} = i_n + i_{dc} \quad \text{and} \quad i_n V_{dc} = e_d i_d + e_q i_q \]

Combining gives:

\[ \dot{V}_{dc} = -\left( \frac{e_d i_d + e_q i_q}{C_{eq} V_{dc}} \right) + \frac{i_{dc}}{C_{eq}} \]  \hspace{1cm} (2.13)
The equations of phase reactors together with the equations of the DC capacitor give the key dynamics of a converter. After dq transformation and linearization, the converter’s dynamic equations are summarized as follows:

\[
\begin{pmatrix}
\frac{d\Delta i_d}{dt} \\
\frac{d\Delta i_q}{dt} \\
\frac{d\Delta V_{dc}}{dt}
\end{pmatrix} =
\begin{pmatrix}
-\frac{R}{L} & \omega & 0 \\
-\omega & -\frac{R}{L} & 0 \\
-\frac{e_d}{C_{eq}V_{dc}} & -\frac{e_q}{C_{eq}V_{dc}} & (e_d \Delta i_d + e_q \Delta i_q)
\end{pmatrix}
\begin{pmatrix}
\Delta i_d \\
\Delta i_q \\
\Delta V_{dc}
\end{pmatrix} +
\begin{pmatrix}
1/L & 0 & -1/L & 0 & 0 \\
0 & 1/L & 0 & -1/L & 0 \\
-\frac{i_d}{C_{eq}V_{dc}} & -\frac{i_q}{C_{eq}V_{dc}} & 0 & 0 & 1/C_{eq}
\end{pmatrix}
\begin{pmatrix}
\Delta e_d \\
\Delta e_q \\
\Delta v_d \\
\Delta v_q
\end{pmatrix}
\]

(2.14)

where \(i_d\), \(i_q\), \(V_{dc}\) are the key state variables that describe the behaviour of a converter seen from a system point of view.

**Converter Level: Direct Control and Vector Current Control**

Several types of control methods have been proposed for VSC HVDC based on the innermost voltage control loop. Among them, power-angle control (direct control), which used to be employed in STATCOM applications [50], and dq current control (vector control) [51] are most investigated.

![Power Angle Model](image)

**Fig. 2.8 Power-angle model.**

The principle of direct control is to manipulate the magnitude of the converter output voltage and the phase angle between the VSC and the AC systems. The plant model for direct control is firstly derived. This is illustrated in Fig. 2.8, which is a power angle model with complex impedance \(Z\). The power is calculated as:

\[
P_E = \text{Re}(S_E) = \frac{E^2 \cos \gamma - EV \cos(\alpha + \gamma - \beta)}{Z}
\]

(2.15)

\[
Q_E = \text{Im}(S_E) = \frac{jE^2 \sin \gamma - EV \sin(\alpha + \gamma - \beta)}{Z}
\]

(2.16)
When terminal \( V \) is considered as an infinite source (\( \beta=0 \)) and impedance \( Z \) is considered as lossless (\( \gamma = 90^\circ \)), the equation is simplified as:

\[
P_E = \frac{EV \sin \alpha}{X}
\]

\[
Q_E = j \frac{E^2 - EV \cos \alpha}{X}
\]

where \( \alpha \) is now the phase difference between bus voltages \( E \) and \( V \).

The phase angle and output voltage magnitude can be controlled directly or by feedback type controls as depicted in Fig. 2.9 (a) and (b). The converter AC side voltage is controlled through the modulation index based on equation (2.9). When a VSC is connected to a very weak AC network such as a windfarm, it acts as the source which sets voltage and frequency. This forms a special sub-case of direct control since the wind turbines in effect control their angles and voltages with respect to the VSC HVDC system.

![Diagram](figure)

Fig. 2.9 (a) Direct voltage control, (b) Feedback type power angle control.

The phase angle is controlled by adjusting the phase shift of the converter AC side voltage with reference to the output of a phase locked loop (PLL), which is normally synchronized to PCC bus voltage. This determines the active power flowing into the VSC, and hence charges and discharges the DC capacitor to maintain a constant DC voltage. However, due to the cross-coupling between the control parameters, the power-angle control technique is unable to provide independent control of
active/reactive power. Additionally, due to the lack of a current control loop, direct control does not provide the capability to limit the current flowing into the converter. This is part of the reason why another type of control – vector current based control, which limits the current flowing to some extent – is used in some cases.

Vector control (Fig. 2.10) is a current control based technique, and thus it can limit the current flowing into the converter. It is also known as “dq current control”. The control is established by converting the voltages and currents into the dq domain. For a balanced steady-state operation, the dq voltages and currents are mostly DC values and thus are easy to control. In case of an unbalanced operation, the positive and negative components of the AC system have to be considered in the control system. This requires different controllers for each sequence and a method to separate them.

![Fig. 2.10 Closed-loop block diagram of dq current control.](image)

**PLL**

\[ v \sin(\theta - \theta') = v \sin \theta \cos \theta' - v \cos \theta \sin \theta' \]

![Fig. 2.11 Phase-locked loop.](image)
Typically, the balanced three-phase AC voltage is taken at the point between the converter and the network, as shown in Fig. 2.10. The dq current orders are given by outer controllers, and the two current loops are decoupled by using the nulling terms $\omega Li_{dq}$ to reduce the cross-coupling effect. Ideal nulling might not be necessary as small residual coupling can be acceptable. The plant model for the current control is given by equation (2.11); and if PI type current controllers are used, the current control can be expressed using the following equations:

$$
e^* \alpha = (k_{pa} + \frac{k_w}{s})(i^\alpha - i_d) - \omega Li_q + v_d$$

$$
e^* \beta = (k_{pq} + \frac{k_w}{s})(i^\beta - i_q) + \omega Li_d + v_q$$

A PLL [51, 52] on the positive sequence fundamental voltage component of the network voltage is required for the dq transformation to obtain the reference angle. A typical structure is shown in Fig. 2.11, which reduces the voltage q-axis component to zero in order to align the reference frame with the d-axis. Normally, a fast dynamic response and a high bandwidth controller are required. However, there is always a trade-off between the transient response level and a fast bandwidth.

For current loop controller design, the dq current loop transfer function can be approximated to a second order equation using the plant model equation (2.11) and current control equation (2.19). By doing so, the desired damping ratio and natural frequency of the control loop can be calculated. Typically, this is done by assuming $k_i >> sk_p$ (in the frequency range of interest), and a standard form is like:

$$\frac{i}{i^*} = \frac{\omega_n^2}{s^2 + 2\omega_n \xi s + \omega_n^2} \approx \frac{k_i}{L} = \frac{s^2 + s(k_p + R) / L + k_i / L}{s^2 + s(k_p + R) / L}$$

However, the current control loop is limited by several factors:

i. The bandwidth, normally adjusted by tuning the current loop controller, should not be faster than the innermost voltage switching control. A bandwidth of at least 1/4 of the inner voltage conversion process is normally appropriate.
ii. The manipulated AC voltage input ($e_{dq}^*$) is limited by the range of the DC link voltage.

iii. Over-current limits are necessary for IGBTs in practice as the software current limits in the dq domain do not limit the current in real world (abc) quantities for unbalanced contingencies. Furthermore, as equation (2.10) is used to derive the dq current control, a precondition of the PLL to obtain an accurate synchronization to the AC system is assumed. This is not always true during AC system faults or in the case of weak AC systems. Some difficulties have been experienced by VSC HVDC based on vector-current control in weak AC system connections. Several advanced control strategies have been proposed to mitigate such problems with AC grid [53]. Investigations have shown that the PLL dynamics might have a negative impact on the performance of VSC HVDC in weak AC system connections. The PLL may also become inaccurate during fault conditions or unbalanced AC network situations and the vector control or feedforward outer power loops can be affected in such cases. Another significant factor which needs consideration in a fuller model is the degree to which the power converter can be overloaded. Power electronic semiconductors have low (negligible) thermal mass. Thus there is no ‘free’ short-term overload capability — any overload capability in current or voltage must be paid for. A comparison between the vector current control and direct control is given in [54].

**Converter Level: Outer Controls and Droop Characteristics**

Vector current control provides independent real and reactive power control via the dq transformation. Based upon this fast inner current loop, different outer power and voltage control strategies can be applied in various forms depending on the application (e.g. feedforward type and feedback type outer controls). Droop characteristics can also be added to provide adjustable reference set points for the outer control loops for multi-terminal operation. The block diagram representations are summarized in Fig. 2.12 where the cascaded converter control structure is shown. In this case, the converter (upper) level control is further divided into 3 parts.
**DC Voltage Feedback Loop**

Variations in the DC voltage indicate unbalanced power exchange between the AC and the DC systems. Thus the power balance in a DC system is kept through constant DC voltage control \([55, 56]\). Large variations in the DC link voltage are not acceptable as this might lead to power imbalance or device failure. Normally, there is at least one converter in the DC grid that takes the responsibility to maintain a constant DC voltage. This is achieved by adding an outer controller (PI) to modify the d-axis reference current input with the measured DC link voltage as a feedback. Limitations are necessary to avoid unacceptable values of reference current due to large variations in DC link voltage. As shown in Fig. 2.12, the DC voltage control can be expressed as:

\[
i_d^* = (k_p \cdot d + k_i \cdot \frac{1}{s})(V_{dc}^\ast - V_{dc})
\]  

(2.21)

In a point-to-point VSC HVDC scenario linking two onshore networks or a grid integration of offshore windfarms, the converter connecting to a stronger AC network is typically configured to regulate the DC voltage. This is because a strong
AC network is more reliable for providing a robust AC side voltage and absorbing DC grid power.

Real and Reactive Power Controls
Feedforward real and reactive power controls [57, 58] can be modelled using equation (2.12). They link the converter’s power response directly to the actual current in the dq domain. Instead of adding an additional PI controller to form a feedback real and reactive power loop, feedforward type controls contain less dynamics in theory and have faster responses to converter power variations. Since a perfect PLL performance is assumed in these controls, they are likely to be affected when PLL is inaccurate during faults or unbalanced conditions. Care must be taken though with feedforward control as the notional disturbance \( v_d \) is not part of an actual and significant feedback loop.

Feedback real and reactive power controls [59-62] are also used for controlling converter power to reference values. An additional power loop controller needs to be designed in these feedback type controls. Extra dynamics and complexity are introduced by the outer controller, and the bandwidth is reduced in comparison with the feedforward type power controls.

Feedback AC Voltage Control
AC voltage control [63, 64] is used to regulate the converter AC side voltage. This requires measuring the AC voltage at the point of connection, and it is preferred in situations where a grid connected VSC provides voltage support to improve the AC system stability. With this type of control, the VSCs contribute to mitigate disturbances in the AC network by supplying reactive power.

Voltage Margin Control
The constant DC voltage feedback control mentioned before is often applied to a converter to serve as a “DC slack bus” in the DC system. The power injection to the DC grid varies between the maximum and the minimum capability of the converter
to maintain a constant DC voltage. This characteristic can be illustrated by a $V_{dc}-P$ relationship in Fig. 2.13.

![Fig. 2.13 Constant DC voltage slack bus control.](image)

With the development of a DC grid, there will be more converter stations connected together in the same DC grid forming a MTDC grid. If there is only one converter to maintain the DC voltage for the whole DC grid, several constraints will appear. The DC slack converter needs to be sufficiently large in order to compensate the total power change in the DC grid. A high standard of stability and reliability is also required for this converter because its loss leads to the collapse of the whole DC grid. Therefore, as the size of the MTDC system increases, it is not safe to rely on only one converter to take the full responsibility of DC voltage regulation. The remedy method for this situation is to use the concept of voltage margin or voltage droop control.

Voltage margin control is clearly described in [65]. Principally, the voltage margin approach enables more converters in the DC grid to participate in DC voltage regulation. In voltage margin control, each converter controls its DC voltage as long as the power flow is within limits and the DC voltages of the terminals are offset from one another by a certain voltage margin (some typical examples are available in [65]). This voltage margin is introduced to avoid interaction between the DC voltage controllers in different terminals. A typical voltage margin control in a two-terminal HVDC link is presented in Fig. 2.14. In this case, the power is transferred from converter 2 to converter 1 and the intersection is the steady-state system
operating point. Converter 1 controls the DC voltage and converter 2 is operating at its lower limit to control power transfer. It should be noted that line voltage drop along the DC line is neglected in this example and the voltage margin is exaggerated for clarity.

![Diagram of voltage margin control]

Fig. 2.14 Example of voltage margin control.

In a MTDC system using voltage margin control, the role of DC voltage regulation can be transferred from one converter to another. This occurs when the voltage regulating converter reaches its power (or current) limit or fails. Examples of this operation are available in [66] and a recently commissioned MTDC project in China [10]. However, although the responsibility of DC voltage regulation is transferrable, voltage margin control is still restricted to allow only one converter to regulate the DC voltage at any instant. Loss of a DC voltage regulating converter will not collapse the whole system, but the problem of one converter taking the full responsibility for the whole DC grid voltage stability remains. Therefore, this type of control is mainly suitable for small scale DC grid connecting to relatively strong AC systems. With the development of DC transmission, droop type controls (see next section) may be more appropriate for large DC grids.

**Droop Type Controls**

The power or voltage references of the outer control loops can be properly adjusted according to different power flows or operation scenarios through a cascaded droop characteristic.
DC voltage droop control [56] has been proposed to resolve the problems encountered before with voltage margin control. This type of control is especially useful in multi-terminal DC grid operation as there can be more converters participating in DC voltage control simultaneously, and thus sharing the duty of maintaining DC voltage and power balancing. One of the key features of DC voltage droop control is that the DC voltage of each terminal can be varied within limits. A typical droop control characteristic is shown in Fig. 2.15.

![DC voltage droop control characteristic](image)

Fig. 2.15 $V_{dc}$-$P$ characteristic voltage droop control.

A proportional gain ($k_{slope}$) can be defined for the DC voltage droop control to set the allowable DC voltage variation for given power limitations. When the power injection or absorption reaches the limit, the converter turns into power limit mode. $V_{dc_{ref}}$ denotes the no-load reference voltage that should be carefully selected according to the operational requirements. Actual DC voltage $V_{dc}$ is measured during operation and fed back into the droop control to modify the power reference of the converter. Under this configuration, all converters equipped with DC voltage droop control response to the power variations in the DC grid. This can be added as a cascaded outer loop to the power loop as shown in Fig. 2.16. Other structures using droop characteristics between voltage and current ($I_{dc}$-$V_{dc}$) rather than $V_{dc}$-$P$ are also implemented as seen in [67-70].
However, in a real DC grid, there are always resistances in cables which results in different DC bus voltages when non-zero power flows through the system. A specific power flow operating condition is associated with a unique set of DC bus voltages. This can affect the precise power flow control in steady-state operation. In order to determine the reference DC voltage set points as well as power set points, a precise DC grid load flow needs to be carried out for a given load flow condition. A detailed analysis for this issue is available in [56].

There are also other droop characteristics that can be applied to grid connected converters to contribute to grid frequency and voltage support. Fig. 2.17 shows the characteristics of the grid side converter AC voltage and frequency droop control.

AC Voltage Droop Control in a grid connected VSC is analogous to the way a STATCOM or a static VAr compensator (SVC) adjusts their reactive power output based on local voltages. The VSC injects reactive power to the grid when the AC voltage drops, and it absorbs reactive power when the AC voltage rises too high
based on equation (2.22). In this configuration, the VSC helps to enhance the AC system voltage stability.

\[ Q - Q_{\text{ref}} = (V_{\text{ac,ref}} - V_{\text{ac}}) \left( \frac{1}{k_{\text{slope}}} \right) \]  

(2.22)

Frequency Droop Control is also a method of configuring the grid connected VSC to contribute to grid frequency support together with other AC system power sources such as synchronous generators and large induction motors. A power dependant frequency control approach [40] can be adopted. In this control mode, the VSC needs to coordinate with other frequency control sources in a system, and the equation is written as:

\[ P - P_{\text{ref}} = (f_{\text{ref}} - f) \left( \frac{1}{k_{\text{slope}}} \right) \]  

(2.23)

### 2.3. AC/DC System Integration and Model Verification

Valuable work regarding the dynamic modelling of either AC or DC systems has been carried out, and several power flow approaches for steady-state AC/DC systems have been proposed. However, integrated AC/DC system models for power system stability studies are often based on either simplified AC systems [28] (e.g. AC systems are represented by a voltage source behind an impedance) or simplified DC systems [30] (e.g. DC systems are considered as power injections at the connected AC buses). Also the integration method has also not been addressed in detail, even though integrated models are seen in [58, 64]. This is based on the fact that the bandwidths of the DC system’s components are normally much higher than the AC system dynamics, allowing one to be simplified for modelling. However, there might still be possible interactions between the VSC outer control loops with lower bandwidths and the AC system electromechanical modes. Therefore, an integration method is introduced in this section to include the cascaded VSC control structures and AC system controls in an AC/DC stability model where the potential controller interactions and system dynamics can be captured.
In this section, a generic method is proposed to integrate VSC terminals into AC systems taking into account the cascaded VSC control structures. The method allows the VSC models to be developed separately by considering them as voltage-controlled current injections into the connected AC system, and it therefore provides an alternative for quickly integrating new VSC models into conventional power system models. It is valid for integrating an arbitrary number of VSC HVDC terminals. The developed integrated model is a mathematical model for stability studies which is linearized at a pre-defined operating point via load flow calculations. Hence an AC/DC power flow [24-27] needs to be performed first. Modal analysis techniques can be readily applied to the whole integrated AC/DC model, and the effects of VSC controls on the AC system power oscillations can be analysed mathematically.

**DC Line Model**

In addition to the VSC models introduced before, the DC line model is necessary for linking VSC terminals to form a DC grid. The DC lines are represented by pi section models. According to Fig. 2.18, the equation for the DC line circuits are:

\[
\frac{C_{dc}}{dt} V_{di} = i_{dc1} - i_{dc} \\
\frac{C_{dc}}{dt} V_{dj} = i_{dc2} + i_{dc} \\
L_{dc} \frac{i_{dc}}{dt} = V_{di} - V_{dj} - R_{dc} i_{dc}
\]

Fig. 2.18 DC line model.
where $V_{dci}$ and $V_{dcj}$ are both input terms provided by the two connected converters. The DC line current is calculated and fed back into the converters. Depending on the number of terminals, the equation can be extended into a matrix which includes all the line dynamics of the DC grid [28]. In some cases, the capacitance of the cable $C_{dc}$ can be combined with the converter capacitance $C_{vsc}$ for simplicity, and therefore the dynamics of $C_{dc}$ are included in the converter DC voltage equation (2.13).

**Integration Method**

As reviewed in the previous chapter, there exist several AC/DC power flow algorithms. For integration, a unified AC/DC load flow approach\textsuperscript{1} is chosen to calculate the initial conditions of both AC and DC variables in this case. This serves as an initial operating point for the stability model which will be developed in the following sections.

The integrated AC/DC model for stability studies is similar to the idea of the unified AC/DC power flow approach, where the solved DC system equations are combined into the AC system calculations. However, the dynamics of the DC system need to be taken into consideration. In this section the integration method is described from a generic point of view where an arbitrary number of VSC terminals are considered as current injections to the connected AC system, despite the type of the outer control loops employed in the VSCs. The AC system solves the network equations and provides the voltages at the PCC buses back to the DC grid as a reference for the VSCs and PLLs, as presented in Fig. 2.19.

\textsuperscript{1} Described in DlGSIILENT PowerFactory 15.1 technique reference.
Consider a conventional power system stability model with generators only, the voltages at the generator buses (PV bus) are initially known from load flow calculations. It is the generator bus currents and the non-generator bus (PQ bus) voltages that need to be solved, as presented in equation (2.27). This requires an iterative procedure to reach the final convergence in load flow calculations. For the stability model, this can be expressed by linear equations, and it is desirable to reduce the network by eliminating the nodes in which the current do not enter or leave.

\[
\begin{bmatrix}
I_g \\
I_x
\end{bmatrix} =
\begin{bmatrix}
Y_K & Y_L \\
Y_L^T & Y_M
\end{bmatrix}
\begin{bmatrix}
V_g \\
V_x
\end{bmatrix}
\]

In the above equation, the system admittance matrix \( Y \) is partitioned into four parts\(^1\): \( Y_K, Y_L, Y_L^T \), and \( Y_M \). \( I_g \) and \( V_x \) are, respectively, the vectors of system injection currents (generator currents) and non-generator bus voltages that need to be solved. \( I_x \) is a null vector representing the buses without any current injections. Given the generator bus voltages \( (V_g) \), it is possible to calculate \( I_g \) and the rest of the non-generator bus voltages \( V_x \) as:

\[
I_g = Y_K V_g + Y_L V_x
\]

\[
I_x = 0 = Y_L^T V_g + Y_M V_x
\]

Solving the above two equations gives:

\[
V_x = -Y_{red} Y_L^T V_g
\]

\[
I_g = (Y_K - Y_L Y_{red} Y_L^T) V_g = Y_{red} V_g
\]

where \( Y_{red} \) is the reduced admittance matrix that is normally used for conventional power system stability models. It should also be noted that constant loads in the AC

\(^1\) Note that it contains \( Y_L \) and \( Y_L^T \) due to its symmetric nature.
system can be considered as self-admittances of the connected bus, and they can be added to the original network admittance matrix as:

\[ Y_{ii,\text{load}} = \frac{(P_i - jQ_i)}{V_i^2} \]  

where subscript 'i' stands for bus i.

When VSC terminals are added into the network model (it is assumed that the VSC terminals are NOT connected at the same buses as the generators), the element \( I_x \) is affected by the current injected or absorbed by each one of them, and it will no longer be a null vector. If the VSC terminals and generators are nominally connected at one bus, they can always be split by use of a dummy bus and a small impedance connection. The network equation is then affected by VSCs. In this case, \( I_x \) will still be a known vector as the current injections from the VSC terminals are known from the load flow calculations initially. However, it will then be constantly modified when new current injections from the VSC terminals are calculated. In this way the system admittance matrix can remain unchanged with VSCs.

When considering the effect of VSC currents, equation (2.29) can be modified as:

\[
I_x = Y_L^TV_g + Y_M^TV_x \\
\text{and } I_x = [i_{vsc}]
\]  

Here \([i_{vsc}]\) is a column vector of \( n \) rows \((n=\text{number of non-generator buses})\) that consists of non-zero elements (i.e. VSC current injections) and zeros. The non-zero elements will depend on the location of the VSC terminals.

Solving the network equations now gives:

\[
V_s = Y_M^TV_g - Y_M^T(I_x - Y_L^TV_g) \\
I_g = Y_K^TV_g - Y_L^TV_M^T(I_x - Y_L^TV_g)
\]  

This calculates the bus voltages required by VSC terminals as well as the current required by generators with \( I_x \) constantly modified by \([i_{vsc}]\).

The complete integrated system diagram is shown in Fig. 2.20. Generators control their terminal voltages via AVRs, and provide their bus voltages to the AC network. The non-generator bus current vector is constantly modified by VSC terminals. This
will then affect the network calculation of the generators’ currents as well as all the system bus voltages. After solving the network, the voltages at the PCC buses are then fed back into the VSCs, and the generator currents are fed back to generators. The above process forms a loop which represents the interaction between the AC and DC systems during operation.

\[ I = YV \]

**Fig. 2.20** Complete diagram of the integrated model.

Attention should be given to the directions of the VSC currents which will affect the signs of the corresponding elements in vector \( I_x \). It is also worth noting that this is a small signal model, meaning that load flow calculations are required for different operating points.

**Integrated Generic AC/DC System**

The integration method was tested by constructing a linearized AC/DC model in Matlab. The VSC HVDC model is developed based on [12, 64], and it is suitable for small signal stability analysis. The key state equations as well as some important parameters used in this point-to-point VSC HVDC link model are provided in Appendix C4.

Dynamic simulations were used to validate the model against the same model built in DIgSILENT PowerFactory. The two-area system developed before is used as the AC system, with a point-to-point VSC HVDC link connected in parallel with the tie-lines carrying 200MW power from bus 7 to bus 9. Bus 7 and bus 9 are considered as
the PCC buses for the DC link. The integrated system is shown in Fig. 2.21. The VSCs in the DC link are configured to regulate the DC side voltage (VSC1) and output powers (VSC2) to the AC system. A complete set of linearized VSC equations for VSC1 and VSC2 are provided in Appendix C4.

A remote AC system self-clearing three-phase short circuit is simulated at bus 1 for 100ms. The DC link voltage will be disturbed due to the variations in the PCC bus voltage following the AC fault. The DC voltage responses of both integrated AC/DC models (the mathematical model and PowerFactory model) are presented in Fig. 2.22. Some high frequency components are absent from the mathematical model but the comparison of the transient response still shows good agreement.
Conclusion

This chapter has presented the basic concepts and mathematical modelling of the key components in both AC and DC systems. This provides a summary of the models that were developed in past literature and have appropriate levels of fidelity for power system stability studies.

The conventional method of AC system modelling is described, including models of synchronous generator, power system branches, loads and AC networks. A generic two-area system is firstly constructed as a basis for DC system integration in the later stage. The second part of the chapter details the analytical VSC HVDC model for power system stability study. The cascaded VSC control structure has been explained from the fastest valve level control to the slowest system level control. Emphasis has been put on the converter level control, which has the bandwidths most relevant to the power system electromechanical transient behaviours. Various VSC control strategies have been presented for different applications that will be analysed further in later chapters.

A novel integration method has been proposed for the developed AC and DC system models. This method has been demonstrated by constructing a mathematical AC/DC test system, the dynamic performance of which is validated against a same model constructed in DlgsILENT PowerFactory. As the state variables in the integrated model are accessible and power system analysis techniques (e.g. modal analysis) can be readily applied for analysis, the constructed two-area AC system with a paralleled VSC HVDC link will serve as a generic test system for further AC/DC control interaction studies in this thesis.
Chapter 3. Dynamic GB System Modelling

In order to extend the fidelity of the generic AC system modelling, this chapter introduces the development of a dynamic equivalent representative Great Britain (GB) like system\(^1\) with the intention of reproducing more realistic responses and power flow constraints. However the simulation should not be so complex as to be over-burdened with excessive detail in the course of study which actually focuses on new concepts. Because of the simplifications that are made in this reduced model, the results should not be regard as accurately representing the behaviour of the real full system. However, by resembling the full GB network in a reduced model, the construction of scenarios and the interpretation of results will be easier and more targeted than using classical benchmark models. In this chapter, detailed construction procedures of the key network components are described, together with the associated control schemes. The method of adding “dynamics” to an available steady-state network is shown. The final dynamic system model exhibits different characteristics – as the system condition varies – which can be used for the studies throughout the thesis.

3.1. Background

Instead of using fictitious or historic networks, a reference steady-state network is modified to become a “dynamic GB system model”. The construction mainly involves detailed models for generators and shunt devices with their associated control systems, transmission lines and loads. Power system stabilizers (PSS) in the

\(^1\)The author would like to gratefully acknowledge Manolis Belivanis and Keith Bell at the Department of Electronic and Electrical Engineering, University of Strathclyde, for providing the steady state data for the representative model of the electricity transmission network in Great Britain.
synchronous generators are modelled and designed to damp local oscillatory modes leaving the inherent system characteristic to be reflected clearly. The data of a reference steady-state model is available in [71, 72] which provides detailed model data of the 2010 electricity network of GB that anticipates the 2010/11 “average cold spell” (ACS) winter peak demand loading conditions, as well as the planned transfer to meet that demand. The steady-state data has been validated against a solved AC load flow reference case provided by National Grid Electricity Transmissions (NGET).

To add dynamics into the steady-state network, the main procedures are summarized in Table 3.1. Details of each step will be discussed in this chapter which is intended to provide a road map for the method of construction of a dynamic AC system model.

<table>
<thead>
<tr>
<th>No.</th>
<th>System Construction Procedures</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Construction and validation of the reference case steady-state network model data.</td>
</tr>
<tr>
<td>2</td>
<td>Determination of main components modelled at each bus and their corresponding dynamic parameters.</td>
</tr>
<tr>
<td>3</td>
<td>Development and design of dynamic control schemes for particular components if required.</td>
</tr>
<tr>
<td>4</td>
<td>Testing and identification of the system’s main characteristic features under various conditions. The developed system should be small disturbance stable initially.</td>
</tr>
</tbody>
</table>

3.2. Steady-state System Construction

The steady-state equivalent system model is firstly constructed to build up the structure of the system, and it is necessary for the validation against the load flow data of the reference case. This includes the aspects of generation, loading and losses in the system. The main structure and the inherent characteristics of the system are actually determined at this stage. The reference network model is depicted in Fig. 3.1 on top of a GB map, which clearly shows the corresponding locations of the nodes and transmission lines. Each node is considered as a bus station (PQ, PV and slack bus) in the steady-state network model, and the nodes are linked by network
branches. For completeness, the full steady-state network data is provided in Appendix D1.

Fig. 3.1 Representative GB network model overview (modified from [72]).

**Network Branches**

As presented in Fig. 3.1, the model consists of 29 buses, interconnected through 99 transmission lines with 49 double-circuit configuration lines and one single-circuit line. These transmission lines represent the main routes for the power flows across the GB transmission system. For a balanced system, the network branches are defined using parameters for only positive phase sequence resistance, reactance and shunt susceptance. Winter post-fault thermal ratings that should not be exceeded for a credible system loading condition are also defined. Most transmission lines in England (the South part) have a nominal voltage of 400kV, while there are a few lines in Scotland (the North part) with nominal voltages of 275 kV. Transmission lines between two buses with different voltage levels are considered to operate at the voltage level of the higher bus (e.g. a 400kV transmission line is used to connect a...
275kV bus and a 400kV bus, and a line transformer is used to step up the 275kV bus voltage to 400kV). Phase shift (Quadrature Booster) transformers are included at two branches with two degree phase shift at the locations shown in Fig. 3.1. Interconnections with external systems through interconnectors are modelled including the links from the South East of England to France and to Netherlands. However, the interconnector at bus 5 (from the South West of Scotland to Northern Ireland) is not included in the reference load flow scenario, and thus it is excluded in this model. The reference load flow suggests that UK is exporting power to external systems through the interconnectors, and these interconnectors will be treated as constant power load.

**Bus Components**

A typical node bus structure is shown in Fig. 3.2. 24 out of 29 buses have generating units connected to them. The option of one type of synchronous generator model per bus is applied, and these buses are configured as PV buses while the rest of the buses are PQ buses and the slack bus (bus 27). Generator rated power is configured using the value of “available generation” summarized from the 2010/11 National Grid Seven Year Statement (SYS). “Effective generation” is calculated by applying an S factor to the “available generation” (e.g. 0.72 for wind-farms, 1 for normal generation, 0 for non-contributory generation), and this is the exact generation in the reference load flow scenario. The generators are all aggregated models which represent the dominant type of generation in a particular area, and they will be distinguished by their dynamic parameters. Generator transformers are included in order to facilitate the utilization of standard generator models with low terminal voltages in the later stages for dynamic simulations. However, the impedances of these generator transformers are kept small as they are not the focus of the model and are less significant in comparison with the transmission line impedances in the system. Shunt devices – such as mechanically switched capacitors, reactors and static VAr compensators (SVCs) in the system – have been represented in the model with what are judged to be appropriate reactive power capabilities at equivalent
locations. At this stage, they are provided to either generate or absorb reactive power at a given value to match the provided load flow scenario.

System demand is modelled directly at the high voltage nodes as constant impedance static loads with the values given by the ACS winter peak demand condition. In absence of detailed information on the load composition, static loads can normally be modelled as constant impedance loads, assuming that the load is mostly resistive. This representation may be shifted towards constant current or even constant MVA if the load is most comprised of motor-driven units [47]. Each load also contains the effects of the reduced parts of the actual network that represent the series active and reactive power transmission losses on the lines, which are not shown in this network. More accurate load modelling might be appropriate at a later stage for in-depth analysis of phenomena considered. Other loading conditions such as summer minimum demand can be modelled by suitable scaling of the load and generation power across the entire system. An example of a light loading condition system model is also presented in this chapter after the winter peak loading condition system is developed.

At this point, when the network branches and buses are properly configured, the developed steady-state model is able to, in principle, reproduce the active power flows and line losses across all the main transmission routes of the GB network. Furthermore, it preserves active and reactive power transmission losses on the lines as well as the shunts within the reduced parts of the network. Steady-state load flow analysis can be performed at this stage. With additional dynamics added into the system, research on power system control and stability issues can be carried out.
Model Validation

The steady-state equivalent model was constructed in DIgSILENT PowerFactory (DSPF) and the load flow results were validated against the available reference case scenario.

Table 3.2 Validation between reference case and the developed model (five significant figures).

<table>
<thead>
<tr>
<th>Data</th>
<th>Total Power</th>
<th>Reference Load Flow</th>
<th>DSPF Load Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>P_{gen}</td>
<td>60294 (MW)</td>
<td>60293 (MW)</td>
</tr>
<tr>
<td></td>
<td>Q_{gen}</td>
<td>12363 (MVar)</td>
<td>12333 (MVar)</td>
</tr>
<tr>
<td>Load</td>
<td>P_{load}</td>
<td>59844 (MW)</td>
<td>59844 (MW)</td>
</tr>
<tr>
<td></td>
<td>Q_{load}</td>
<td>40368 (MVar)</td>
<td>40368 (MVar)</td>
</tr>
<tr>
<td>Loss</td>
<td>P_{loss}</td>
<td>450.50 (MW)</td>
<td>449.13 (MW)</td>
</tr>
</tbody>
</table>

Due to the inclusion of generator and line transformers, the resulting system’s voltage profile is slightly different from the reference case, causing some elements, like the switched shunts, to behave differently. This in turn has some effects on the established reactive power balance. However, as presented in Table 3.2, the developed model is very close to the reference case scenario in terms of active power flow and losses. This indicates that both the resulting active power flow in all transmission lines and the bus angles match the reference case data. The total installed generation of this network is approximately 75GW with the peak demand around 60GW. The power is mainly transferred from the North to the South. A schematic diagram of the GB system power flow is provided in the Appendix D1.

3.3. Dynamic Generator Design

The basic steady-state model offers the basis for the design of a dynamic system model. To focus on the analysis of electromechanical transients in a balanced system, the generation units are key components to be further modelled to include transient dynamics and controls. It should be noted that typical or standard data may be used during the construction process in absence of actual generation data. Generic control schemes are also expected to suffice when new concepts or general phenomenon are explored. Therefore, the results obtained may be considered only as indications of potential problems.
Generator Type Selection

The generation information is summarized from the 2010 “Seven Year Statement” (SYS) and a full AC load flow solution provided by National Grid in [73]. The installed capacity at each bus, provided in the generation information (supplied by “GB network model” data sheet), is the sum of the power station “transmission entry capacities” of each generation type in the area of the bus. Such capacity is the maximum amount of power that a power station is allowed to send onto the UK network. This information will be used to assess the contribution of various generation types in the same bus. Following the option of one type of generator model at each bus, the strategy is to use the generation with dominant output power to represent the entire generation type at the bus.

The selected generation types are parameterized with the corresponding dynamic data recommended in [74] to distinguish their dynamic behaviours. The number of paralleled generators will be determined based on the total available generation. The final one generator model will have equivalent reactance and inertias of the total number of paralleled generators. For instance, the generation information of bus 4 is presented in Table 3.3. The large unit coal of 2284MW is the dominant type of generation. Therefore it is selected as the generator type for the entire bus. The data in SYS shows that the large coal generation units in bus 4 are mainly of capacity around 400-500MW. To meet the total effective generation of the entire bus (2980MW), seven paralleled large unit coal generators with 400-500MW unit capacity were considered in bus 4. The specific standard generator type data is obtained by choosing the best match in [74].

Table 3.3 Example the generator type selection.

<table>
<thead>
<tr>
<th>Bus</th>
<th>Generation Type</th>
<th>Available Power Capacity (MW)</th>
<th>Total Generation</th>
<th>Selected Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>4. Denny/ Bonnybridge</td>
<td>Wind Onshore</td>
<td>25.20</td>
<td>2908 (MW)</td>
<td>Large Unit Coal x7</td>
</tr>
<tr>
<td></td>
<td>Large Unit Coal</td>
<td>2284.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Pumped Storage</td>
<td>340.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>CHP</td>
<td>259.00</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
After repeating the selection procedure for all buses with generating units, there are nine types of resulting dominant generator types in the GB network model which are summarized in Table 3.4.

<table>
<thead>
<tr>
<th>Generation Type</th>
<th>Specific Types</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro Units</td>
<td>H11, H14</td>
</tr>
<tr>
<td>Nuclear Units</td>
<td>N3</td>
</tr>
<tr>
<td>Fossil (Coal) Units</td>
<td>F15</td>
</tr>
<tr>
<td>CCGT Units</td>
<td>CF1, CF2, CF3, CF4</td>
</tr>
<tr>
<td>Windfarm Units</td>
<td>Converter</td>
</tr>
</tbody>
</table>

It should be noted that bus 6 is dominated by windfarm generation and is modelled as a static generator. This model represents a group of wind generators which are connected through a full-size converter to the grid. The reason for such a representation is that the behaviour of the wind power plants (from the view of the grid side) is mainly determined by the connection converter. With this representation, the factors that are important for windfarm designs but do not play a decisive role for the windfarm responses from a system standpoint are put aside. A typical independent real and reactive power control [75, 76] is employed for the windfarm units, which will deliver constant power into the grid.

The final selected equivalent generators in the GB system model consist of five fossil fuel generators, six nuclear generators, ten CCGTs, two hydro generators, and one wind generator. All generating units utilize detailed sixth order synchronous generator models except the wind generator. A detailed summary of the final generation type selections and the corresponding dynamic data is given in Appendix D2.

**Generator Controls**

Satisfactory AC system operation is obtained when system frequency and voltages are well controlled. Therefore, modelling of generator controls is also essential for the development of the dynamic system model. This may include the modelling of
excitation system, governors and power system stabilizers depending on the focus of the study performed.

**Excitation System**

Generators are equipped with excitation systems for terminal voltage control. The slower DC1A excitation systems are used in most types of generation in the system as they have been widely implemented by the industry for coal, gas, and hydro plants. Large and newly constructed nuclear plants are equipped with fast ST1A excitation systems, which have a higher gain and smaller time constant. Automatic voltage regulation (AVR) is performed through excitation control that supplies the excitation winding of synchronous generators. Standard IEEE parameters recommended in [77] are used. A detailed block diagram representation of the type DC1A excitation system is depicted in Fig. 3.3.

![Diagram of Excitation Systems](image)

Fig. 3.3 IEEE type DC1A and ST1A standard excitation systems.

The terminal voltage of the synchronous machine is sensed and usually reduced to a DC quantity. The filtering associated with the voltage transducer may be complex. It can usually be reduced for modelling purposes to the single time constant $T_R$ as shown in Fig. 3.3. A signal derived from field voltage is normally used to provide excitation system stabilization $V_F$. An error signal is obtained after subtracting the stabilizing feedback $V_F$ and $V_C$ from the reference voltage set point. This error is amplified by the regulator, with $K_A$ and $T_A$ as the gain and the major time constant respectively. The amplified signal is used to control the exciter to provide the
desired excitation field voltage $E_{fd}$. The exciter saturation function $S_E[E_{fd}]$ is defined as a multiplier of exciter output voltage to represent the increase in exciter excitation requirements due to saturation.

A type ST1A excitation system is also shown in Fig. 3.3, where the excitation is supplied through a voltage transducer from the generator terminals with a time constant $T_r$. The voltage regulator gain in this case is $K_a$, which is set quite large while any inherent excitation system time constant is neglected. This type of excitation system is simpler but faster than the type DC1A. The parameter data of the excitation systems can be found in Appendix D2.

**Turbine Governors**

The inclusion of governor models depends on the subject of research. For electromechanical transient studies where frequency stability is not considered, governor models can be omitted since their response time is longer than the dynamics of interest. It can be assumed that there is sufficient inertia in the AC system to render changes in frequency small over the time frames modelled. However, for long term stability studies where frequency is of concern, governors need to be modelled so that the generation units will respond to system power mismatches following disturbances.

Since the prime sources of electricity energy supplied by utilities are the kinetic energy of water and the thermal energy derived from fossil fuels and nuclear fission, hydraulic turbines and steam turbines are used to represent the governors in the AC system for different types of generators. Both turbine models are described here.

![Fig. 3.4 Typical turbine governor models.](image-url)
Fig. 3.4 shows typical hydraulic and steam turbine governor models. The basic function of a hydraulic governor is to control speed or load by feeding back speed error to control the gate position. The transient droop compensation enables the governor to exhibit a high droop (low gain) for fast speed deviations and normal droop (high gain) in steady-state. $T_w$ here represents the “water starting time”, which is the time required for a head to accelerate the water in the penstock from standstill to the operating velocity. The hydraulic turbine is modelled as a classical transfer function, showing how the output power is related to the changes in the gate opening for an ideal lossless turbine. $T_w$ normally varies with load, with typical values from 0.5-4s. $T_G$ is the main servo time constant typically set to 0.2s. The temporary droop $R_T$ and reset time $T_R$ can normally be determined as [20]:

$$R_T = [2.3 - (T_w - 1) \times 0.5] T_w / T_m \quad (3.1)$$
$$T_R = [0.5 - (T_w - 1) \times 0.5] T_w \quad (3.2)$$

where the mechanical starting time $T_m = 2H$ (inertia constant).

A steam turbine converts stored energy of high pressure and high temperature steam into rotating energy, which is in turn converted into electrical energy by the generator (Fig. 3.4). The heat source for the boiler supplying the steam can be a nuclear reactor or a furnace by fossil (e.g. coal, oil, gas). Hence the steam turbine model can be used for generation of type CCGT, fossil, nuclear etc. The control action is stable with normal speed regulation of 5% droop, and thus there is no need for transient droop compensation. $F_{HP}$ is the fraction of the total turbine power generated by high pressure sections, which is normally of value 1/3. $T_{RH}$ is the time constant of reheater, which is also the most significant time constant encountered in controlling the steam flow and turbine power. In comparison, $T_{CH}$ (time constant of main inlet volumes and steam chest) is normally small and can be neglected. Fig. 3.5 exemplifies the speed responses of a synchronous generator supplying an isolated load with different turbine governing models. A 140ms three-phase fault was applied at the high voltage end of the connection transformer.
Power System Stabilizer

Power system stabilizers add damping to the generator rotor oscillation by controlling the excitation voltage through auxiliary stabilizing signals. The actual GB system is in fact a very stable system with properly tuned local modes. Therefore, for generators with unstable or poorly damped local modes, PSSs are also required to be designed. Some techniques are used for determining the parameters of the PSSs. This is specified in the following section. The inherent characteristics of the system are then examined after the local modes are properly damped.

3.4. Individual PSS Design

The design of each PSS is based on a mathematical single machine infinite bus (SMIB) model established for every generator in the GB system. The operating point of each SMIB is made the same as the corresponding generator in the GB system, and their parameters are scaled accordingly to the number of generators in parallel at each bus. A residue based designing technique is addressed in this section, and the resulting designed PSSs are put back into the GB system model. Turbine governor models are not included at this stage for PSS tuning, and thus the mechanical turbine power inputs for the generators are configured to be of constant values.
Basic Concepts
Tuning of the PSS has been a well-developed research area, and various methods have been proposed ranging from classic linear control [78, 79] (e.g. residue, frequency responses based method) to more complex theories [45] (e.g. Linear Matrix Inequalities, Model Linear Quadratic Gaussian method). However, in practice, classical tuning methods are overwhelmingly used by engineers due to their simplicity and applicability. As the basics of all other tuning methodologies, the classical control analysis theories are preferred at early stages of system design. They are therefore used here since the target of adding PSSs in this study is to reflect the essence of the system, but not to optimize the system behaviour.

The basic concept of damping torque provided by PSS in synchronous generators is described by the Phillips Hefron Model [80, 81], as presented in Fig. 3.6, which relates the concepts of small perturbation stability of a single machine supplying an infinite bus through external impedance with the effects of excitation voltage. The concept of synchronizing and damping torques can be introduced based on this model [81].

At any given oscillation frequency, braking torques are developed in phase with the machine rotor angle and rotor speed. Torques in phase with the machine rotor angle are termed as synchronizing torques, whereas damping torques are developed to be
in phase with rotor speed. Any torque oscillations can be broken down into these two components, and a resultant stable system indicates a balance between synchronizing and damping torques.

Fast responding exciters equipped with high gain normally increase the synchronous torque coefficient of the system, resulting in reduced levels of stability. The purpose of a PSS is to introduce a damping torque component to counteract this effect utilizing the generator’s speed signal. This is achieved by adding an auxiliary signal to the exciter’s input voltage. Appropriate phase compensation is required in PSSs to compensate for the phase lag between the exciter’s input and the electrical torque. A block diagram in Fig. 3.7 shows the typical structure of PSS that consists of four key components: a phase compensation block, a signal washout block, a low pass filter block and a gain block.

The stabilizer gain $K_{pss}$ determines the amount of damping introduced by the PSS. Normally, the damping effect increases with the stabilizer gain — up to a certain point beyond which further increase in gain will lead to a decrease in damping. Ideally, the stabilizer gain is set at a value corresponding to maximum damping. However, the gain is often limited by other physical considerations. The washout block in the PSS acts as a high pass filter to only allow signals associated with oscillations in the input signal to pass unchanged. This way, the steady-state changes in the input signal do not affect the terminal voltage through PSSs. A suitable setting for the time constant $T_w$ would be a proper value that is long enough to achieve its filter function, but not so long that it leads to undesirable generator voltage excursions during system-islanding conditions [20]. Sampled frequency responses of typical washout blocks are also shown in Fig. 3.7, where the bandwidth is seen increased with higher $T_w$ value. For initial settings, $T_w = 1.5s$ is enough for local mode oscillations in the range of 0.8 to 2 Hz, while $T_w = 10s$ or higher should be used for low frequency inter-area oscillations. A PSS may also include a low pass filter which is used to prevent interaction with high frequency (usually torsional) modes. This together with washout block minimise the interaction of the control signal with the rest of the system beyond 0.2-2.5Hz.
As previously mentioned, to damp rotor oscillations, the PSS must produce a component of electrical torque in phase with the rotor speed deviation. Therefore, there are phase compensation blocks included to provide an appropriate phase-lead characteristic to compensate for the phase lag difference between the exciter input and the resulting electrical torque. The phase lag is normally caused by frequency dependent gain and phase characteristics exhibited in both generators and exciters. For a small degree of phase compensation, a single first order compensator may be enough. This number can increase when larger phase compensation is required. The compensated phase value normally varies to some extent with different system conditions. Slight under-compensation is usually preferred so that the PSS does not contribute to negative synchronizing torque component [20].

**Transfer Function Residue Based PSS Design**

Among the many classical techniques for PSS design, the transfer function residue based implementation method is to be used for the GB system damping controllers [79, 82]. The concept of residue is described in Appendix A2 and briefly reviewed here. A single open-loop transfer function can be extracted from a multi-input multi-output system as shown in equation (3.3), where the residue at the pole $\lambda_i$ is defined
as $R_i$. According to control theory, the residue provides information regarding the angle of departure as well as the magnitude of the shift of the eigenvalues. Therefore, the idea here for damping controller PSS design is to achieve desired shifting of the critical poorly damped or unstable modes based on their corresponding residue value:

$$G(s) = C(sI - A)^{-1}B = \sum_{i=1}^{n} \frac{R_i}{s - \lambda_i}$$  \hspace{1cm} (3.3)

The residue can also be calculated by the eigenvectors if the state variables are expressed using the transformed state variables where each one state is only associated with one mode. This is given as:

$$R_i = C\phi_i\nu_i B$$  \hspace{1cm} (3.4)

The PSS feedback signal is required to enable a large impact on the residue of the target mode in order to obtain sufficient controllability over the mode of oscillation to be damped [83]. As previously discussed, the transfer function of PSS takes the following form:

$$H(s) = K \times W(s) \times L(s)^N = K_{pss} \left( \frac{sT_w}{1 + sT_w} \right) \left( \frac{1 + Ts}{1 + \alpha Ts} \right)^N$$  \hspace{1cm} (3.5)

The time constant of the washout block is pre-set and the low pass filter is not included in this case as torsional interactions are not considered. $K_{pss}$ is the gain of PSS, which will be determined by the amount of damping required during the tuning process. An appropriate number of phase lead-lag blocks $L(s)^N$ will be designed to provide adequate phase compensation. Therefore, the parameters that need to be determined during the tuning procedure are: $K_{pss}$, $T$, and $\alpha$. The PSS is designed for the exciter control loop compensation. The implementation is based on transfer function residues, Following Lyapunov’s first method for system stability. Unstable or poorly damped modes are shifted to be more damped in the left half-plane. The amount of shifting can be expressed by the residue of the open loop transfer function according to the following equation [79].

$$|\Delta \lambda| = |R_i||H(\lambda_i)|$$  \hspace{1cm} (3.6)
where $\Delta \lambda_i$ is the corresponding eigenvalue shift with $H(\lambda_i)$ as the transfer function of PSS. $R_i$ is the residue of the open loop transfer function corresponding to $\lambda_i$.

The residue of the transfer function between the exciter input voltage $\Delta V_{\text{ref}}$ and output speed $\Delta \omega$ can be calculated via equation (3.4), based on which the corresponding residue phase angle of critical eigenvalues is identified. These modes should be shifted towards the left without any changes in frequency for best damping effect [82], indicating that the shift direction needs to be $\pm 180^\circ$, and that it requires proper phase compensation in PSSs. A phase lead-lag block which takes the form of $L(s)$ in equation (3.5) is used. Depending on the value of $\alpha$, $L(s)$ can be either a phase lead block $(T>\alpha T)$ or a phase lag block $(T<\alpha T)$. The maximum phase lead or phase lag occurs halfway between the pole and zero frequencies of $L(s)$, and this should be targeted at the frequency of the critical eigenvalues. A discussion of the frequency characteristics of a typical phase lead-lag compensator and the effects of its parameter settings in the frequency domain are provided in Appendix A4.

To ensure a shift direction of $\pm 180^\circ$, the required compensation phase angle $\theta_{\text{pss}}$ is determined after calculating the residue angle. The value of $\alpha$ in the lead-lag compensator needs to be properly set, so that the maximum phase compensation occurs at the particular frequency $\omega_i$ of targeted critical modes ($\lambda_i=\sigma_i \pm \omega_i$) [82]. This method is briefly summarized as follows:

$$\theta_{\text{pss}} = \pm 180^\circ - \theta_{\text{residue}} \quad (3.7)$$

$$N = \frac{\theta_{\text{pss}}}{57^\circ} = \begin{cases} 1, & \theta_{\text{pss}} \leq 60^\circ \\ 2, & 60^\circ < \theta_{\text{pss}} \leq 120^\circ \\ 3, & 120^\circ < \theta_{\text{pss}} \leq 180^\circ \end{cases} \quad (3.8)$$

$$\alpha = \frac{\sin \left( \frac{\theta_{\text{pss}}}{N} \right)}{1 + \sin \left( \frac{\theta_{\text{pss}}}{N} \right)} \quad T = \frac{1}{\omega_i \sqrt{\alpha}} \quad (3.9)$$

The compensation angle per lead-lag block should normally be restricted within $0^\circ$-$57^\circ$ to ensure an acceptable phase margin and acceptable noise sensitivity at high frequencies. This is limited by the value of $\alpha (0.087 < \alpha < 10)$ to avoid excessive
noise interference). Once the phase compensation is determined, the gain of PSS $K_{pss}$ can be found by plotting the root locus of the system voltage-speed loop with the designed PSS as a feedback. The damping normally increases with the stabilizer gain. However, the gain of PSS is also restricted in order to limit the interactions with other controllers. The final value of the gain is set to effectively damp the critical system modes without compromising the stability of other system modes or causing excessive amplification of signal noise (typically $K_{pss}$ is set less than 50).

**Example System PSS Tuning**

An example of PSS tuning for one of the generators in the GB system is provided here to demonstrate the key procedures discussed before. In this tuning process, the criteria of 5% minimum damping ratio is applied for all system modes as electromechanical oscillations with damping ratios greater than 5% are considered satisfactory in a power system [84]. With such a damping ratio, the oscillation in the system will decay in about 13s. For the case of PSS tuning for the generators in the GB system, the SMIB equivalents are investigated. Generators with poorly damped (damping ratio <5%) or unstable modes are further designed with a PSS for improved stability.

![Fig. 3.8 Single line diagram for SMIB.](image)

Aggregated generator 11 is used as an example here (Fig. 3.8). This is a nuclear type generator which is equipped with type ST1A excitation system. An equivalent SMIB mathematical model was developed to represent the paralleled machines at bus 11. The aggregated generator model has inertia ($H$) and impedance scaled from the
original standard machine, based on the number of paralleled generators. Time constants of the standard machine remain unchanged. The resulting aggregated generator model has output real power equivalent to the effective generation given by the total number of paralleled generators in bus 11 (4576MW) in the load flow scenario. Furthermore, the branch impedance needs to be properly adjusted so that the voltage and reactive power flow conditions of the equivalent model are the same as the case in the GB system model. Eigenvalue analysis of the equivalent SMIB model results in a pair of unstable eigenvalues, as shown shaded in Table 3.5. The pair of unstable eigenvalues represents the critical electromechanical modes of this system that will cause the system to go unstable. These modes need to be damped by a properly designed PSS that compensates the excitation loop of the system with the form of:

$$K_{pss}(\frac{sT_w}{1+sT_w})(1+sTs)^N$$

(3.10)

<table>
<thead>
<tr>
<th>No.</th>
<th>Eigenvalues</th>
<th>Damping Ratio %</th>
</tr>
</thead>
<tbody>
<tr>
<td>λ1</td>
<td>-2883.4</td>
<td>100</td>
</tr>
<tr>
<td>λ2</td>
<td>-2861.1</td>
<td>100</td>
</tr>
<tr>
<td>λ3</td>
<td>-33.947</td>
<td>100</td>
</tr>
<tr>
<td>λ4</td>
<td>-5.0771+12.417i</td>
<td>37.85</td>
</tr>
<tr>
<td>λ5</td>
<td>-5.0771-12.417i</td>
<td>37.85</td>
</tr>
<tr>
<td>λ6</td>
<td>-12.95</td>
<td>100</td>
</tr>
<tr>
<td>λ7</td>
<td>0.37695+6.385i</td>
<td>-5.89</td>
</tr>
<tr>
<td>λ8</td>
<td>0.37695-6.385i</td>
<td>-5.89</td>
</tr>
<tr>
<td>λ9</td>
<td>-0.80765</td>
<td>100</td>
</tr>
</tbody>
</table>

The value $T_w$ for the washout block is pre-set to a typical value of 10s. Calculating the residue of the transfer function with input $V_{ref}$ and output $\Delta \omega$ results in $R_i = -0.14+j0.06$ where the residue angle is 157.24°. Therefore, the phase compensation required in this case is $180° - 157.24° = 22.76°$. To provide this phase compensation for the targeted eigenvalue at frequency $\omega_i=6.385 \ (rad/s)$, a PSS phase lead block can be determined using criteria equations (3.8) and (3.9). The results are calculated as:

$$N=1, \ \alpha=0.442, \ T=0.236.$$
To determine the gain $K_{\text{pss}}$, the root loci of the transfer function between the generator reference voltage and output speed with PSS as feedback is plotted (Fig. 3.9). The gain is increased until the critical modes reach the desired location in the stable area. Meanwhile, some other stable modes may go unstable or become less damped as the gain of PSS increases. The method adopted here is that the gain of PSS is set to a value of 30% to 35% of the critical gain (when the other modes reach the stability boundary). In this case, as the gain increases, the unstable eigenvalues $0.377 \pm 6.386$ shift to the left half-plane with damping ratio greater than 5% (dashed line). However, another pair of eigenvalues $-5.077 \pm 12.42$ is shifting right to be poorly damped with a critical PSS gain value of $K_{\text{pss}}=28$. Therefore, the PSS gain is set to a value of $K_{\text{pss}}=28 \times 30\% = 8.4$ to avoid other system modes going unstable.

![Root Locus Diagram](image)

Fig. 3.9 Root locus for generator 11 PSS gain selection (Positive frequency only).

Adding the designed PSS, the full list of the SMIB system eigenvalues is shown in Table 3.6, where the initial unstable modes are properly damped without excessively deteriorate other system modes. This process needs to be carried out for the rest of the generators in the GB network model. The equivalent SMIB mathematical model (Fig. 3.8) will be repeatedly used but with different parameters settings for other aggregated generator models. For those generators with no poorly damped or unstable modes, PSSs are not required. The results of all necessary PSS parameters
are summarized in Table 3.7, and these PSSs are put back into the full GB system model so that all the local modes in the system can be well damped.

Table 3.6 Full list of eigenvalues for the SMIB system of generator 11 with PSS.

<table>
<thead>
<tr>
<th>No.</th>
<th>Eigenvalues</th>
<th>Damping Ratio %</th>
</tr>
</thead>
<tbody>
<tr>
<td>λ1</td>
<td>-2883.4</td>
<td>100</td>
</tr>
<tr>
<td>λ2</td>
<td>-2861.1</td>
<td>100</td>
</tr>
<tr>
<td>λ3</td>
<td>-34.649</td>
<td>100</td>
</tr>
<tr>
<td>λ4</td>
<td>-2.1123+13.755i</td>
<td>15.18</td>
</tr>
<tr>
<td>λ5</td>
<td>-2.1123-13.755i</td>
<td>15.18</td>
</tr>
<tr>
<td>λ6</td>
<td>-12.516</td>
<td>100</td>
</tr>
<tr>
<td>λ7</td>
<td>-11.561</td>
<td>100</td>
</tr>
<tr>
<td>λ8</td>
<td>-1.4755+5.4509i</td>
<td>26.13</td>
</tr>
<tr>
<td>λ9</td>
<td>-1.4755-5.4509i</td>
<td>26.13</td>
</tr>
<tr>
<td>λ10</td>
<td>-0.80553</td>
<td>100</td>
</tr>
<tr>
<td>λ11</td>
<td>-0.10064</td>
<td>100</td>
</tr>
</tbody>
</table>

Table 3.7 PSS tuning results.

<table>
<thead>
<tr>
<th>Gens</th>
<th>Kpss</th>
<th>Tw</th>
<th>T</th>
<th>αT</th>
<th>Number of L(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G2</td>
<td>16.52</td>
<td>10</td>
<td>0.044</td>
<td>0.240</td>
<td>2</td>
</tr>
<tr>
<td>G3</td>
<td>3.68</td>
<td>10</td>
<td>0.633</td>
<td>0.064</td>
<td>3</td>
</tr>
<tr>
<td>G11</td>
<td>9.33</td>
<td>10</td>
<td>0.236</td>
<td>0.104</td>
<td>1</td>
</tr>
<tr>
<td>G12</td>
<td>22.31</td>
<td>10</td>
<td>0.033</td>
<td>0.210</td>
<td>2</td>
</tr>
<tr>
<td>G16</td>
<td>4.68</td>
<td>10</td>
<td>0.657</td>
<td>0.122</td>
<td>3</td>
</tr>
<tr>
<td>G19</td>
<td>3.83</td>
<td>10</td>
<td>0.965</td>
<td>0.146</td>
<td>2</td>
</tr>
<tr>
<td>G20</td>
<td>6.97</td>
<td>10</td>
<td>0.258</td>
<td>0.085</td>
<td>1</td>
</tr>
<tr>
<td>G22</td>
<td>3.57</td>
<td>10</td>
<td>0.491</td>
<td>0.065</td>
<td>3</td>
</tr>
<tr>
<td>G23</td>
<td>19.87</td>
<td>10</td>
<td>0.034</td>
<td>0.453</td>
<td>3</td>
</tr>
<tr>
<td>G26</td>
<td>15.76</td>
<td>10</td>
<td>0.034</td>
<td>0.191</td>
<td>2</td>
</tr>
<tr>
<td>G27</td>
<td>10.93</td>
<td>10</td>
<td>0.259</td>
<td>0.212</td>
<td>1</td>
</tr>
<tr>
<td>G28</td>
<td>21.34</td>
<td>10</td>
<td>0.037</td>
<td>0.289</td>
<td>2</td>
</tr>
</tbody>
</table>

Dynamic GB System Characteristics

The dynamics of the reduced GB network model are established with the detailed generator models and the controls. As it is difficult to get access to the data that is owned by generating companies, and excessive to model a full real time network,
standard generator and control data are considered to be detailed enough for general dynamic and stability studies. The developed model enables initial stage modelling of many key phenomena of new technologies, such as renewable generation and VSC HVDC integration that are associated with the GB-like AC system. An overview of the developed dynamic system model is given in Fig. 3.10.

The whole system at this stage has 230 total states which include the dynamic models of all generating units with their corresponding control systems. Among these eigenvalues, 23 of them would be electromechanical modes as there are 24 generators in the system (one generator, G27, is configured as the slack generator for reference). It should also be noted that generator 6 is modelled as a windfarm connected through a converter, which means this generator will not be visible, leaving only 22 electromechanical modes.

The established GB system is well damped by the designed PSSs which is true for the actual real system. However, there might be inherent stability problems if the system condition varies. Therefore, when analysing the stability issues, different

Fig. 3.10 Overview of the developed “dynamic GB system”.

- 93 -
possible system scenarios are considered which will push the system to its stability margins, and the inherent characteristics of the system may become more obvious in those cases. These conditions are detailed below.

**GB System with Inter-area Oscillation**

The first “weakened” system condition is one with reduced number of PSSs, in which case the system’s damping torque is reduced. A low frequency inter-area mode is detected in the system in a particular case where the PSS in the generator at bus 16 (shaded in Table 3.7) is removed. This PSS has the largest participation factor to the low frequency mode of the originally developed system, and thus removing it results in reduced damping ratio of the mode.

![Eigenvalues of original system](image1)

![Eigenvalues of the system with inter-area mode](image2)

![Mode shape of inter-area mode](image3)

Fig. 3.11 (a) Eigenvalues of original system, (b) Eigenvalues of the system with inter-area mode (Eigenvalues plot for positive frequencies near 0 only and the dashed line denotes 5% damping) and (c) Mode shape of inter-area mode.
A comparison of the eigenvalues of the originally established dynamic GB system and the modified version (PSS at bus 16 removed) is given in Fig. 3.11 (a) and (b). The modified system has a pair of poorly damped inter-area oscillation modes (-0.091±j3.04) with damping ratio of 3% and damped frequency of 0.48Hz. This indicates that there is a low frequency inter-area oscillation which exists in the network model involving two groups of generators swinging against each other. In order to understand the coherency of the generators, a mode shape compass plot can be used to illustrate the behaviour of the generators as it shows the relative activity of the state variables in a particular mode. The normalized right eigenvector, corresponding to rotor speeds of the generators in the system, of the inter-area mode, is given in Fig. 3.11 (c) to show the grouping of generators in the inter-area oscillation (mainly between G1-G4, G10 and the rest of the generators).

Time domain simulations show generator speed responses when the system is subjected to a self-clearing 100ms three-phase fault at bus 10. This will cause a maximum tie-line power oscillation of around 500MW. The speed responses of G1-G5 in Scotland and G23-29 in England are illustrated by Fig. 3.12. The oscillation takes more than 30s to damp and the figure is enlarged at the end, where the inter-area oscillation is most obvious. The grouping of generators which have similar behaviour can be observed. During the oscillation, when generators G1-G5 have a decrease in speed, generators G23-G29, on the contrary, have an increase in speed and vice-versa. The G2’s speed response has a half cycle period of 1.04s illustrating the 0.483Hz inter-area low frequency oscillation in the developed system model, and this validates the eigenvalue analysis provided before.

![Fig. 3.12 Generator speed responses during AC system fault event.](image-url)
This characteristic GB system condition with the 0.483Hz inter-area oscillation represents the incidents of the UK system in 1980 [85] where two groups of generators in Scotland and England were oscillating against each other. This is used as a base case of the GB system for stability studies in this thesis.

**Heavily Stressed System**

The system can be further pushed to its stability limits when it is heavily stressed. To meet a particular pattern and level of demand, there are always choices about which generators to use. This then affects the resulting load flow condition throughout the system, and in some particular cases the system can be stressed. The actual dispatch of generation will generally follow what is sometimes referred to as "merit order", i.e. use the cheapest units first and keep committing units in turn. These units are generally operated at maximum output, except those which require 'headroom' for primary reserve. These units have the priority to contribute first until the total load demand and network losses are met. The power transfers across any boundary would depend on exactly where these 'in merit' units are relative to the individual loads. However, there are also uncertainties such as wind availabilities and outages which also change the load flow pattern.

Thus, for a particular level of demand, the dispatch of generation can be modified. As a consequence, the power flows from one region to another vary. One case that can stress the system is to have a different dispatch of generation. Export of power from Scotland could be very high under low demand (i.e. off peak) and high wind conditions, in which a “merit order” dispatch of generation would favour low carbon generation located in Scotland. However, to simplify this process, an alternative way is to adjust the load demand to also change the power flow between the areas. For example, the system can be stressed by considering all generation in Scotland as being 'in merit'. Because Scotland would be a net exporting region, the highest level of export would actually be under an off peak demand condition. The demand within Scotland would be small in comparison to the total generation in the area, and hence the power exported to England will be large. However, to be a credible situation,
there should not be any thermal branch overloads in the dispatch. Nonetheless, the highest possible export without any overloads is likely to be a more suitable testing case from a stability point of view.

More specifically, the system is stressed by increasing the generation in the Scotland (Node 1-8) to their maximum available generation. Meanwhile, the load demand in Scotland (Loads in Node 1-8) is reduced by a scaling factor $x (x < 1)$, and the reduced load demand is uniformly added to the England network (Loads in Node 9-29). Under such circumstances, more power will be transferred from the North to the South, which will push the system towards its stability margin as illustrated in Table 3.8 and Fig. 3.13. It is observed that with an increasing amount of power transferred from Scotland to England (as shown in the tie-line 8-10 power responses), the system can result in oscillatory instability due to insufficient damping torque.

Table 3.8 Calculated inter-area mode when system is stressed.

<table>
<thead>
<tr>
<th>Scaling Factor</th>
<th>Inter-area mode</th>
<th>f in Hz</th>
<th>Damping ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>$x=1$</td>
<td></td>
<td>0.48</td>
<td>2.92%</td>
</tr>
<tr>
<td>$x=0.9$</td>
<td></td>
<td>0.48</td>
<td>2.07%</td>
</tr>
<tr>
<td>$x=0.8$</td>
<td></td>
<td>0.48</td>
<td>1.21%</td>
</tr>
<tr>
<td>$x=0.7$</td>
<td></td>
<td>0.47</td>
<td>0.35%</td>
</tr>
<tr>
<td>$x=0.6$</td>
<td></td>
<td>0.47</td>
<td>-0.49%</td>
</tr>
</tbody>
</table>

Fig. 3.13 System responses when stressed.
3.5. Shunt Device Dynamic Modelling

The SVC units installed in this GB system were initially modelled as constant reactive power support to match the reference load flow scenario. However, for dynamic studies, the SVCs need to be modelled in voltage control mode in response to voltage variations in the system [86]. The SVC modelled in this case consists of thyristor controlled reactors (TCRs) and thyristor switched capacitors (TSCs). Ideally it should hold constant voltage by possessing unlimited VAr generation/absorption capability instantaneously, as shown in Fig. 3.14.

![Fig. 3.14 SVC Model and ideal VI characteristic.](image)

The basic structure of a TCR is a reactor in series with a bidirectional thyristor switch [87]. Its partial conduction characteristic is determined by the firing angle $\alpha$ that is in the range of $90^\circ$-$180^\circ$. Firing angles between $0^\circ$-$90^\circ$ are not allowed as they produce asymmetrical currents with a DC component. A TCR normally responds in about 0.02-0.1s, taking into consideration delays introduced by measurement and control circuits. On the other hand, the TSC scheme consists of a capacitor bank split up into several similar sized units which can be switched in or out of the scheme. An inductor is normally included to limit switching transients, damp inrush current and prevent resonance with network. Although the control of the TSC unit (by varying the number of TSC units in conduction) is discontinuous, the voltage control of the SVC can be made continuous by using the TCR to smooth out the variations in the effective susceptance.

The TCR and TSC schemes together form the SVC. The maximum compensating current of a SVC decreases linearly with the AC system voltage, and the maximum
MVAr output decreases with the square of the voltage. The maximum transient capacitive current is determined by the size of the capacitor and the magnitude of the AC system voltage. In practical implementation, a droop characteristic [20] (a slope value typically between 1-5%) is normally set for the SVC voltage regulation, as shown in Fig. 3.15 (c). Within the linear control range, the SVC is equivalent to a voltage source ($V_{ref}$) in series with a reactance (e.g. $X_{Sl}$) which represents adjustable admittance.

Two SVC control schemes are also illustrated in Fig. 3.15 (a) and (b). The first one, Fig. 3.15 (a) utilizes a proportional type control with gain $K_R$, which is the inverse of the slope. Lead-lag blocks may be added to provide adequate phase and gain margin when high steady-state gain is used. Alternatively, the droop characteristic may also be configured through a current feedback as shown in Fig. 3.15 (b). The voltage regulator can then be a PI controller type, and the controller gain and the slope setting of SVC are independent from each other in this situation. Both controllers are manipulating the susceptance of the SVC to control the compensation current. Please see [87] for more detailed control settings.

An example of a SVC (-200MVAr capacitive to +50MVAr inductive) supplying a SMIB system with the control scheme shown in Fig. 3.15 (a) is given in Fig. 3.16.
where the system is subjected to a 140ms three-phase fault at the SVC controlled bus. A voltage drop and recover are seen during the fault at the SVC connected bus. The SVC is injecting reactive power (capacitive) into the system during the fault, attempting to hold the bus voltage by increasing its susceptance to its upper limit. It then absorbs reactive power (inductive) from the system to bring the bus voltage from the small overshoot back to 1 p.u. after the fault. Due to the characteristic of the SVC, its reactive power capability is limited by its terminal bus voltage. Therefore, it is not providing its rated reactive power during the AC system fault, although it has reached its susceptance limits.

The SVCs are modelled at appropriate locations for the dynamic GB system model as specified in the reference case with the control schemes mentioned before. They are supporting the voltage of their connected buses.

Fig. 3.16 Dynamic responses of SMIB system with SVC (negative Q is capacitive SVC operation).
3.6. Light Loading GB System

Other loading conditions of the developed GB system can also be modelled by properly scaling the existing load flow scenario. Future scenarios provided in the National Grid ODIS show that the system will have a large proportion of renewable generation. However, potential problems may occur when conventional generators with large inertias (e.g. fossil coal, CCGT) are replaced by low inertia renewable generators (e.g. offshore wind power) which are normally decoupled from the system by power converters. In order to address this, a test system condition with such features can be established. This section shows the method of modifying the system into a lightly loaded condition (e.g. summer time light loading) system with large wind power penetration.

According to the summary from National Grid, the “Total Gross System Demand” is used to determine the total amount of load demand at different times of a year. This is calculated from generation data which includes station load, pump storage and interconnector exports. The minimum loading condition can be estimated based on such data. The main procedures for developing a light loading system are summarized as:

i. All the fossil generation units are closed in the system, and the nuclear generation units in the Scotland part are closed (i.e. G4, G5, G7, G15, G17, G18 and G23 are disconnected from the system). These units are considered as conventional generation which will be replaced by renewable generation.

ii. More windfarm injections are added into the system as suggested in ODIS. Specifically, windfarms are modelled at bus 2 (1GW), bus 5 (2GW), bus 7 (2GW), bus 12 (1GW), bus 19 (2GW) and bus 26 (1GW) as suggested by the planned Round 3 windfarms. In total this introduces 9GW wind power injection into the system. The original generation at those buses is considered to be replaced by windfarm generation, and thus the original generation is disconnected from the system. For practical implementation of wind power grid connection, there may be reactive power compensation devices installed.
at the grid entry point for windfarms, and thus SVC with appropriate reactive power capability may be modelled along with the added windfarms [88].

iii. In order to reach a light loading condition based on the data in [73], CCGT generation units are scaled down to reach a total system generation of around 25GW. All the system loads are also scaled down accordingly to match the new generation. The power of all remaining generation in the system as well as the interconnectors remains unchanged.

The above modifications would result in a light loading system with a total generation of 25GW which represents the future summer minimum demand condition of the developed AC system model with a large proportion (circa 40%) of wind power penetration. Table 3.9 provides the summary of the resulting generation of different loading conditions, where the total windfarm generation is increased from 0.87GW to 9.85GW. Hydro and nuclear type generators are maintained due to their inflexibility. A dramatic decrease is seen for CCGT type generation (from 2.81GW to 0.5GW). Modal analysis of the light loading condition system shows that the system is well damped, with all the system modes damping ratios above 10%. There are no inter-area modes in this case when the load demand is largely reduced.

<table>
<thead>
<tr>
<th>Generation Type</th>
<th>Generation for heavy loading (MW)</th>
<th>Generation for light loading (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>1634.00</td>
<td>1634.00</td>
</tr>
<tr>
<td>CCGT</td>
<td>28111.00</td>
<td>4961.00</td>
</tr>
<tr>
<td>Wind</td>
<td>871.00</td>
<td>9845.00</td>
</tr>
<tr>
<td>Nuclear</td>
<td>11545.00</td>
<td>8237.76</td>
</tr>
<tr>
<td>Coal</td>
<td>18180.64</td>
<td>0.00</td>
</tr>
<tr>
<td>Total Generation</td>
<td>60341.64</td>
<td>24677.75</td>
</tr>
</tbody>
</table>

To compare the dynamic performance of the developed heavy and light loading conditions of the system, time domain simulations are performed. In this case, the system is disturbed by two typical events: (1) AC system three-phase fault event and (2) variations in load demand. In this case, the focus is put on system voltage and frequency responses in order to investigate the differences between the two loading conditions of the system in respect of the voltage and frequency controllability. The
comparison is made between the buses with the largest voltage/frequency deviations. Such buses are selected by observing and comparing the voltage/frequency responses of all system buses during an event. The comparison of the resulting voltage and frequency responses of the selected buses in two different loading conditions are given in Fig. 3.17 and Fig. 3.18. As the conventional generation with slow DC1A exciters is closed in the light loading condition, its voltage control is largely determined by the fast ST1A exciters. A large portion of generation is provided by the windfarms with constant power factor control. These windfarms behave in a similar manner to active loads in the system. Therefore, for the three-phase fault event, system voltages converge very quickly with less oscillation in the lightly loaded condition. However, the largest amount of voltage deviation right after the fault is almost the same for both cases. The frequency responses of both system conditions for the AC fault event are also very similar.

![Fig. 3.17 Bus 2 voltage and bus 29 frequency responses for a 100ms self-clearing three-phase short circuit event at bus 24.](image)

As governors are not included in the model for this case, the load ramp event causes a power mismatch in the system (loading>generation). Under such circumstance, the system frequency starts to decrease. Comparison in Fig. 3.18 shows a more rapid frequency decrease initially with the heavy loading condition rather than the light loading condition. This is because the rate of change of frequency in the initial stage
depends not only on the system inertia but also the amount of power mismatch in the system. After the initial stage, the light loading condition has a faster frequency decrease rate. Nevertheless, the light loading condition has faster voltage control.

![Graph of Bus 2 voltage and frequency responses for 1GW ramp up change in 2s in load 25](image)

Fig. 3.18 Bus 2 voltage and frequency responses for 1GW ramp up change in 2s in load 25

## 3.7. Conclusion

In this chapter a dynamic “representative GB system” is developed, based on a realistic reference case. A detailed road map of the key procedures for the dynamic construction of the system is provided together with all the necessary system data required to reconstruct such a system. This mainly includes the methods used for generator dynamic parameters selection, controller design and system condition adjustment to finally achieve a system model with particular characteristic features. The developed system is modified for different system conditions. These system conditions are useful depending on the particular focus of one’s subject of research. One of the system conditions has the characteristic of a low frequency inter-area oscillation with most of the generators in the system participating. Such a phenomenon is demonstrated using both small disturbance analysis and time domain simulations. This is mainly caused by the generators in the Scottish part (G1-G4)
oscillating against the generators in England, with a damping ratio less than 5%. More stressed system conditions are also discussed where the inter-area oscillation becomes more obvious and the system can be pushed beyond its stability margin. Additionally, a light loading system condition is also developed, which has improved the system voltage control capability due to the remaining fast exciters in the system. However, frequency control in such a system condition becomes more challenging as the total system inertia is reduced.

As the developed model provides a dynamic equivalent representation of a GB transmission network, further analysis on AC/DC interactions can be carried out based on this network model. The use of this more realistic large power system model helps to ensure that the results obtained are representative of practical system implementations.
Chapter 4. The Effect of VSC HVDC Control on AC System Electromechanical Oscillations and DC System Dynamics

The operating point and the control strategies employed in VSC based HVDC systems can substantially affect the electromechanical oscillatory behaviour of the AC network as well as the DC side dynamics. In order that the full, flexible capability of VSC HVDC can be exploited, the study of the effects of these controllers and their interactions with AC system responses is necessary. This chapter provides a full assessment of the effect of VSC controls in a point-to-point DC link and a four-terminal DC system. Both modal analysis and transient stability analysis are used to highlight trade-offs between candidate VSC outer controls and to study the electromechanical performance of the integrated AC/DC model. Tests are carried out with both the two-area system model and the dynamic GB system model.

4.1. Methodology for VSC Control Assessment

VSCs have complex hierarchical control structures. A variety of these has been proposed and analysed [11, 31, 34, 38, 53, 59, 61-63, 67, 69], but the focus has been the delivery of required performance on the DC side and within the converter rather than the interaction with the AC system. The AC system has thus not been modelled in detail in these cases. Conclusions have been reached about the efficacy of droop control [61, 67] used in multi-terminal DC grids and supplementary power oscillation damping (POD) controllers [33, 34]. AC system studies have also been undertaken, but the focus
Chapter 4. The Effect of VSC HVDC Control

has been on the AC system dynamics — the VSC HVDC system and controllers have typically been severely abstracted [30, 33, 34]. A holistic approach needs to be taken which utilizes a detailed AC/DC modelling methodology and control designs to systematically compare candidate VSC HVDC controllers.

In this chapter the VSC outer power and voltage controls are analysed. Taking into considerations of the control loop bandwidth (from a few Hz to tens of Hz), the methodology used to compare these controls is to study: (1) the control effects on AC system inter-area oscillation and (2) the control effects on DC system dynamic responses. The analysis is focused on the case of a point-to-point DC link embedded within each of two test AC systems. One is the two-area system designed for inter-area electromechanical oscillation analysis [20]. This facilitates the analysis of the effects of VSC HVDC without being obscured by complex AC system structures. The second AC test network is the dynamic GB system developed in Chapter 3, with the intention of validating using more realistic system parameters. The use of the large power system model with realistic constraints and reinforcement strategies facilitates the practicality of the studies carried out and the generalization of conclusions.

4.2. Control Parameterization

The control system for VSC has a hierarchical cascaded structure which can be classified into three levels, as shown in Fig. 4.1, with bandwidth separation. In this case, the outer controllers (L2) will be focused on and analysed. The fast inner loop (L1) includes the DC to AC voltage conversion and a decoupled vector current control (dq current control). A phase locked loop (PLL) is employed to lock on to the point of common coupling (PCC) voltage and to provide the reference angle for the VSC. The typical VSC outer control schemes that fall into the category of L2 are listed in Table 4.1. For convenience, the abbreviations in Table 4.1 are used in the rest of this chapter.

---

1Fig. 4.1 is reproduced here for convenience. Detailed descriptions for the cascaded controls are available in Chapter 2.
Chapter 4. The Effect of VSC HVDC Control

The closed-loop bandwidth of the VSC outer control loops refers to the frequency where the magnitude of the response is equal to -3dB. Normally, the bandwidth falls into the range of a few Hz to tens of Hz (e.g. 1-20Hz). It is therefore possible for these controllers to influence the electromechanical behaviours of the connected AC system. In this section, the parameterization of these outer controllers is discussed. To undertake this task, it is assumed that the inner current loops are fast enough to be simplified as constant gains, and the AC system dynamics are considered as infinite buses. The notations defined in Fig. 4.1 are used here.

With power invariant dq transformation and the assumption that the rotating reference frame is aligned to the d-axis, the VSC output power at the PCC bus can be expressed as:

\[ p = v_d i_d + v_q i_q \approx v_d i_d \]  

(4.1)
\[ q = v_{dq} i_d - v_d i_q \approx -v_q i_q \]  

(4.2)

where \( v_{dq} \) and \( i_{dq} \) are the voltages and currents at the PCC bus. These equations are used by \( FFP \) and \( FFQ \), which relate directly the real and reactive power orders to \( dq \) current orders, and therefore no additional outer controllers are introduced. The block diagram representations of the feedforward type PQ controls are presented in Fig. 4.2.

Droop control adds an additional gain to the FF or FB power loops, and sets the allowable DC voltage variations for given power limitations. To cover the typical droop gains, the range of \( 1 < k_{droop} \leq 30 \) will be considered [61]. With respect to the four FB type outer control loops with additional PI controllers (i.e. \( FBV_{dc} \), \( FBP \), \( FBQ \), \( FBV_{ac} \)), the parameter settings can be determined by means of frequency responses of closed-loop transfer functions.

**Modelling of Feedback DC Voltage Loop**

The dynamics of the \( FBV_{dc} \) controller are dominated by the DC side capacitor, and they are expressed as:

\[
C_{eq} \frac{dV_{dc}}{dt} = i_c - i_{dc} = \frac{v_d i_q}{V_{dc}} - i_{dc}
\]

(4.3)

Linearizing gives:

\[
\Delta C_{eq} \frac{dV_{dc}}{dt} = \frac{-v_q i_q}{V_{dco}^2} \Delta V_{dc} + \frac{v_d}{V_{dco}} \Delta i_d + \frac{i_q}{V_{dco}} \Delta v_d - \Delta i_{dc}
\]

(4.4)
where a subscript ‘o’ represents the operating point value. Based on the above equation, the closed control loop can be represented by Fig. 4.3 (a). Let $K_V = v_{do}/V_{dco}$ and $K_G = i_{do}/V_{dco}$, the closed-loop transfer function is expressed as:

$$\frac{V_{dc}}{V_{dc}^*} = \frac{k_{pdc} K_V s + k_{ide} K_V}{C_{eq} s^2 + (K_V K_G + k_{pdc} K_V) s + k_{ide} K_V}$$

This equation can be further approximated to a second order transfer function (assuming $k_{pdc} \ll k_{ide}$) as:

$$\frac{V_{dc}}{V_{dc}^*} = \frac{k_{ide} K_V}{s^2 + \frac{K_V (K_G + k_{pdc})}{C_{eq}} s + \frac{k_{ide} K_V}{C_{eq}}} = \omega_n^2$$

This allows an approximation of an initial tuning value for the controller for a given natural undamped frequency $\omega_n$ and damping ratio $\zeta_{dc}$.

![Fig. 4.3 VSC FB type control block diagram representations.](image-url)
Chapter 4. The Effect of VSC HVDC Control

Modelling of Feedback Real and Reactive Loops
Based on equations (4.1) and (4.2), the closed FB real and reactive power control loops can be defined as Fig. 4.3 (b) and (c). Ignoring the disturbance terms, the plant model for both real and reactive power is mainly determined by the operating point PCC voltage $\pm v_{do}$, which can be represented by a gain $g$ at an operating point. Then the closed-loop transfer function for both $FBP$ and $FBQ$ takes the form of a first order transfer function as (assuming $k_{pPQ} \ll k_{iPQ}$):

$$\frac{x}{x^*} = \frac{g k_{pPQ} s + k_{iPQ}}{s + g k_{pPQ} s + k_{iPQ}} \approx \frac{k_{iPQ}}{s + k_{iPQ}} \quad (g = \pm v_{do})$$

(4.7)

where $x$ can be either $P$ or $Q$. The target bandwidth can be initially approximated by $k_{iPQ}$.

Modelling of Feedback AC Voltage Loop
For the FB type AC voltage control, the closed-loop transfer function derivation is slightly more involved. Assuming an infinite AC bus with voltage $V_s \angle 0^\circ$ (Fig. 4.1), after dq transformation, the following equation was established:

$$(v_d + jv_q) - (V_{sd} + jV_{sq}) = (R_x + jX_x)(i_d + ji_q)$$

(4.8)

Solving gives:

$$v_d = V_{sd} + R_x i_d - X_x i_q$$
$$v_q = V_{sq} + R_x i_q + X_x i_d$$

(4.9)

For an ideal PLL, the PLL angle varies with the PCC bus voltage angle, and so are all other system parameters in the dq domain. The infinite bus voltage $V_s \angle 0^\circ$ in the dq domain is:

$$\begin{bmatrix} V_{sd} \\ V_{sq} \end{bmatrix} = \begin{bmatrix} \cos \theta & \sin \theta \\ -\sin \theta & \cos \theta \end{bmatrix} \begin{bmatrix} V_s \end{bmatrix}$$

(4.10)

where $V_{sd} = 0$ and $V_{sq} = V_s$. Angle $\theta$ is the PLL angle.

With equations (4.9) and (4.10), and the rotating reference frame being aligned with the d-axis (i.e. $v_q = 0$), the PCC bus voltage is now given as:

$$v = \sqrt{v_d^2 + v_q^2} \approx v_d = V_s \cos \theta + R_x i_d - X_x i_q$$

(4.11)
Chapter 4. The Effect of VSC HVDC Control

The closed-loop transfer function for $FBV_{ac}$ can then be expressed as Fig. 4.3 (d) which is disturbed by $R_{do}$ (related to the operating point of the DC link) and $V_{cos}\theta$. The closed-loop transfer function is, however, similar to equation (4.7), where the bandwidth can be initially approximated by $k_{iac}$.

The above simplified control closed-loop transfer functions of the four FB type controls allow quick tuning of the controllers, after the initial approximation, to achieve a given closed-loop bandwidth. More accurate controller parameters can be further set by examining the frequency responses of the closed-loop transfer functions via Matlab software (Matlab pidtool) with the tuning techniques outlined in [89]. For each FB type control loop, a set of parameters is tuned for the outer controllers to cover their typical bandwidth range in preparation for comparison purposes in the later stages. Fig. 4.4 shows an example of the feedback real power control closed-loop frequency response after it is tuned to a bandwidth of 5Hz.

![P control close loop frequency response](image)

Fig. 4.4 Example of closed-loop frequency responses.

### 4.3. Method of Analysis

The influence brought by the control strategies on the AC and DC side of the system is investigated separately with different methodologies.

**Effects on AC System**

From the perspective of the AC side, the investigation focuses on the impact of VSC HVDC link on inter-area electromechanical modes in the AC system. In order to
identify the critical oscillatory modes, the eigenvalues of the system with frequencies in the range of 0.2 to 1 Hz need to be scanned. Two modal analysis techniques are used: (1) the QR method [90], which is robust for small power systems, and (2) the Arnoldi method [91], which can be implemented with sparsity techniques to calculate a specific set of eigenvalues with certain features of interest (e.g. the low frequency inter-area modes in this case). The Arnoldi method is considered efficient to solve partial eigenvalues for large integrated AC/DC systems. The application of this sparsity based eigenvalue technique to the small disturbance stability analysis of a large power system was presented in [92]. The detailed critical mode tracking procedure is illustrated by Fig. 4.5 which shows an iterative process. One controller will be varied while all the other controllers in the DC link remain the settings of a based case. Targeting at low frequencies, the inter-area mode can be tracked.

As AC system inter-area oscillations are complex and involve a large number of generators, a generic small two-area system with a characteristic inter-area mode is firstly investigated. The QR method is used to track the critical oscillatory mode for this small system. The key findings are then tested with the larger and more realistic representative GB system, where the Arnoldi method is applied for inter-area mode monitoring.

**Effects on DC System**

The dynamic responses on the DC side of the system are much faster than those on the AC side. Hence the effects of VSC controls on the DC system are less influenced by the AC side dynamics and they are better shown by DC side transient responses. Therefore, the controls are compared by monitoring the dynamic responses of DC system.
parameters. Different controller parameter settings, based on the tuning procedures discussed before, are applied to provide a sensitivity analysis showing the resulting system behaviours. The main focus of this research is on normal operating conditions, and thus the test conditions modelled do not cause control limiters to be activated.

4.4. Investigation Based on Generic AC System

The classical two-area AC system developed before is firstly used in these studies. This detailed system model is described in Chapter 2 and the system diagram is again presented in Fig. 4.6. This is a detailed integrated AC/DC system with sixth order generator models, and VSC models employing control schemes shown in Fig. 4.1.

In the following studies, the term “fast” and “slow” controls will be used to represent an FB type control which is tuned with a bandwidth of 30Hz and 1Hz respectively. The purpose of this is to push a particular controller to its parameter setting limits to show the corresponding effects under certain conditions.

![Generic two-area system with embedded VSC HVDC link.](attachment:image)

**Effects of VSC Outer Controls on Inter-area Mode**

The idea here is to investigate the AC system inter-area oscillation under the effect of different VSC outer control schemes and operating points. Specifically, the AC system
low frequency inter-area mode is monitored by applying QR method to the whole system matrix with different VSC HVDC configurations. However, for FB type controllers, as they can be configured differently depending on the outer controller, the investigation of their effects needs to cover their typical settings. This is achieved by including a *bandwidth* sensitivity analysis for each of these FB controls detailed in test case 2.

**Test Case 1: Comparison of FF and FB Type Controls**

Two control scenarios are listed in Table 4.2, where $FBV_{dc}$ is configured to a *bandwidth* of 10Hz in both cases. The FF type PQ controls in Scenario 1, which do not require additional controllers, are examined first. The QR method is applied to obtain the inter-area mode for different power flow conditions in the DC link. The resulting inter-area mode frequencies ($f$) and damping ratios ($\xi$) are listed in Table 4.3. All the FF type PQ controls in Scenario 1 are then replaced by FB type PQ controls (Scenario 2) with identical bandwidths. The same test now yields results shown in Table 4.4.

### Table 4.2 VSC control settings case 1.

<table>
<thead>
<tr>
<th>Control Scenarios</th>
<th>VSC1</th>
<th>VSC2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1</td>
<td>$FBV_{dc}$</td>
<td>FFQ</td>
</tr>
<tr>
<td></td>
<td>FFQ</td>
<td>FFP</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>$FBV_{dc}$</td>
<td>FBQ</td>
</tr>
<tr>
<td></td>
<td>FBQ</td>
<td>FBP</td>
</tr>
</tbody>
</table>

### Table 4.3 Inter-area mode tracking with FF type controls.

<table>
<thead>
<tr>
<th>DC link power</th>
<th>Inter-area mode</th>
<th>$f$ Hz</th>
<th>$\xi$ %</th>
</tr>
</thead>
<tbody>
<tr>
<td>50MW</td>
<td>0.56Hz</td>
<td>3.82%</td>
<td></td>
</tr>
<tr>
<td>150MW</td>
<td>0.56Hz</td>
<td>4.54%</td>
<td></td>
</tr>
<tr>
<td>250MW</td>
<td>0.56Hz</td>
<td>5.25%</td>
<td></td>
</tr>
<tr>
<td>350MW</td>
<td>0.55Hz</td>
<td>5.86%</td>
<td></td>
</tr>
</tbody>
</table>

### Table 4.4 Inter-area mode tracking with FB type controls.

<table>
<thead>
<tr>
<th>DC power</th>
<th>Inter-area mode</th>
<th>Slow FB controls</th>
<th>Fast FB controls</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$f$ Hz</td>
<td>$\xi$ %</td>
<td>Frequency</td>
</tr>
<tr>
<td>50MW</td>
<td>0.56Hz</td>
<td>3.45</td>
<td>0.57Hz</td>
</tr>
<tr>
<td>150MW</td>
<td>0.58Hz</td>
<td>3.32</td>
<td>0.58Hz</td>
</tr>
<tr>
<td>250MW</td>
<td>0.58Hz</td>
<td>3.07</td>
<td>0.58Hz</td>
</tr>
<tr>
<td>350MW</td>
<td>0.57Hz</td>
<td>2.66</td>
<td>0.57Hz</td>
</tr>
</tbody>
</table>
Chapter 4. The Effect of VSC HVDC Control

Originally, without the embedded DC link, the two-area system has an inter-area mode of \( f=0.545\,\text{Hz} \) and \( \xi=3.2\% \) [20]. According to the results in Table 4.3, it is seen that the inter-area mode damping ratio increases with the DC link power when FF type PQ controls are employed. In contrast, adding the DC link with FB type PQ controls (Table 4.4), the inter-area mode damping ratio decreases with the DC link power. In both cases the frequency of the mode remains largely the same. A faster or slower FB type PQ controller does not influence significantly the inter-area mode. This is validated by a time domain simulation in Fig. 4.7, which compares the tie-line power responses for both scenarios with different DC link powers following a three-phase 100ms self-clearing fault at bus 5.

*Test Case 2: Effects of Individual FB Type Controls*

Case 2 focuses on individual FB type control schemes. In setting up the comparison of various control parameters in this case study, a reference base case is firstly defined. The DC link is now configured with a control strategy specified in Table 4.5, i.e. all the FB control loops are tuned to have a *bandwidth* of 5Hz, except \( FBV_{dc} \) that is tuned to 10Hz. This serves as the reference base case, so that the resulting closed-loop step responses for these FB type controls have no significant overshoot, a 10%-90% rise time of 0.1s and no steady-state error.

<table>
<thead>
<tr>
<th>Table 4.5 VSC control settings case 2.</th>
</tr>
</thead>
<tbody>
<tr>
<td>VSC1</td>
</tr>
<tr>
<td>( FBV_{dc} )</td>
</tr>
</tbody>
</table>
The $FBQ$ in VSC2 was changed to $FBV_{ac}$ when analysing the effect of AC voltage control. The procedure of the bandwidth sensitivity analysis is a set of iterative processes where one controller will be varied with different bandwidths by adjusting the outer loop PI controller each time, while all the other controllers in the DC link remain at the settings of the reference case. In this case, one outer controller – $FBV_{dc}$ in VSC1, $FBP$, $FBQ$ or $FBV_{ac}$ in VSC2 – is varied for testing. For two DC link operating points, the root loci of the inter-area mode, which is affected by different control settings, are plotted in Fig. 4.8 (a) and (b) with arrows indicating the directions of increasing controller bandwidth. The bandwidths of the controllers here are pushed to a larger range (1-30Hz) to more clearly show the movement of the inter-area mode.

![Diagram](image.png)

Fig. 4.8 Root loci of inter-area mode with bandwidth variations in individual FB type control loop at (a) 100MW DC link power and (b) 200MW DC link power.
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The results, illustrated by Fig. 4.8 (a) and (b) for 100MW and 200MW DC link power flow conditions respectively, lead to the following conclusions:

2a. The inter-area mode damping ratio increases with the bandwidth of \( FBV_{ac} \), \( FBP \) and \( FBQ \). However, such an impact is very small in comparison to the effect of the bandwidth variations in \( FBV_{ac} \).

2b. \( FBQ \) has a larger impact on the inter-area mode damping ratio and frequency when the DC link power operating point is higher.

2c. The inter-area mode damping deteriorates as the bandwidth is increased for \( FBV_{ac} \) in VSC2. This is particularly true for the case of 100MW DC link power, when the damping ratio of the inter-area mode is pushed to a negative value with a \( FBV_{ac} \) of bandwidth 7Hz. In such a case, the system will become unstable.

2d. The frequency of the inter-area mode is decreased when \( FBV_{ac} \) is employed in VSC2 instead of \( FBQ \). However, variations in \( FBV_{ac} \) control settings have little impact on the inter-area mode frequency.

Test Case 3: Further Investigation on \( FBV_{ac} \)

Since it has been identified in test case 2 that the bandwidth of the AC voltage controller has the largest influence on the inter-area mode compared with all other FB type controls, this test case is chosen for further analysis in this section.

It can be observed from the two plots in Fig. 4.8 that with higher DC link operating conditions, \( FBV_{ac} \) has decreasing influence on the damping ratio but increasing influence on the frequency of the inter-area mode. This is more clearly shown in Fig. 4.9, which compares the inter-area mode movement affected by \( FBV_{ac} \) (bandwidth=1-30Hz) with respect to different DC link operating points. Other tests show that the effect of \( FBV_{ac} \) on the damping of inter-area mode also depends on its location. This is demonstrated in Fig. 4.10 by comparing the effect of \( FBV_{ac} \) (bandwidth=1-30Hz) in VSC1 (sending end) and VSC2 (receiving end) of 100MW DC link power.
The effect of $FBV_{ac}$ in VSC terminals on inter-area mode is comparable to the effect of fast exciters in the synchronous generators [93]. Continuing with the conclusions in the previous test cases, some characteristics of the $FBV_{ac}$ can be summarized as:

3a. With an increasing DC link power, the impact of $FBV_{ac}$ on the damping ratio of the inter-area mode decreases while the impact on the frequency of the inter-area mode increases as shown in Fig. 4.9.

3b. The location of the $FBV_{ac}$ has a strong impact on the damping ratio of the inter-area mode, which is similar to the effect of one fast exciter in one of the four generators stated in [93]. A fast $FBV_{ac}$ at the receiving area (VSC2) reduces the damping of the inter-area mode, while one at the sending area (VSC1) improves
the damping (Fig. 4.10). This general behaviour agrees to a certain extent with the case of one fast exciter and three slow exciters in the four generator test system of [93]. However, in [93], it is stated that in the case of one fast exciter and three manually controlled exciters, a fast exciter in the receiving area improves the damping while one in the sending area reduces the damping. This is not the case with \( FBV_{ac} \) as further tests showed that the effect of the location of \( FBV_{ac} \) does not change when the slow exciters in the generators are replaced by manually controlled exciters.

3c. The impact of the location of \( FBV_{ac} \) on the frequency of the inter-area mode is similar to the effect of one fast exciter in one of the generators [93]: A fast \( FBV_{ac} \) or exciter in the sending area increases the frequency of the mode, while one in the receiving area reduces it.

The effect of \( FBV_{ac} \) is validated by time domain simulations presented in Fig. 4.11, which compares the tie-line power responses for a three-phase 100ms self-clearing fault at bus5 considering different configurations of \( FBV_{ac} \).

\[
\begin{align*}
\text{FBV}_{ac} & \text{ employed in VSC1} \\
\text{FBV}_{ac} & \text{ employed in VSC2}
\end{align*}
\]

Fig. 4.11 Effect of \( FBV_{ac} \) control in different locations (DC link power =100MW).

Tests regarding the effect of droop gain settings on the inter-area mode are also carried out. However, in the case of a point-to-point DC link, different droop gains added to
either FF or FB type outer controllers result in very similar inter-area mode behaviour as the cases without adding the droop gain. Therefore these results have been omitted for brevity.

**DC System Effects**

The effects of VSC controls on the DC side system are reviewed by means of sensitivity analysis based on a set of simulated comparisons. In this case, the focus is put on the dynamic behaviours of the DC side voltage and the DC link real and reactive power output when they are affected by different VSC controls. The dynamic performance of the control schemes is compared for both parameter step change events and the three-phase fault (same type and location of the fault as before). The results are presented in Fig. 4.12 where (a)-(d) show the step responses and (e)-(h) show the AC fault responses. From this comparison, the following conclusions can be drawn:

**DC side voltage**

The dynamic behaviour of DC link voltage is mainly affected by $FBV_{dc}$ or droop control. Other controls show limited impact on the DC voltage responses. Effects of $FBV_{dc}$ configuration are illustrated by Fig. 4.12 (a) and Fig. 4.12 (e). The effect of droop gain is shown in Fig. 4.12 (b) and Fig. 4.12 (f). As the DC line impedance is not very large, even though different droop gain settings are applied in each case to both VSC1 and VSC2, the initial and resulting DC voltage values are almost the same for the different droop gain values. Steady-state error is seen with droop control for step changes. Larger droop gain results in slightly smaller DC voltage oscillations following the AC fault. A comparison of $FBV_{dc}$ ($bandwidth=10Hz$) and droop control with droop gain of 10 cascaded on a $FBP$ with $bandwidth=10Hz$ is given in Fig. 4.13, where droop control gives better voltage control under the AC fault.

**Real Power and Reactive Power**

The DC link real and reactive power outputs are mainly affected by VSC PQ controls. This is illustrated by Fig. 4.12 (c) and Fig. 4.12 (g) for real power responses and Fig. 4.12 (d) and Fig. 4.12 (h) for reactive power responses.
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Note that, in Fig. 4.12 (h), during the AC system fault, $FFQ$ results in large oscillations. This is due to the errors in PLL causing $v_q$ to be non-zero during an AC system fault, and thus the disturbance terms $v_q i_q$ and $v_q i_d$ in Fig. 4.2 and Fig. 4.3 are no longer zero. However, as $v_q i_q$ ($i_q \approx 0$) is much smaller than $v_q i_d$, larger oscillations appear with $FFQ$ control for the AC system fault event. To analyse this further, the disturbance terms also affect FF and FB type PQ control differently during the AC system fault event. Assuming an ideal inner current loop and $v_q$ to be non-zero after an AC fault, according to the block diagram transfer functions shown before, we have:

**FF type PQ control:**

$$\frac{P^*}{v_d} \times v_{do} + v_q i_q = P, \quad \frac{Q^*}{-v_d} \times (-v_{do}) + v_q i_d = Q$$ \hfill (4.12)

**FB type PQ control:**

$$P^* \frac{skp_{p} v_{do} + ki_{p} v_{do}}{s (kp_{p} v_{do} + I) + ki_{p} v_{do}} + v_q i_q \frac{s}{s (kp_{p} v_{do} + I) + ki_{p} v_{do}} = P$$ \hfill (4.13)

$$Q^* \frac{-skp_{q} v_{do} - ki_{q} v_{do}}{s (1 - kp_{q} v_{do}) - ki_{q} v_{do}} + v_q i_d \frac{s}{s (1 - kp_{q} v_{do}) - ki_{q} v_{do}} = Q$$ \hfill (4.14)

It can be observed from the above equations that the disturbance terms $v_q i_q$ and $v_q i_d$ affect FF type control output power directly during the AC system fault event. However, they are attenuated in the case of FB type control by the outer controller. This is because FF type PQ control relies on the assumption that $P = v_d i_d$ and $Q = -v_d i_q$ which requires a correct operation of the PLL and is not able to “see” variations in $v_q$. FB type PQ controls are based on the fuller power equations, and thus they are able to modify their current references when the disturbance terms vary. A more comprehensive comparison of FF and FB type PQ controls is addressed in [57].
Fig. 4.12 DC side dynamic response comparison of different control schemes for step change (a-d) and AC system fault (e-h) events.
4.5. Test Based on Dynamic GB System

In this section, the test AC system is replaced by the dynamic GB system developed in Chapter 3 and shown in Fig. 4.14. The identifications based on the generic two-area system are further tested.

Fig. 4.14 “Dynamic GB system” with embedded VSC HVDC link.
In this case study, all generating units utilize the detailed sixth order synchronous generator model, except the wind generator which is modelled as a windfarm connected through a converter to the grid. Standard IEEE exciters are used for different generation types, and the designed PSSs are equipped. Governors are not included for this study as only electromechanical transients are of interest. A number of circumstances (e.g. different dispatch of generations, different loadings etc.) may cause problems in such a system. To illustrate this, the system is further stressed by adjusting the distribution of the load in different areas, creating a situation where more power is transferred from the North to the South without any thermal branch overloads. This represents the situation where Scotland is exporting power for the heavy load demand in the England network, which will push the system to reach its stability margin.

For a heavily stressed condition, the system model has a 0.47 Hz low frequency inter-area electromechanical mode [94]. Fig. 4.15 highlights this unstable eigenvalue with damping ratio of -0.5%.

![Inter-area mode shape plot](image)

Fig. 4.15 Eigenvalues of the stressed dynamic GB system (eigenvalues with small negative parts and positive frequencies only) and mode shape plot.

The normalized right eigenvector of inter-area mode, corresponding to rotor speeds, is also given in Fig. 4.15 to show the grouping of generators in inter-area oscillation (mainly between G1-G4 and the rest of the generators). Based on the mode shape plot,
an embedded VSC HVDC link is modelled, between bus 4 and 14, to connect the two generator groups. This represents a future eastern link proposed for the GB grid [95]. The power is transferred in the direction from VSC1 to VSC2 (North to South) with a total installed capacity of 1GW. The DC cables of approximately 400km are modelled using four lumped equivalent $\pi$ sections for each one.

There are in total more than 230 state variables in this integrated system, including mainly the states in the synchronous generator models and controls, as well as the states in the VSC HVDC converters and controls. Due to the size of the whole integrated system, it is considered efficient to only calculate a specific set of eigenvalues with certain features of interest. The Arnoldi method is applied to solve and track the partial eigenvalues for the integrated system around a reference point with small negative real part and frequencies of 0.1-0.7Hz. The targeted critical modes are dominantly participated by the speed state variables in the majority of the synchronous generators in the system. The focus is put on the damping ratio of the inter-area mode in this case. A series of tests are performed as listed in Table 4.6, with the resulting damping ratios calculated. Time domain simulations are also provided to support the eigenvalue analysis with a self-clearing 60ms three-phase fault at bus 24.

A test comparing FF and FB type PQ controls in the VSC with different DC link operating conditions has been carried out in this case. Both types of PQ controls result in very similar inter-area mode damping with an increasing DC link power, which is different from the case of the two-area system presented before. As the AC system voltages are more stable due to the highly meshed nature of the representative GB system, the FF type PQ controls act in a manner equivalent to very fast FB type PQ controls. It is observed in Table 4.6 that the system moves from unstable ($\xi =-0.42\%$) to marginal stable ($\xi =0.08\%$) with increasing DC link power from 100MW to 900MW this time in both cases. Such results are validated in Fig. 4.16, which compares the effect of FF and FB type controls as well as the effect of different DC link operating points on the tie-line 8-10 power responses following the AC fault. It should be noted that what would typically be considered a satisfactory damping (i.e. the resultant peak
power deviation to be reduced fewer than 15% of its value at the outset within 20s) has not been achieved in this case.

Table 4.6 Inter-area mode damping ratio for case studies in GB system.

<table>
<thead>
<tr>
<th>Test cases with control settings in test case 1</th>
<th>DC link power</th>
<th>Inter-area mode $\xi$ %</th>
</tr>
</thead>
<tbody>
<tr>
<td>FF and FB type controls</td>
<td>100MW</td>
<td>-0.42%</td>
</tr>
<tr>
<td></td>
<td>500MW</td>
<td>-0.15%</td>
</tr>
<tr>
<td></td>
<td>900MW</td>
<td>0.08%</td>
</tr>
<tr>
<td>Fast $FBV_{ac}$ in VSC1</td>
<td>500MW</td>
<td>3.12%</td>
</tr>
<tr>
<td>Slow $FBV_{ac}$ in VSC1</td>
<td>500MW</td>
<td>-0.01%</td>
</tr>
<tr>
<td>Fast $FBV_{ac}$ in VSC2</td>
<td>500MW</td>
<td>-0.51%</td>
</tr>
<tr>
<td>Slow $FBV_{ac}$ in VSC2</td>
<td>500MW</td>
<td>-0.19%</td>
</tr>
</tbody>
</table>

As $FBV_{ac}$ is found to have more impact on the inter-area oscillation than other VSC controls, a better and satisfactory damping effect may be achieved. The tracked inter-area mode damping ratios with $FBV_{ac}$ in both VSCs of the DC link validate aforementioned conclusion 3b before — A fast $FBV_{ac}$ in the receiving area (VSC2) reduces the damping of the inter-area mode while a faster $FBV_{ac}$ in the sending area (VSC1) improves the damping, as listed in Table 4.6. This is further shown in the time domain simulations for the AC fault in Fig. 4.17. In both cases, the VSC controlled bus voltage is improved with faster $FBV_{ac}$. However, only a faster $FBV_{ac}$ in VSC1 increases
the system inter-area mode damping, and thus stabilizes the post fault system. The opposite (though the effect is reasonably small) is seen when $FBV_{ac}$ is employed in VSC2. Care must be taken though when using $FBV_{ac}$ with a very high bandwidth as it may cause the connected AC system to become unstable in some circumstances.

![Graphs showing system responses with $FBV_{ac}$ control in VSC1 and VSC2.](image)

Fig. 4.17 (a) System responses with $FBV_{ac}$ control in VSC1 and (b) System responses with $FBV_{ac}$ control in VSC2.

### 4.6. Effect of MTDC with Different Droop Controls

So far the effects of a point-to-point VSC HVDC link have been discussed in detail. Further investigation of the assessment of VSC HVDC control strategies will consider the case of a multi-terminal DC (MTDC) grid. The multi-terminal operation is anticipated as a reliable solution for future grid interconnections such as the European
SuperGrid. Different control schemes adopted in a VSC MTDC system will change the power injections into the connected AC grid and thus affect its dynamic performance. Further analysis in this section compares the typical control strategies used in a four-terminal DC system for windfarm and onshore connections based on the dynamic GB system which is also a possible future scenario for the GB grid. A series of control strategies are created for the MTDC grid, including the typical voltage margin control and different droop control settings. The DC system power sharing and the corresponding effects on the AC system are demonstrated.

MTDC Grid Control

A four-terminal DC grid is integrated to the dynamic GB model connecting one windfarm and three onshore buses. The power flow directions at the original operating point are also shown in Fig. 4.18.

Fig. 4.18 Diagram for the integrated GB system and MTDC grid.

Three different types of control scenarios are designed for the GSVSCs and their $V_{dc}-P$ characteristics as illustrated in Fig. 4.19. Control scheme 1 adopts a two-stage voltage
margin control to allow the role of DC voltage regulation to be transferred to other converters when the DC voltage regulating converter reaches its power limit (e.g. from GSVSC3 to GSVSC2). Enhanced DC system reliability is achieved in comparison to the conventional one-stage voltage margin control due to a reduced reliance on communications. However, at each instant, there is still only one converter station responsible for the DC voltage regulation.

Control scheme 2 is a standard $V_{dc}$-$P$ droop control, which allows a certain amount of variations in the DC voltage for each converter, and hence all converters share the responsibility of voltage regulation. During operation, the converters’ power set-points are adjusted by the measured DC voltages according to the droop lines. The slope of a droop line indicates the degree of sensitivity of a converter’s output power to its DC voltage variations.

Control scheme 3 is a combination of the concepts used in the previous two control schemes where essentially a two-stage voltage droop control is presented. The deadband is introduced in GSVSC2 and GSVSC3 to allow them to operate in constant power control mode for normal operation, so that their output power will be unaffected during small system disturbances. However, they will still be able to return to voltage droop control mode when the measured DC voltage exceeds the constant power operating limits ($V_{low}^*$ and $V_{high}^*$).

The role of the windfarm side VSC is similar to a slack bus in the AC grid. It is there to absorb all the power generated by the windfarm and also provide a reference frequency for the wind turbines. To do so, the WFVSC is configured to maintain a constant voltage at the PCC bus of the windfarm, and it also provides a constant frequency reference. The initial operating point of the system is that GSVSC1 and the WFVSC are injecting 1.4GW and 1.7GW power, respectively, into the DC grid. GSVCS2 and GSVCS3 each receive 1.2GW and 1.9GW from the DC grid. Detailed controller parameters are given in Table 4.7. The value $K_{slope} = 15$ is selected to provide an appropriate trade-off between the steady-state DC voltage error, the response speed, the dynamic performance and the MTDC stability [96]. Since the purpose is to compare the performance of different MTDC control schemes, the same value is applied in all
control strategies. The DC lines are operating at ±320kV with lengths shown in Fig. 4.18.

![Diagram](image)

**Table 4.7 Data for MTDC control schemes (Fig. 4.19).**

<table>
<thead>
<tr>
<th>Control Scheme</th>
<th>Grid Side Converters</th>
<th>Grid Side Converters</th>
<th>Grid Side Converters</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>GSVSC1</td>
<td>GSVSC2</td>
<td>GSVSC3</td>
</tr>
<tr>
<td>Voltage Margin</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$V_{dc, high}$*</td>
<td>1.035 p.u.</td>
<td>1.02 p.u.</td>
<td>$V_{dc}$ set from load flow</td>
</tr>
<tr>
<td>$V_{dc, low}$*</td>
<td>0.96 p.u.</td>
<td>0.97 p.u.</td>
<td></td>
</tr>
<tr>
<td>Droop</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$K_{slope}$ = 15</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Droop with dead-band</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$V_{high}$*</td>
<td>1.015 p.u.</td>
<td>1.015 p.u.</td>
<td>$K_{slope}$ = 15</td>
</tr>
<tr>
<td>$V_{low}$*</td>
<td>0.97 p.u.</td>
<td>0.97 p.u.</td>
<td></td>
</tr>
</tbody>
</table>

* operating point $P_{ref}$ values are obtained from load flow results

**Power Sharing in DC Grid**

The power sharing in the DC grid can be affected by the droop gains. A brief explanation is provided here. For DC network power flow, assuming a monopolar,
symmetrical grounded DC grid, the system can be described using the following equations:

\[ I_{dc} = Y_{dc} U_{dc} \]  
\[ P_{dc} = 2U_{dc} I_{dc} \]  
\[ Y_{dc} U_{dc} - \frac{P_{dc}}{2U_{dc}} = 0 \]

where \( Y_{dc} \) is the DC network admittance matrix. When converters are under droop control scheme, there is one more constraint they have to follow:

\[ P_{aci} = K_{slopei} (V_{aci} - V_{aci}^*) + P_{aci}^* \]

where superscript * stands for the reference point. The above equations (4.17) and (4.18) can be solved iteratively with a Newton-Raphson method to calculate the voltages on all DC buses. Thereafter, the power injections at the GSVSCs terminals are calculated. Droop gain \( K_{slopei} \) can be adjusted until the power injection at the terminal meets the requirement of the connected AC system if provided. By this means, the value of \( K_{slopei} \) can be determined for droop control schemes. Values like the DC line impedances and converter losses are normally invariable. Then the desired AC grid power injection scenario is usually achieved by properly designing the droop gain settings.

**Simulation Studies for Wind Power Injection**

A sudden 500 MW rise of wind power injection to the DC grid is firstly simulated as an event for this case study, investigating the AC side power injection affected by different MTDC control schemes depicted in Fig. 4.19. This might, for example, represent the extreme case of several strings in a windfarm being switched in. The responses of the key parameters in both the DC and the AC sides of the system are presented under the three MTDC control schemes.

**DC System Responses**

Fig. 4.21 (a) shows the output power from the three GSVSCs under different control schemes, and the resulting power flow shows very different power sharing scenarios. In
order to demonstrate clearly how the GSVSCs react to the injected wind power, Fig. 4.20 is provided with indexes (1) to (3) indicating the sequence of the actions taken in the converters. The total power change in each terminal during the process is also illustrated.

Fig. 4.20 DC grid power change for different control schemes.

Fig. 4.21 Simulation results for 500 MW wind power injection.
For voltage margin control, the GSVSCs react to the wind power injection in the following sequence: (1) the injected wind power is firstly transferred by GSVSC3 which is in constant DC voltage control. (2) The duty of DC voltage regulation is then changed to GSVSC2 when GSVSC1 turns into constant power control mode after reaching its maximum power limit. (3) Since GSVSC2 is capable of transferring the rest of the injected wind power, GSVSC3 remains in constant power control mode and its output power is unaffected after the event.

Standard droop control has the characteristic that all converter stations participate in DC voltage control, and hence all GSVSCs in the DC grid react to share the injected wind power. Therefore, the GSVSCs modify their power transfer simultaneously (Fig. 4.20) to reach a new stable operating point. The amount of power shared by each converter is affected by its own droop gain, as discussed in the previous section. This can be properly designed in order to achieve a desired power injection scenario.

For control scheme 3, where a dead-band is introduced into the droop control, GSVSC1 and GSVSC2 were initially in constant power control mode. Similar to the voltage margin control, the GSVSCs react to the wind power injection in the following sequence: (1) GSVSC3 adopts the standard droop control, and it changes its operating point to transfer the wind power until it reaches its maximum power limit. (2) After GSVSC3 enters its constant power control mode, the other two GSVSCs turn into droop control mode, and they start to modify their operating points and share the rest of the injected wind power. The amount of power distributed to GSVSC1 and GSVSC2 again is affected by their droop settings. Fig. 4.21 (c) gives the behaviours of the DC side voltages. It is clear that, droop controls, which give an allowance for DC voltage variations, end up with more smooth DC voltage transients in comparison with voltage margin controls which force a constant DC voltage.

*Effect on AC System*

The resulting power flow scenarios in the DC lines lead to different AC system behaviours. Fig. 4.21 (b) shows the resulting injection bus voltages. It is generally
observed that the magnitude of the transient overshoot is proportional to the amount of power change ($\Delta P$) in the bus (e.g. for injection bus 7, a larger voltage transient is seen when it has a larger $\Delta P$). The magnitude of the oscillations is small here due to the small capacity of the MTDC grid in comparison with the whole AC system. However, this can grow larger when more power is transferred from the DC links into the grid.

The tie-line 10-15 power responses (Fig. 4.21 (d)) are most affected when the power injections of GSVSC2 and GSVSC3 change. However, in contrast to the DC voltage responses, the power injection scenario provided by voltage margin control leads to a smaller power oscillation in the tie-line. This is mainly due to the fact that the total amount of power change in the whole DC grid is the smallest under the voltage margin control (Fig. 4.20).

**Simulation Studies for AC System Fault**

This case study investigates the integrated system behaviour for AC side events under different MTDC control schemes. A 100ms self-clearing three-phase fault is created at bus 10 and again the focus is on the responses in both the AC and the DC side of the system as presented in Fig. 4.22.

It is seen from Fig. 4.22 (a) that the power injections at the three GSVSCs are disturbed when the AC system fault occurs. The worst case scenario is seen when voltage margin control is adopted in the MTDC grid. GSVSC3 is operating at its maximum power capability which is then reduced during the AC system fault event due to a drop in the converter AC side voltage. The PLL in GSVSC3 also becomes inaccurate during the fault. Therefore, the controls in GSVSC3 become saturated for a short period of time when voltage margin control is adopted. This causes the “spike” in the resulting GSVSC3 power response. In order to keep a constant DC voltage, the voltage margin control scheme results in larger power oscillations in comparison with the other two control schemes.

The ability of smooth DC voltage control for a droop control scheme is again shown in Fig. 4.22 (c). A better DC voltage response is given when all GSVSCs are in standard droop control mode. The other two control schemes result in larger overshoot in the DC
voltages. However, the AC side injection bus voltages, which should be affected by the DC voltage variations, turn out to be very similar. This is because the differences in the DC side responses are too small (fast) to be noticed by the AC side and the generators connected at the injection buses are also contributing in voltage regulation. Therefore, the injection bus voltages are not significantly affected by the control schemes adopted in the MTDC grid under AC faults. As a result, the injection bus voltage responses coincide as shown in Fig. 4.22 (b), and the tie-line power flow is also not affected (Fig. 4.22 (d)) for the same reason.

The best MTDC control strategy thus varies depending on the specific structure of the connected AC system, as well as the requirement on the power injection at each terminal, and the transient and static performance of the DC system. This requires a full mathematical model of the integrated system to optimize the power flow based on the provided requirements from the AC grid.

![Fig. 4.22 Simulation results for AC system fault.](image-url)
4.7. Conclusion

This chapter provides a systematic comparison of the effects of VSC HVDC controls on the dynamic behaviour of an AC/DC system. Investigations have been carried out on typical outer voltage and power control schemes for a single converter, as well as the MTDC control strategies for multiple converters. The effect of VSC outer controller parameter settings are analysed via modal analysis techniques, and are validated through transient simulations. It has been particularly shown that the VSC outer loop control settings can have a significant impact on AC system inter-area oscillation damping. Therefore, well-tuned outer controllers might be able to damp the system oscillations appropriately such removing the need for additional supplementary POD controllers completely, in particular if these are local POD controllers, or to inform the design of additional wide area monitoring based POD if these are to be installed. Typical conclusions obtained from the results are illustrative for a very standard two-area system and a system based on reality, and they are therefore helpful for providing insights and understanding the possible influences brought by DC controls on the AC dynamics. For VSC outer controls in a parallel VSC HVDC link, typical conclusions can be summarized as:

i. The operating point of the DC link (power flow) and the AC voltage control in VSCs have larger influences on the AC system inter-area oscillation than other VSC controls. For an embedded VSC HVDC link (in parallel with AC tie-lines), if FF type PQ controls are used, it normally increases the damping of the inter-area mode at higher power flow. However, when FB type PQ controls are used, their effects on the damping of inter-area mode may depend on the system structure.

ii. Additionally, FBVac in the receiving area of an embedded VSC HVDC link with higher bandwidth reduces the damping of the inter-area mode, while one in the sending area (VSC1) improves the damping. Varying the bandwidth of FBVac has less influence on the damping ratio of the inter-area mode at higher DC link power. However, the FBVac bandwidth variation has larger influence on the frequency of the inter-area mode at higher DC link power.
For different MTDC control strategies employed in a four-terminal DC system, the key identifications can be summarized as:

i. From the perspective of DC grid power change event, the adopted MTDC control scheme can significantly affect the DC power flow and thus leads to different corresponding AC system responses. The power injected at each terminal of a MTDC grid can be estimated by the DC grid load flow, taking into consideration the influences of the adopted MTDC control scheme in order to achieve an optimal power injection for the connected AC grid.

ii. In terms of AC system fault events, the effect of MTDC control scheme is mainly reflected in the transient behaviours of the DC side system. The AC system voltages and tie-line power flows are not significantly affected when different, reasonably tuned MTDC control schemes are adopted in this case.
Chapter 5. Potential Interactions between VSC HVDC and STATCOM

This chapter analyses the dynamic behaviour of a power system with both FACTS and VSC HVDC, in particular, possible potential interactions between a STATCOM and a VSC in a point-to-point HVDC link. The investigation considers different system conditions regarding factors of electrical distances between the devices, the AC system strength, as well as possible control schemes that are typically employed in these devices. A generic linearized mathematic model of a reduced system is firstly developed, where a combined method involving relative gain array (RGA) and modal analysis is applied to identify the interactions within the plant model and the outer controllers. Potential adverse interactions are highlighted with weak AC system conditions. The identifications are further tested by creating a set of scenarios integrating both the STATCOM and VSC HVDC into the dynamic GB system. Results show a collaborative operation between the STATCOM and the closely located VSC with reasonably tuned controllers in a strong AC system.

5.1. Interactions in HVDC and FACTS

The Electricity Ten Year Statement shows an increased number of DC transmission interconnections being proposed for connecting windfarms sited far offshore and for reinforcement of the onshore network via undersea DC cable links. Meanwhile, as the amount of windfarm installations increases, FACTS devices like STATCOMs will be used to help wind power generation to achieve grid code compliance [97]. STATCOMs also have a potential synergy with LCC based HVDC links for reactive
power supply [20]. A natural consequence of increasing quantities of actively fast controlled devices is that these components might be located in the electrical proximity to each other, especially for a VSC based multi-terminal HVDC (MTDC) grid in the future. It is therefore important to understand their control interactions. This chapter considers the particular case of a STATCOM, installed perhaps as part of a windfarm and located close to a VSC-based HVDC link. Valuable work regarding interaction studies has been carried out in many aspects. Studies regarding concurrent operation of multiple FACTS devices or FACTS devices and conventional LCC HVDC links indicate that there exist potential interactions [98-101]. Many methods have been proposed and applied in order to study these interactions. The concept of induced torque is introduced in [100] to study the interactions between power system stabilizers and FACTS stabilizers, and their controller tuning effect on the overall system is analysed in [102]. Furthermore, the RGA [103] method has been shown in [99, 104] to be suited to quantify the interactions in power system steady-state and dynamic studies. It was also suggested in [98] that modal analysis can be used to highlight how modifications in one FACTS controller can affect another. Several factors, including the electrical distances between the devices and the AC system short circuit ratio, have been identified as influencing the degree of interaction. However, the interactions between VSC HVDC links, which use substantially different control to LCC HVDC, and FACTS devices have not yet been thoroughly investigated. The cascaded control structure in a VSC HVDC means that interaction with a STATCOM can occur through multiple control structures and cannot completely be identified through a single conventional method. It is therefore reasonable to propose a combined method that utilizes RGA to quantify the plant model interactions and modal analysis to illustrate the outer controller interactions. Different types of VSC control strategies are also considered since this may affect the degree of controller interactions. The study is initially carried out in a small test system to facilitate physical understanding of interactions.
Following this, a set of scenarios is then created using the dynamic equivalent model of GB system to validate findings.

5.2. STATCOM Model for Stability Studies

A STATCOM is a fast acting power electronic device based on VSCs, which can act as either a source or a sink of reactive power to an electricity network. It is a shunt device of the FACTS family to regulate voltage at its terminal by controlling reactive power flow. It is normally installed to support electricity networks that have a poor power factor and often poor voltage regulation, achieving power system dynamic compliance between lead/lag 0.95 power factor. By keeping a high power factor in the system, the transmitting current can be reduced for less energy loss in the transmission system. The voltage source is created from a DC capacitor, and thus a STATCOM has very little inherent active power capability. However, this can be enhanced by connecting suitable energy storage devices (e.g. batteries, pumped storage, etc.) to the DC capacitor. A typical structure is illustrated in Fig. 5.1, showing also the coupling transformer and reactor.

![STATCOM model](image)

**Fig. 5.1 STATCOM model (a) with δ-PM control (b) V-I characteristic.**

The typical phase angle (δ) and the modulation index (P_M) [50] control structure for STATCOM is also presented. Please see Chapter 2 for detailed description of this control (i.e. power angle control). For power system voltage and angle stability
studies, the STATCOM model can be expressed by power balance and voltage conversion equations. After linearization, the equations are:

\[
\Delta \dot{V}_{dc} = A \Delta V_{dc} + B \frac{\Delta V}{\Delta \delta} = \frac{V^2 G - V \delta_b G \cos(\delta - \delta_0) + B \sin(\delta - \delta_0)}{-C V_{dc}^2} \Delta V_{dc}
\]

(5.1)

\[
+ \left[ \begin{array}{c}
2G V - V \delta_b G \cos(\delta - \delta_0) - V \delta_b B \sin(\delta - \delta_0) \\
-V G \cos(\delta - \delta_0) - V B \sin(\delta - \delta_0) \\
V \delta_b G \sin(\delta - \delta_0) - V \delta_b B \cos(\delta - \delta_0)
\end{array} \right]^T \\
\frac{C V_{dc}}{C V_{dc}} \\
\frac{C V_{dc}}{C V_{dc}} \\
\frac{C V_{dc}}{C V_{dc}}
\]

\[
V = \frac{\sqrt{3}}{8} V_{dc} \times P_M
\]

(5.2)

where the parameters are as specified in Fig. 5.1. The controller limits are defined based on the controller current limits (e.g. IGBT current limits), and the effect of transient performance needs to be factored into the controller tuning. However, the limits of the phase angle and the modulation index do not necessarily limit the actual current. According to the V-I characteristic, the modulation index limits \( P_{M, max} \) and \( P_{M, min} \) can be calculated as:

\[
P_{M, max} = \frac{2 \sqrt{2}}{\sqrt{3}} \times \frac{V_{ref} + K_{slope} I_{max}}{V_{dc, ref}}
\]

(5.3)

\[
P_{M, min} = \frac{2 \sqrt{2}}{\sqrt{3}} \times \frac{V_{ref} + K_{slope} I_{min}}{V_{dc, ref}}
\]

The phase shift limits \( \delta_{max} \) and \( \delta_{min} \) need to be derived by calculating the steady-state equation for the control system at \( I_{max} \) and \( I_{min} \) [50].

### 5.3. Generic Interaction Study

The VSC HVDC model described in Chapter 2 is used here with the developed STATCOM model. In order to quantify the interactions between a STATCOM and a VSC in the HVDC link, a reduced test system was established with only a VSC
HVDC link and a STATCOM interconnected through a line with adjustable impedance (Fig. 5.2). This removes unnecessary detail that could clutter and obscure results. A voltage source behind impedance is used to represent an AC network. The system strength can be parameterized by varying the value of the impedance, and thus the short circuit ratio (SCR). The VSC controls its injection current to the system; while in turn, the system provides the reference bus voltage (bus 2) to the phase locked loop (PLL) and the VSC. The STATCOM communicates with the AC system through voltage exchange.

The intention behind using a reduced system model is to obtain general interactions before applying the models to a large and specific test system. Our method is to use RGA to analyse the interactions in the plant model, as the method does not depend on the controllers. Outer controller interactions can be investigated through modal analysis techniques.

**RGA for Plant Model**

Since firstly proposed by Bristol [103], RGA provides a measure of interactions and is normally used as a tool for multi-input multi-output (MIMO) system optimal input-output pairing. However, here it is possible to consider it as a way to quantify the degree of interaction between the plant model of the STATCOM and VSC.

Fig. 5.2 Reduced system model for generic interaction study.
One way to calculate the RGA of a MIMO system is to use the steady-state gain matrix obtained from system model equations. Let \( u_j \) and \( y_i \) denote an input-output pair of a plant \( G(s) \), the relative gain can be expressed as the ratio of two extreme cases [45]:

\[
\lambda_{ij} = \frac{\frac{\hat{c} y_i}{\hat{c} u_j}}{\frac{\hat{c} y_i}{\hat{c} u_j}} = \frac{g_{ij}}{g_{ij}} = \left[ G_{ij} \times \left[ G^{-1} \right]_{ji} \right] = \left[ g_{ij} \right]^{\text{all-other-loops-open}} \frac{g_{ij}}{g_{ij}}^{\text{all-other-loops-closed}} = \left[ G \right]_{ij} \times \left[ G^{-1} \right]_{ji},
\]

(5.4)

The RGA element \( \lambda_{ij} \) measures the influence of all other variables on the gain between input \( u_j \) and output \( y_i \). If \( \lambda_{ij} = 1 \), all the other control loops have no impact on the control pair \( u_j \) and \( y_i \), and this is the case where no interaction exists. Thus \( \lambda_{ij} \neq 1 \) indicates there are interactions between the other control loops and the selected control pair. The closer the value of \( \lambda_{ij} \) is to the unity, the smaller the interaction is. These important properties of RGA (summarized in [45, 104]) are used for evaluating the degree of interaction in this case.

To study the interactions within the plant models, the outer control loops of the STATCOM and the VSC should be removed. The resulting plant model is within the dashed square shown in Fig. 5.3 where the plant manipulated inputs and outputs are labelled. Inputs \( i_d^* \) and \( i_q^* \) are the reference dq current values in VSC2 while \( P_M \) and \( \delta \) are the manipulated inputs for the STATCOM. The outputs are the calculated results from the network which are fed back to the STATCOM and VSC2.

By linearizing the system model at an operating point, the system steady-state gain matrix can be calculated for the defined inputs and outputs. As there are four inputs and outputs, the plant model \( G(s) \) will be a 4×4 matrix with each element representing a transfer function between a corresponding input and output pair (e.g. \( g_{21} \) stands for the transfer function between input 1 and output 2). According to the definition in equation (5.4), the RGA of the four inputs and four outputs system can be derived based on equation (5.5).
When calculating the RGA from the steady-state gain matrix (frequency ‘0’), the resulting RGA for two different lengths of the interconnecting line is given in Table 5.1. The diagonal elements in bold show the corresponding control pairs where the input has dominant effect on the output. The RGA element value of ‘1’ for the control pairs of $u_1-y_1$ and $u_3-y_3$ shows that these two control pairs are not affected by any other control loops in the system. Interactions are mainly detected between the VSC q-axis current control loop $i_q^*-v_2$ and the STATCOM modulation index control loop $P_{Mr}v_3$. RGA values larger than 1 indicate that the control pairs are dominant in the system, but the other loops are still affecting the control pairs in the opposite direction. The higher the value, the more correctional effects the other control loops have on the pair. This interaction becomes more significant as the electrical distance between the VSC and the STATCOM decreases (RGA number 1.42 to 1.96).

The RGA analysis suggests interactions between VSC2 $i_q^*-v_2$ and STATCOM $P_{Mr}v_3$ in the plant models without outer control loops. However, in normal operation, outer...
control loops for the two components need to be considered. To further show how VSC and STATCOM affect each other through outer controls, a parametric analysis based on the modal analysis and transient simulations was performed.

Table 5.1 RGA results for selected inputs and outputs.

<table>
<thead>
<tr>
<th>Input</th>
<th>Line: (1+20j)Ω</th>
<th>Line: (0.5+10j)Ω</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(i_d^*)</td>
<td>(i_q^*)</td>
</tr>
<tr>
<td>(y_1):P</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>(y_2):(v_2)</td>
<td>0</td>
<td>1.42</td>
</tr>
<tr>
<td>(y_3):(V_{dc})</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>(y_4):(v_3)</td>
<td>0</td>
<td>-0.42</td>
</tr>
</tbody>
</table>

**Outer Control Interactions**

The reduced system model is also used for analysing the outer control interactions. To do this, VSC2 is configured with typical outer controls of: (1) the Feedback \(P\) and \(Q\) control and (2) the Feedback \(P\) and \(V_{ac}\) control, as described in Chapter 2. For convenience, these controls will be referred to as \(PQ\) control and \(P-V_{ac}\) control in the following text of this chapter. The other types of VSC control, such as DC voltage control or droop type control, are focusing more on the control of the DC side components rather than the AC system parameters, and they are not likely to have interactions with the STATCOM. This outer control interaction study considers the variations of system conditions in the short circuit capacity of the AC grid and the controller parameters in the electronic devices.

**VSC2 with \(PQ\) Control**

Firstly, VSC2 is configured to \(PQ\) control mode. Based on the results obtained from the RGA analysis of the plant models, significant interactions between VSC HVDC and STATCOM occur when they are closely located. Therefore, in this case, low transmission impedance (e.g. \(R=0.266Ω\) and \(X=2.645Ω\)) is considered. The focus will then be put on the strength of the AC system which is defined by the SCR as:

\[
SCR = \frac{SC \ MVA}{DC \ converter \ MW \ rating} = \frac{V_{ac}^2}{Z_{th}} \div DC \ converter \ MW \ rating
\]

- 146 -
As stated in [20], the AC system strength is classified as (1) high ($SCR > 5$), (2) moderate ($3 < SCR < 5$) and (3) low ($SCR < 3$), as the source impedance $X_s$ in Fig. 5.2 varies. For this study, a weak AC system with $SCR = 1.5$ and a strong AC system with $SCR = 10$ are assumed to represent two extreme system strength conditions.

The method utilizes a parametric analysis regarding different system and controller configurations. Modal analysis was used in support of the time domain simulations to show how those critical modes are affected under different controller settings. The proportional and integral gains of the STATCOM $P_M$ control (Fig. 5.1) are configured to be $k_p$ and $k_i = ck_p$ ($c = 5$). This form makes the variations in the STATCOM controller parameters easier for the case studies.

Modal analysis is firstly applied to the reduced system model with both a weak and a strong AC network. For each system configuration, the gain in the STATCOM $P_M$ control is increased from 0.1 to 1 with a step of 0.1. All the system modes are monitored each time during the process, and those that are affected by the gain change are recorded. However, since some system modes are influenced by more than one state variable in the model, it is necessary to see the contribution of each state variable for a particular mode that is affected during the process of the controller’s gain change. This is achieved by calculating the participation factors of the system state variables for these modes. The relative participation of the states in a mode can be weighed, and thus the interactions of the state variables are shown.

The trajectories of system eigenvalues for the parametric analysis are plotted in Fig. 5.4 and Fig. 5.5 for strong and weak AC systems respectively. The modes that are significantly affected (modes with obvious movement trajectory) are highlighted with labels in the two figures. The participation factors of the key system state variables related to the labelled modes are also given in Table 5.2 and Table 5.3, for strong and weak AC systems respectively. In this case, only selected state variables with significant contributions (participation factor $> 0.1$) in at least one of the critical modes are listed.

For a strong AC system, as shown in Fig. 5.4 and Table 5.2, the controller gain ($k_p$) increase in the STATCOM only has a small effect on one system mode (Mode 1) on
the negative real axis, and it is dominantly participated by the STATCOM $P_M$ control state variable. A strong AC system provides a firm AC voltage which weakens the degree of interaction between the STATCOM and VSC HVDC. However, in the case of a weak AC system, the network voltage is mainly controlled by the STATCOM. Variations in the STATCOM $P_M$ control parameters can therefore affect a number of system modes as shown in Fig. 5.5. It is seen that the increase of $k_p$ in the STATCOM does not only affect its own mode (Mode 5 which is dominantly participated by STATCOM $P_M$ control state), but also four other modes which involves state variables of the outer controllers in the VSC HVDC link and the PLL, as presented in Table 5.3.

![Fig. 5.4 Root loci of system eigenvalues with STATCOM voltage controller gain varied from 0.1 to 1 with a strong AC network.](image)

![Fig. 5.5 Root loci of system eigenvalues with STATCOM voltage controller gain varied from 0.1 to 1 with a weak AC network.](image)

<table>
<thead>
<tr>
<th>Key State Variables</th>
<th>Participation Factor (Normalized)</th>
</tr>
</thead>
<tbody>
<tr>
<td>STACOM $P_M$ controller state</td>
<td>0.99</td>
</tr>
</tbody>
</table>

*aother state variables with participation factor less than 0.1 are NOT listed

1 A mode on the negative real axis corresponds to a non-oscillatory mode that decays — the larger its negative magnitude, the faster the decay.
Table 5.3 State variables participation factor for the affected modes.

<table>
<thead>
<tr>
<th>Key State Variables</th>
<th>Participation Factor (Normalized)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mode 1</td>
</tr>
<tr>
<td>VSC2 P controller state</td>
<td>0.29</td>
</tr>
<tr>
<td>VSC2 Q controller state</td>
<td>0.18</td>
</tr>
<tr>
<td>VSC2 PLL controller state 1</td>
<td>0.13</td>
</tr>
<tr>
<td>VSC2 PLL controller state 2</td>
<td>0.018</td>
</tr>
<tr>
<td>STACOM δ controller state</td>
<td>0.37</td>
</tr>
<tr>
<td>STACOM P_M controller state</td>
<td>0.012</td>
</tr>
<tr>
<td>VSC1 Vdc controller state</td>
<td>0</td>
</tr>
</tbody>
</table>

*other state variables with participation factor less than 0.1 are NOT listed

Time domain simulations were also performed to validate the results obtained from the eigenvalue analysis. Comparisons between the system responses for both weak and strong AC system strengths when subjected to a three-phase AC short circuit fault at bus 5 for 100ms are given in Fig. 5.6, where the STATCOM P_M control gain adopts \( k_p = 0.5 \) and \( k_p = 2.5 \).

![Fig. 5.6 Comparison of system dynamic responses with a strong (left) and a weak (right) AC system.](image-url)
According to the simulation results, the controller parameter change in the STATCOM only affects its own output voltage with a strong AC system. The power and PLL responses in the VSC2 are not affected as expected from the previous modal analysis. However, when the AC system is weak, \( k_p \) change in the STATCOM affects the network voltage and thus the dynamic behaviour of VSC2 and the PLL, as shown by the figures in the right column of Fig. 5.6. The results in this case suggest that the interaction between the STATCOM and VSC2 is more significant when the connected AC system is weak. In other words, the controls in the two components can more easily affect each other when they are not decoupled by a strong AC system. However, even in the case of a strong interaction, variations in the STATCOM voltage control do not worsen significantly the dynamic performance of VSC2 \( PQ \) control nor that of the PLL in this case.

It is claimed in [105] that PLL has difficulties in reference angle tracking when the connected AC system is weak. This can affect the performance of the outer PQ controls in VSC2 and potentially the STATCOM which interacts strongly with the VSC in such a system condition. Therefore, further tests consider the effect of a parameter change in the VSC HVDC. This is demonstrated by increasing the bandwidths of the PQ control loops in VSC2 (see Chapter 4 for details on bandwidth variations) for weak AC system connection. The comparison is presented in Fig. 5.7 with the same 100ms AC fault at bus 5 each time.

According to the comparison given in Fig. 5.7, it can be observed that the STATCOM \( P_M \) control dynamic performance is improved when the bandwidth of the \( P \) control in VSC2 is increased (from 5-15Hz). However, further increase of the bandwidth of the VSC \( P \) control leads to adverse interactions between the STATCOM and VSC2. The same bandwidth variation test is also performed for VSC2 \( Q \) control. The results show that the VSC reactive power controller only affects the dynamic behaviour of its output reactive power, but not the controllers in the STATCOM, and thus they are not presented here.

The reason for the adverse interaction is analysed. This is mainly due to the fact that the real power in the network is controlled by VSC2 and its dynamic responses vary
during the AC fault. When VSC2 $P$ control loop bandwidth is increased, its real power output response after the AC fault becomes steeper and with larger overshoots. This real power flow will charge/discharge the DC capacitor of the STATCOM causing STATCOM DC voltage oscillations. Meanwhile, as the AC system is weak, the AC voltage is mainly controlled by the STATCOM. Therefore, oscillations in the STATCOM DC voltage reflect in its AC side, thus affecting the system AC voltage. The performance of the PLL and VSC2 $Q$ control, which is very sensitive to the system voltage variations, is then deteriorated. As illustrated in Fig. 5.7, increased oscillation magnitude is observed when the bandwidth of VSC2 $P$ control is changed from 15Hz to 30Hz. On the other hand, as the variations in the VSC2 $Q$ control loop bandwidth do not affect the AC voltage control in the STATCOM, no adverse interactions occur.

Fig. 5.7 System responses with different VSC2 $PQ$ control settings and a weak AC system.
Such phenomenon can be proved by comparing the DC voltage responses of the STATCOM during the AC fault event, as presented in Fig. 5.8. With the bandwidth of the VSC2 $P$ control loop increases, the STATCOM DC voltage oscillates with larger magnitude indicating the adverse interaction between the two devices caused under such circumstances.

![Fig. 5.8 STATCOM DC side voltage responses with different VSC2 $P$ control settings.](image)

**VSC2 with $P-V_{ac}$ Control**

The above adverse interactions can be mitigated by configuring the VSC in voltage control mode. This section continues the above analysis but now VSC2 is applied with $P-V_{ac}$ control. In this configuration, the reduced network AC voltage is jointly controlled by both the STATCOM and VSC2. With an increased VSC2 $P$ control loop bandwidth, the same system AC fault event is applied and the resulting responses are provided in Fig. 5.9.

With properly tuned voltage controllers (i.e. voltage control loop with reasonable step responses), both the STATCOM and VSC2 contribute to the AC system voltage compensation by supplying reactive power in a collaborative way during a fault event in the system. Adverse interactions when $PQ$ control is employed in VSC2 do not occur in this case, as the system voltage is not worsened by the high bandwidth $P$ control loop. However, it should be noted that as both devices are controlling the system voltage and are closely located, their voltage references need to be properly parameterized depending on the required local power flow.
5.4. Test on Dynamic GB System

To verify the interactions identified in the reduced model, the STATCOM and VSC models are applied to the dynamic GB system developed in Chapter 3. A set of scenarios regarding different electrical distances and control strategies was created for testing. However, the SCR in such a multi-machine system with no extremely weak transmission lines is usually high, and thus the interaction between the STATCOM and VSC HVDC is expected to be small.

A VSC HVDC line is integrated to the AC system connecting bus 2 and bus 10, carrying 500MW power flow. VSC1 is configured to regulate the DC voltage and the switchable PQ control and P-\(V_{ac}\) control are adopted by VSC2. A 225 MVA STATCOM is also added to the system at the locations illustrated in Fig. 5.10.
investigation is carried out by considering different STATCOM locations and VSC HVDC control strategies.

Fig. 5.10 Dynamic GB system with VSC HVDC link and FACTS.

Case Study 1 - Different STATCOM Locations

The selected locations are likely to have wind power injections or LCC HVDC terminals where a STATCOM might be installed. The STATCOM attempts to maintain a constant voltage of 1 p.u. at its connected bus. The converter at the receiving end of the DC link (VSC2) is in PQ control mode that delivers a constant 500 MW active power from bus 2 to bus 10, while keeping the reactive power to zero. The STATCOM is connected sequentially to three buses (10, 12, and 26). For the first location, the STATCOM is closely coupled with the receiving end VSC, as they are both trying to control either the voltage or the power of bus 10. The second and the third locations are considered as loosely coupled conditions for the VSCs and the STATCOM. A 100ms three-phase short circuit fault is applied at bus 1 in the AC grid, and the system responses are monitored for different STATCOM locations. The comparison of the responses is presented in Fig. 5.11.
In Fig. 5.11 (a), the voltage variations at bus 10 are significantly better damped when the STATCOM is connected to the bus 10. When the STATCOM is placed at the other two loosely coupled locations, its effect on the bus 10 voltage becomes much smaller. As shown in Fig. 5.11 (b) and (c), the VSC controlled real and reactive power responses are only affected by the STATCOM when it is closely coupled to VSC2 (bus 10) as expected. With the STATCOM at bus 10 the oscillations in the VSC controlled real and reactive power become smaller. This is due to the better voltage profile at bus 10 during the fault when the STATCOM is placed. This test verifies that the STATCOM has the largest effect on the VSC HVDC connected bus voltage when it is placed at the location nearest to the VSC HVDC link.

Case Study 2 - Outer Control Loop Interactions
The STATCOM is kept at bus 10 in this case. The two typical VSC HVDC outer control schemes analysed before are tested in this case. Specifically, VSC2 outer control loops are configured to be in $PQ$ control and $P-V_{ac}$ control. Bus 10 is the PCC (point of common coupling) bus for the VSC HVDC link. The 100ms three-phase short circuit at bus 1 is again applied, and the integrated system responses are recorded and presented in Fig. 5.12. The case with no HVDC is also included in the results for comparison purposes. The STATCOM is to maintain a constant voltage level at the PCC bus during the fault. This voltage control is affected when the 500 MW VSC HVDC link is added. The voltage oscillation at bus 10 is improved by adding VSC HVDC, and it is further damped when $P-V_{ac}$ control is adopted in the VSC HVDC link, as shown in Fig. 5.12 (a). This is expected as both STATCOM and VSC2 are contributing in voltage control as shown in Fig. 5.12 (b) and (c). Here they act in a collaborative way, as the voltage set points for the STATCOM and VSC2 are the same, which agrees with the results shown in the investigation of the reduced network. Adverse interactions when PQ control is employed in VSC2 do not occur as the connected AC system is strong. However, with a short electrical distance between the STATCOM and the VSC in voltage control mode, control interaction may occur.
between the STATCOM and VSC2 as they are both trying to control the bus voltage. The voltage reference set points for both devices need to be controlled in coordination, otherwise adverse interactions might occur.

![Graphs showing system fault responses for different STATCOM locations.](image)

![Graphs showing system fault responses for different VSC2 controls.](image)

Fig. 5.11 System fault responses for different STATCOM locations.

Fig. 5.12 System fault responses for different VSC2 controls.
5.5. Conclusions

The potential interactions between a STATCOM and a point-to-point VSC HVDC link operating simultaneously in an AC system are analysed. Interactions are identified both in the plant models and the outer controller loops between the two components. A mathematical reduced network model is utilized in order to quantify the degree of the plant model interactions, and the outer loop interactions are clearly shown by means of modal analysis.

It has been demonstrated that the main factors that affect the degree of interaction are:

i. The electrical distance between two devices,

ii. The strength of the connected AC system,

iii. The type of controls employed in the devices.

The interaction becomes most noticeable when the two components are located in electric proximity with a very weak AC system. Under such system conditions, adverse interactions between VSC HVDC and a STATCOM may occur. This is specifically caused by a VSC in \( PQ \) control mode when the bandwidth of its \( P \) control loop is tuned to be very high. For different VSC control strategies the AC voltage control in a VSC also interacts with the STATCOM voltage control. However, with properly tuned controllers, the STATCOM and VSC can work coordinately during an AC system short circuit event.

Test on the dynamic GB system validates the results obtained from the reduced network. However, as the dynamic GB system is in fact a very strong system with high short circuit ratio, the degree of interaction between the STATCOM and VSC HVDC is small. With well-tuned controllers, a good collaboration in voltage control between the STATCOM and the VSC HVDC link is observed.
Chapter 6. Additional Control Requirements for VSC HVDC - A Specific Case Study

This chapter investigates the capability of VSC HVDC to restore local system power balance using the two-area AC system with an injection VSC HVDC link initially, considering the loss of a tie-line. The impact of generator controls is considered. Adaptive power control schemes are proposed for the grid connected converter when generation and demand imbalance occurs in the local system following a major system fault event. Successful implementation of the proposed controls enables the connected VSC HVDC links to improve power system stability. The proposed control is then tested on the dynamic GB system model.

6.1. Power Balance between Generation and Demand

For normal variations of system demand and operating conditions in conventional interconnected power systems, the balance between the mechanical power supplied to generator prime movers and generator output electrical power is maintained by the combined regulating reserve of all system units. However, when the condition of quasi-equilibrium is upset by a major disturbance, such as the loss of a major tie-line or a sudden change in the load demand, a severe generation/demand imbalance can occur. Over short time frames (a few or tens of seconds), imbalances between generation and demand are managed using frequency response services such as turbine governing systems. Ways like load shedding and scheduled generator tripping can be used for emergency situations. However, the problem with these schemes is that the power mismatch in the system might not be exactly compensated
over a short time period, and the system can still be in the danger of instability. Over longer time frames, balance between generation and demand needs to be rearranged based on post fault generation dispatches and load flow scenarios, otherwise this might result in unacceptable frequency excursions. In addition to conventional methods, VSC HVDC is considered a potential solution to improve the situation of power imbalance in local systems. However, before introducing any additional controllers for VSCs, let us briefly review the principle of generation/demand balance in the conventional power system.

**Principle of Power Balance in Conventional Power Systems**

The active power balance in the conventional power system is controlled by the generators. A general expression for the power in a generator can be written as:

\[ P_m = P_e + P_a \]  

(6.1)

where \( P_m \) is the mechanical power supplied to the generators by prime movers, \( P_e \) is the electrical power output of the generators, and \( P_a \) is the power accelerating or slowing down the generators. Assuming a sudden decrease of the active power consumption of the load (i.e. as a result \( P_e \) falls), the generator mechanical power \( P_m \) will remain constant if no control actions are taken. An accelerating power will arise, leading to an acceleration of the generator rotation speed and thus of the system frequency (\( f \)). The frequency change in each of the generators in the system is dependent on the variations in the kinetic energy (\( K \)) stored in the rotating parts of the generator which is given as:

\[ K = \frac{1}{2} J \omega^2 = 2J \pi^2 f^2 \]  

(6.2)

where \( J \) is the moment of inertia. Similarly, a sudden increase in the active power of the load will lead to a deceleration of the generator rotation speed and also of the system frequency.

On the other hand, the system voltage is mainly affected if reactive power imbalance occurs in the system. For instance, consider a case of a simplified generator model supplying a variable load as shown in Fig. 6.1 (a) with a lagging power factor \( cos \phi \).
The reactance of the generator is given by $X$ and its internal emf is $E$. A sudden loss of reactive power in the load will not affect the active power consumed in the load, the mechanical power supplied to the generator, and its internal emf if no control actions are taken. The power factor $\cos \phi$ is increased and the magnitude of current is decreased with the reduced reactive power in the load.

![Generator supplying variable load and voltage current phasors diagram.](image)

The voltage and current phasors before and after the loss of reactive power in the load are shown in Fig. 6.1 (b), labelled by subscript 1 and 2 respectively. It can be observed that before any control actions have taken place, there is a sudden increase in the magnitude of the generator terminal voltage as the voltage drop $ji_2X$ is reduced. The opposite will happen if there is a sudden increase in the reactive power in the load.

The above examples show how the frequency and voltage of a system can be affected when the active or reactive power balance is broken. The immediate system responses are illustrated before any control actions have taken place, which will help to understand how VSC HVDC can be used to restore the power balance in the system in the following studies.

**System Power Imbalance with VSC HVDC**

A specific case regarding a VSC HVDC supplied area being disturbed due to a major system event is analysed. This is considered as a potential scenario where additional controls are required from VSC HVDC to maintain system stability. In
this case study, the system dynamic behaviour following a fault event is presented, and typical signals are identified as indicating power imbalance in the system and can be used for enabling adaptive power controls in VSC HVDC links.

A schematic diagram is shown in Fig. 6.2 (a) as an example for such a situation. The local system is originally supplied by a generator and a VSC HVDC link. The power injected into this area is flowing into the local load demand and into the main grid through a main transmission line. A power mismatch can occur in this local system if the main transmission line is lost, due to a short circuit fault in the line or a sudden change of load demand in the main grid. The turbine governor system in the local generator can adjust its mechanical power input to match the new electric power output after the fault. However, this method can be slow depending on the type of the generation. The generator’s maximum mechanical power capability may be insufficient if the power imbalance in the system is too large.

Additional power control in the VSC HVDC link may be used to quickly mitigate the problem of power mismatch in this area. However, as VSC HVDC links are normally operated at their maximum available power \(^1\), they are more useful in situations where a power run back or power reversal is needed to reach a new power equilibrium point in the system.

As shown in Fig. 6.2 (a), the original system power balance is written as:

\[
P_m = P_e = P_{Ex} - P_{DC} + P_{Load}
\]  

(6.3)

Considering the case when the middle line is disconnected due to a short circuit in the line, then \(P_{Ex} = 0\). Fig. 6.2 (b) depicts the system power imbalance situation as:

\[
P_{e_{new}} = -P_{DC} + P_{Load}
\]

(6.4)

\[
P_m > P_{e_{new}}
\]

The amount of energy mismatch in the local system \(\Delta E\) is different depending on the speed of re-establishing the power balance in the system. The faster the power

\(^1\) For windfarm connected systems, the HVDC link would carry the maximum power available for the windfarm. For interconnectors, the situation depends on contracted supply arrangements. In addition, the overload power of converters is limited: power semiconductors have negligible thermal mass, so the maximum power is about 1 p.u. unless this overload power rating is ‘bought’.
compensation is provided, the smaller the energy mismatch and the system is more likely to be stable after the fault event.

![Diagram](image)

Fig. 6.2 (a) Diagram for specific case study and (b) Representation of power imbalance in the system.

**Example Case**

Such a situation is tested on the modified two-area test system with a VSC HVDC link, as shown in Fig. 6.3 (there is only one tie-line between bus 7 and 8). The purpose of this example is to investigate the dynamic responses of the power system immediately following a major system fault event. Consider the worst case scenario where the load in this local area is a static constant MVA load (motor driven) and there is neither turbine governor nor VSC HVDC power support. The VSC HVDC link is operated with VSC1 regulating the DC side voltage and VSC2 in constant power control. The external grid is assumed to be a strong AC system represented by an infinite bus that has enough capacity to take full power reversal in the DC link. Details of the AC system can be found in Chapter 2. The generators have AVR and PSS equipped.
A tie-line (line 7-8) disconnection event is applied at 2s. The initial power exported from Area 1 to Area 2 (400MW and 100MVAr) drops to zero due to the line break. The system responses are presented in Fig. 6.4.

According to the simulation results of the test system model in Fig. 6.4, the following phenomenon is observed:

i. The system voltage and frequency start to increase until instability occurs after 5s. The phase angle at the generator bus 2 with reference to the slack bus is also affected after the fault.

ii. At the instant of the fault event, both real and reactive power exported from this local area is largely reduced. The generator rotor starts to accelerate
because of the decreased air gap torque. This acceleration will continue if the imbalance between the generation and demand exists. The generator turbine power does not change as no governor is applied. The generator terminal voltages have a sudden increase due to the fact that the $lX$ drop in the generator winding decreases while the emf generated is the same. The voltage continues to rise as there is more reactive power injected into the local system than exported. However, the AVR equipped in the generators will act to bring this voltage back to the set point value by reducing the excitation.

iii. Meanwhile, the VSC HVDC link is also affected by the fault event. The PCC bus 7 voltage increases beyond the maximum VSC2 AC side voltage that can be synthesised from the DC link after the fault. The voltage difference between bus VSC_AC2 and bus PCC2 is shown in Fig. 6.5 left. It can be seen that the VSC_AC2 bus voltage actually becomes lower than the PCC2 bus voltage after 4.5s. Under such circumstances the power from the DC side does not follow the normal rules for linear output AC voltage modulation and transfer into the local AC system, causing the DC link power to be reduced and reversed (Fig. 6.5 right). DC system instability is observed after 5s.

Restoring Power Balance by Generators
To address these problems, the turbine governors in the generators can firstly be used to maintain system stability. Different types of turbine governing systems have different response rates which can have an impact on the system’s stability. For instance, hydraulic turbine governors are normally designed to have relatively large
transient droops and longer resetting times than steam turbine governors, and therefore they have slower responses [20]. Considering the test system in Fig. 6.3 with steam or hydraulic type turbine governing systems equipped in all generators, the input turbine power for the generators will drop at different rate when the generator speed is accelerated. For the tie-line disconnection event, a comparison of the effect of different governors on the system responses is presented in Fig. 6.6.

![System responses with steam and hydro type governors.](image)

It is seen that steam type turbine governing systems provide a quicker turbine power adjustment to restore power balance in the system, and thus the system is stabilized following the event. The system with slower hydraulic governors cannot quickly reach a new equilibrium point, which results in instability in the VSC HVDC link. The simulation results obtained from the test system suggest that instability could occur on both AC and DC sides of the system when power imbalance occurs under situations of: (1) no control actions taken or (2) the control actions taken are not fast enough. In the following sections, the capability of the VSC HVDC link to provide power support to the grid is examined. Different types of controls schemes in the grid connected VSC are proposed to meet the system stability requirements. The effects of control parameter settings, system configurations and ramp rate settings in the VSC are then addressed. To see the effect of the proposed controls in the VSC HVDC clearly, generator governor models are removed.
6.2. Restoring Power Balance by VSC HVDC Action

The VSC HVDC connection itself has strong impact on the system stability. This is especially true for high power import cases for a local area system. Severe frequency deviations can occur under power imbalance conditions due to the fact that the penetration of HVDC links, which are non-synchronous generators, replaces conventional synchronous power plants. However, VSC HVDC systems also provide the capability of fast and independent real and reactive power control, which can be used to quickly reach a new equilibrium point for generation and demand in the system. Based on the simulation results obtained before, the three signals in Fig. 6.4 (i.e. system voltage, frequency and phase angle) are strongly affected during the fault event, and they can be considered as triggering signals for the grid connected converter to control its power reference set point through a droop setting.

**Droop Type Control for AC System Power Support**

Droop control settings can be used in the grid connected converters to enable the VSC HVDC link to contribute in maintaining system power balance. Some forms of droop control structure has been seen proposed in [40, 106] for main grid frequency support. In this case, any of the three signals (voltage, frequency or local angle) can be used and their block diagram representation is shown in Fig. 6.7. With this configuration, the active power reference set point is modified by the input signal through a droop gain setting, as given by the following equation:

\[ \Delta P = \Delta (f, v, \phi) \cdot k_{\text{droop}} \]  \hspace{1cm} (6.5)

where \( f, v \) and \( \phi \) stands for the measured system frequency, voltage and phase angle provided by phasors measurement units (PMU) devices.

Fig. 6.7 Droop type control to enable VSC HVDC for system power support.
The controls with different input signals are implemented in the test system (Fig. 6.3). An auxiliary signal is sent to the grid connected converter VSC2 modifying its power reference set point when subjected to the tie-line disconnection event. Different droop gain values are applied to show their effect on the system stability performance after the fault.

*Droop Control with Measured Frequency and Voltage as Inputs*

The system responses are presented in Fig. 6.8 and Fig. 6.9 when the measured frequency and voltage are used as the input signals. The case without the droop type control is also presented in Fig. 6.8 which goes unstable after 5s. With the frequency droop control applied, the system frequency deviation is detected by VSC HVDC, which then starts to reduce its active power injection to reach a new equilibrium point. For a small droop gain settings ($f_{\text{droop}}=10$), the power reduction in the VSC HVDC is not fast enough and result in system instability after 6.5s. When the droop gain is increased ($f_{\text{droop}}=30$), the system is stabilized after the fault event. Therefore, in this case, the speed of power reduction in the DC link varies with the droop gain value — the larger the droop gain value, the faster the power reduction.

![Figure 6.8 System responses with frequency droop control.](image-url)
It is also the case when the measured voltage is used as the input signal. However, in this case, both voltage droop gains ($v_{\text{droop}} = 1$ and $10$) stabilize the system after the fault event (Fig. 6.9). Again, a higher droop gain results in faster power change in the VSC HVDC and less voltage and frequency deviations in the system.

**Droop Control with Measured Phase Angle as Input**

With rapid advancements in wide-area measurement system (WAMS) technology, remote signals in the power systems are made to be available in local controls by utilizing the synchronized PMUs. These PMUs are deployed at different locations of the grid to get simultaneous data of the system in real time, and the PMU signals are delivered at a rate up to 60 Hz [107, 108]. Therefore, with such a technique, it is possible to use the measured phase angle as an auxiliary signal for modifying VSC power reference settings. However, one potential problem claimed in [108] can be the delay involved in transmitting the measured signal. Typical time delays can be up to 1s, depending on the distance, transmission channel and other technical factors. This is close to the time constants for the controls employed in the VSC HVDC link,
and possibly deteriorates the controllers’ dynamic performance. To incorporate the delays in the model, a delay function is expressed as:

\[ G_{\text{delay}}(s) = e^{-sT_{\text{delay}}} \]  

\[(6.6)\]

Fig. 6.10 VSC control using PMU signal with time delay.

In this case, a PMU model is placed at the generator bus 2 and takes measures of its phase angle with respect to the slack bus angle. This is sent to as an input signal to the droop type control employed in VSC2. The simulation of the tie-line disconnection event shows that the phase angle type droop control is also able to modify the VSC output power and stabilize the system after the fault event without considering the time delay in signal transmission. Variations in the droop gain value have similar effects as the cases with frequency and voltage type droop controls. However, when time delay in the signal transmission is considered (with the model
shown in Fig. 6.10), the performance of the controller appeared to be poor and was even worse with increasing amount of delay. Fig. 6.11 presents the system responses after the tie-line disconnection considering different PMU signal transmission delays in the phase angle type droop control in VSC2. The system dynamic performance is deteriorated with an increased delay time, which then goes unstable with a time delay larger than 700ms.

Based on the simulation results for the droop type controls with different input signals, a discussion is provided:

i. It can be seen that with a larger droop gain setting, the speed of power response increases. Meanwhile, the magnitude of the oscillations in the DC voltage also increases significantly (as shown in Fig. 6.8 and Fig. 6.9). However, this is mainly due to the initial overshoots in the measured signals when the fault occurs. Therefore, a low pass filter (LPF) may be required for the measured signal to remove the initial overshoots as well as any higher frequency oscillations. The figure below shows the input frequency with and without a LPF when a droop type control is employed in VSC2 after the tie-line disconnection. This can also be applied when voltage or phase angle is used as the input signals.

![Fig. 6.12 Effect of low pass filter for the measured frequency signal.](image)

ii. For a relatively large droop gain value, the reference power set point of the VSC HVDC varies with the measured signals, even in normal operating conditions where very small fluctuations exist. This can result in undesirable power oscillations in the VSC HVDC system in normal conditions.
iii. The droop gain needs to be properly tuned for different system conditions depending on the plant model. For instance, the magnitude of frequency deviation can vary with system inertia and fault events, which will then affect the amount of power support provided by VSC HVDC. Although large droop gain values increase the response speed of the VSC HVDC, they can also deteriorate the DC system dynamic performance and lead to instability.

Proposed Control for Grid Power Support
In practice, voltage based droop controls are normally used as an auxiliary signal to modify reactive power references instead of active power references. Also, the phase angles in the system are always varying and it is difficult to keep track of the phase angle difference between a particular bus where PMUs are installed and the slack bus. Therefore, a modified control scheme proposed in this section is based on the type of droop control using frequency measurements as the input to address the problems raised before.

National Grid real time system frequency historic data suggest a normal frequency fluctuation between ±0.1Hz. Fig. 6.13 shows the typical frequency data for a normal month in 2014. With a large frequency droop gain value, very small fluctuations in the measured frequency signal may cause undesirable power variations in VSC HVDC. Therefore, the power reference set point should not be disturbed by small frequency variations.

Additionally, as mentioned before, the frequency deviation can vary with different systems. This can have an impact on the selection of the droop gain value $f_{droop}$. For power plants with the same technology, the inertia constant is generally proportional to the rating, according to the data provide in [74]. Synchronous generators in
conventional power systems can contribute to this inertia. Renewable energy generation such as windfarms, photovoltaic units and HVDC interconnectors that are decoupled by the grid connected converters deliver little or even no inertial response. Replacing conventional generation by renewable generation can result in lower system inertia. However, in general, for the same amount of power imbalance in the system, large systems usually have a higher inertia constant and consequent lower frequency deviation in comparison with small systems. An example is given in Fig. 6.14, which depicts the frequency change of the small two-area system and the GB dynamic system for a same amount of power imbalance in the system. It can be seen that the frequency rises much slower in the case of GB system. Therefore, higher droop gain values (higher level of sensitivity) may be desired in the VSC HVDC to provide full power support to the grid for large systems with smaller frequency deviation.

Based on the above analysis, the modified droop characteristics for a VSC HVDC link is provided in Fig. 6.15.
A small dead-band characteristic of ±0.1 Hz is included for the droop type control to avoid active power oscillations due to small frequency fluctuations. A LPF is added for the measured signals to remove overshoots and higher frequency oscillations, which will reduce the level of oscillations in the DC link. The LPF $G_{LPF}(s)$ can be represented as:

$$ G_{LPF}(s) = \frac{1}{1+Ts} $$  \hspace{1cm} (6.7)

The dead-band characteristic can be achieved by using a look up table to determine the reference power set points depending on the value of the input frequency signals. The block diagram representation of this control is given in Fig. 6.16. High pass filters may also be added to remove steady-state frequency offset in practical cases.

An initial selection of the frequency droop gain can be made based on an estimation of the frequency deviation in the system for a typical fault event. This can be analysed by investigating the rate of change of frequency (RoCoF) [109]. A proper droop gain value can enable VSC HVDC systems to provide their maximum power support to the grid for a given frequency deviation.

When a fault event in the AC system occurs, the initial RoCoF is determined by the amount of stored rotational kinetic energy in the system. The rate of change of power in the VSC HVDC is then jointly determined by the RoCoF and the droop gain value. Therefore, since RoCoF cannot be controlled by VSCs, the value of the droop gain needs to be properly tuned to ensure a fast enough response speed for the VSC HVDC in face of system power imbalance situations.

---

1 Eventually other controls come into play, but the initial frequency deviation is set by inertia and possibly fast power electronic units such as VSC HVDC.
For an individual machine, the equation of motion is defined as:

\[
J \frac{d\omega}{dt} = T_a - T_e = T_{a,m,e}
\]  \hspace{1cm} (6.8)

\[
H = \frac{1}{2} \frac{J\omega_0^2}{V_{Abase}}
\]  \hspace{1cm} (6.9)

where

- \( J \) = the moment of inertia,
- \( \omega \) and \( \omega_0 \) = angular velocity and rated angular velocity,
- \( T_{a,m,e} \) = accelerating, mechanical and electromagnetic torque,
- \( H \) = inertia constant,
- \( V_{Abase} \) = nominal apparent power of the generator.

Neglecting the losses in the unit, the equation of motion can be written as:

\[
J\omega \frac{d\omega}{dt} = P_m - P_e
\]  \hspace{1cm} (6.10)

For multi-machine systems, neglecting the losses in the system, the equation of motion can be summed as:

\[
\sum (J\omega \frac{d\omega}{dt}) = \sum (P_m - P_e)
\]  \hspace{1cm} (6.11)

Substitute equation (6.9) into equation (6.11) gives:

\[
\sum \left( \frac{2H \cdot V_{Abase}}{\omega_0^2} \cdot \omega \cdot \frac{d\omega}{dt} \right) = P_{tot\_generation} - P_{tot\_load} = \Delta P
\]  \hspace{1cm} (6.12)

The summation of the term \( H \cdot V_{Abase} \) is essentially the total kinetic energy stored in the system. Simplifying the above equation in per unit form and assuming \( \omega \approx 1 \) results:

\[
2H_{system} \frac{d\omega}{dt} = \Delta P
\]  \hspace{1cm} (6.13)

\[
\frac{d\omega}{dt} = \frac{\Delta P}{2H_{system}} = k_{RoCoF}
\]  \hspace{1cm} (6.14)

where \( H_{system} \) is the total system inertia constant.

The ROCOF is thus mainly determined by the amount of the power imbalance and the total system inertia. Based on equation (6.14), the RoCoF of the system can be
estimated when subjected to a fault event that results in power imbalance. If the time required for the VSC HVDC to react and provide its full power support to the system is given as $t$, the system’s frequency deviation in that period can be estimated as:

$$\Delta f = k_{RoCoF} \cdot t$$

The estimated frequency change can help to set the initial droop characteristic. The value of $\Delta f$ determines the upper and lower frequency limits for the VSC HVDC to operate at its positive/negative maximum power ratings.

In application to the case before with the test system given in Fig. 6.3, considering a typical power imbalance of around 400MW ($400\text{MW} \approx 0.28 \text{ p.u.}$ on the base of 1400MW total generation in Area 1) and the total system inertia constant of $H=13$ consisting of two synchronous generators, the ROCOF is estimated as:

$$k_{RoCoF} = \frac{\Delta P}{2H_{\text{system}}} = \frac{0.28}{2 \times 13} \approx 0.01 \text{ pu/s}$$

The bandwidth of the VSC HVDC power loop can be in a range between a few Hz to tens of Hz. Therefore, a reaction time for the VSC HVDC of 0.5s to reverse its full power is assumed. The estimated frequency deviation is then calculated as:

$$\Delta f = 0.01 \times 0.5 = 0.005 \text{ pu}$$

This gives an estimated frequency droop design as shown in Fig. 6.17. The VSC HVDC link is operated at its maximum power rating of 400MVA.

![Estimated frequency droop characteristic](image_url)
Therefore, a frequency variation range of $\pm (0.005 \times 50 = 0.25Hz)$ for the VSC HVDC link to provide its full power is initially set. The critical values of the frequency droop characteristic are listed in Table 6.1.

<table>
<thead>
<tr>
<th>Droop design</th>
<th>Critical Points</th>
<th>Frequency in Hz</th>
<th>VSC HVDC Power in p.u.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low frequency point</td>
<td>1</td>
<td>49.65</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>49.9</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>50</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>50.1</td>
<td>1</td>
</tr>
<tr>
<td>Dead-band range</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High frequency point</td>
<td>5</td>
<td>50.35</td>
<td>-1</td>
</tr>
</tbody>
</table>

In this case, for a system frequency higher than 50.35Hz or lower than 49.65Hz, the VSC HVDC link operates in constant power mode. Fig. 6.18 presents the system responses with the proposed control in VSC2 for the tie-line disconnection event. It can be seen that the system is stabilized after the fault. The magnitude oscillation in the DC side voltage is reduced in comparison with the responses shown in Fig. 6.8. The VSC HVDC link provides its full power reversal with the designed droop setting.

Fig. 6.18 System responses with modified frequency droop control.
6.3. Effects of Ramp Rate Limiter

Power reversal in VSC HVDC systems is achieved by reversing the direction of the current instead of that of the DC voltage. It is claimed in [43, 110] that the VSC HVDC transmission system does not have thermal/mechanical systems that are affected by rapidly changing active power demand, and thus it provides the capability of fast power run back and instant power reversal (i.e. the ramp rate is theoretically only limited by the bandwidth of the power control loops from the perspective of DC controls). Electrical inductance in the system does limit rate of current change, but this is normally fast compared with AC system time constants. Therefore, available power ramp rate in the VSC HVDC link is normally constrained by the AC system strength, not DC controls. Some examples regarding power ramp rate in VSC HVDC can be found in [12].

If a limitation is to be applied to the rate of power change in a VSC HVDC link due to concerns in the AC system, a rate limiter can be added to the dq current reference value, as shown in Fig. 6.19.

The rate limiter with an internal variable \( x \) is defined as:

\[
x = \begin{cases} 
-rate_{\text{limit}} & \frac{u-x}{T_s} < -rate_{\text{limit}} \\
\frac{u-x}{T_s} & -rate_{\text{limit}} < \frac{u-x}{T_s} < rate_{\text{limit}} \\
rate_{\text{limit}} & \frac{u-x}{T_s} > rate_{\text{limit}}
\end{cases}
\]

(6.16)

\[
y = x
\]

(6.17)
In this case, an emergency rate limiter of 1GW/s and a reduced rate limiter of 500MW/s are assumed to be applied in the VSC HVDC link. The power response of VSC2 with a frequency droop gain of 30 (Fig. 6.8) is affected by the rate limiter as presented in Fig. 6.20.

![Comparison of VSC2 power responses with the effect of rate limiter.](image)

It is seen that the output power from the DC link is not affected when the emergency rate limit of 1GW/s is used. When a slow rate limiter (500MW/s) is applied, the rate of change of power exceeds these limitations. As a result, the power can only change at the limited rate. Therefore, in the case that a rate limiter is required (from the AC system point of view) in the VSC HVDC link, its effect needs to be taken into consideration when designing a droop based adaptive power controller.

### 6.4. Restoring Power Balance Using VSC HVDC in Dynamic GB System

By linking to other countries’ transmission systems, National Grid has increased the diversity and security of energy supplies in UK. Apart from the IFA and the BritNed interconnectors, which are already in operation in the south of England, a number of new interconnector projects are proposed in the south of England. The 2014 National Grid Ten Year Statement lists a few of the links which are in the proposal shown in Table 6.2.
Table 6.2 Interconnector projects in South England.

<table>
<thead>
<tr>
<th>HVDC Interconnector</th>
<th>Location</th>
<th>Rating</th>
<th>Commissioning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nemo link</td>
<td>England - Belgium</td>
<td>1000MW</td>
<td>2018</td>
</tr>
<tr>
<td>IFA2</td>
<td>England - France</td>
<td>1000MW</td>
<td>2019</td>
</tr>
<tr>
<td>ElecLink</td>
<td>England - France</td>
<td>1050MW</td>
<td>2016</td>
</tr>
<tr>
<td>FABLink</td>
<td>France, Alderney and UK</td>
<td>1400MW</td>
<td>2020</td>
</tr>
</tbody>
</table>

The connection of multiple HVDC links in a local area can have significant impacts on the system stability as studied before. To investigate potential stability problems associated with future GB grid, a scenario is created based on the dynamic GB system with three VSC HVDC links rated at 1.2GW being connected to the South part of the system (bus 26-28). The other ends of the three DC links are connected to infinite AC buses representing other strong AC systems, which have enough capacity to take full power reversal in the VSC HVDC links.

It is assumed that all three links are operated at 1GW, which is not their full power rating, leaving a headroom of 200MW. A new load flow with the addition of the DC
Additional Control Requirements for VSC HVDC

Chapter 6. Additional Control Requirements for VSC HVDC

links is satisfied by the method of *distributed slack by load*, which is an option of balancing the power flow by means of a group of loads. Under such assumptions, the active power of the selected group of loads will be modified so that the power balance is once again met, while leaving the scheduled active power of each generator unchanged. An overview of the system scenario is provided in Fig. 6.21. It should be noted that there are two DC links importing power, while one is exporting as indicated in the figure.

Based on the frequency deviation estimation method, frequency droop type controls are employed in the three grid connected converters (VSC1-3) with properly tuned drop gain values. Considering a case where DC link 1 and 3 are importing power while DC link 2 is exporting power, the developed control schemes result in a characteristic shown in Fig. 6.22, where the dead-bands and frequency droop characteristics are included. Since the power headroom allowed in each VSC HVDC link is small (200MW), their “overloading” capability (e.g. import or export power larger than its rated value) is limited. Their main capability is to perform power run back or reversal when required. Applying the designed control strategies to the grid connected VSCs, DC link 1 and 3 is able to reduce the importing power when the generation is larger than the load demand in the system, while DC link 2 is able to reduce the exporting power when the generation is smaller than the load demand. Detailed parameters for the proposed control schemes are given in Table 6.3.

![Fig. 6.22 Designed control schemes for three grid connected converters.](image)
Table 6.3 Detailed parameters of the designed control schemes of the grid connected converters.

<table>
<thead>
<tr>
<th>VSC HVDC link 1,3</th>
<th>VSC HVDC link 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency in Hz</td>
<td>DC Power in p.u.(base 1GW)</td>
</tr>
<tr>
<td>49.5</td>
<td>1.2</td>
</tr>
<tr>
<td>49.9</td>
<td>1</td>
</tr>
<tr>
<td>50</td>
<td>1</td>
</tr>
<tr>
<td>50.1</td>
<td>1</td>
</tr>
<tr>
<td>50.2</td>
<td>0</td>
</tr>
<tr>
<td>50.3</td>
<td>-1</td>
</tr>
<tr>
<td>50.5</td>
<td>-1</td>
</tr>
</tbody>
</table>

In this case, the generation units in the system have turbine governing systems equipped. Due to the meshed connections between the buses in South England (buses 18-29), it is difficult to separate a local system from the main system by tripping a single line — each bus is connected to the rest of the system with more than 2 lines and the power can always flow between buses through other intact lines. As a result, the situation of power imbalance and angular instability in the local system after an event of line break is not likely to happen in the south part of this dynamic GB system model.

Therefore, under such circumstances, load demand variation events are simulated in the dynamic GB system for the area within the dashed line in Fig. 6.21 to create imbalance between the system generation and demand. The total amount of demand change is evenly spread across all the loads in the area. This includes a sudden loss of 40% (circa 6.36GW) and a sudden increase of 30% (circa 4.77GW) of the total load demand in this area. Due to the size of the system, only the simulation results of selected system buses and generators, which are representative to reflect the responses of the whole system, are presented. It should be noted that these events are extreme cases and are only considered to show what functionality well-controlled VSC HVDC is capable of.

Fig. 6.23 shows the system responses without the power support provided by the VSC HVDC links. A sudden decrease of 40% of the load demand quickly raises the system frequency and voltage, and system instability occurs after 15s even with the
help of the turbine governors in the generators. The DC links are in constant power control which does not contribute to mitigating the power imbalance in the system.

Further tests enable the designed frequency droop controls in the VSC HVDC links, and the system responses to a sudden 40% load decrease and 30% load increase are depicted in Fig. 6.24 and Fig. 6.25 respectively. In case of a 40% load decrease, DC link 1 and 3 perform fast power reversal. A small increase in the power exported by DC link 2, from its rated value to its maximum value, also helps to mitigate the power imbalance in the system. Similar behaviours are observed in the event of a 30%
load increase where DC link 2 performs fast power reversal while DC links 1 and 3 provide maximum power import. With the help of the power support provided by VSC HVDC links, the system is stabilized after the fault events in both cases.

Fig. 6.24 System responses for a sudden decrease of 40% load demand in a particular area (VSC HVDC links with designed frequency droop control).
Fig. 6.25 System responses for a sudden increase of 30% load demand in a particular area (VSC HVDC links with designed frequency droop control).

6.5. Conclusions

The chapter starts with the result of a dynamic simulation of an example test system subjected to a major disturbance to illustrate the power imbalance problem in such situations. The theory of the system behaviour when power imbalance occurs is presented. It is identified that large power imbalance in the system may result in
system instability if the turbine governing systems equipped in the generators do not respond fast enough. Under such circumstances, control methods are proposed for grid connected VSC HVDC links to improve power system stability by quickly changing their power output to help the system reach a new equilibrium point. Based on the analysis of different input signals, a frequency based droop control is proposed. To design the droop characteristic, the system frequency deviation under power imbalance situations is estimated. It is demonstrated that both the value of the droop gain and the ramp rate limit can affect the rate of power change in the VSC, and both need to be taken into considerations in the design stage. The droop gain value in the proposed frequency based droop control may need to be adjusted depending on factors such as system conditions, the amount of power imbalance and the total inertia in the system. Successful implementation of the proposed frequency based control schemes demonstrates the effectiveness of using VSC HVDC to provide additional power support in a future scenario based on the dynamic GB system.
Chapter 7. Conclusions and Future Work

This chapter presents the conclusions of this thesis and recommendations for future work.

7.1. Conclusions

The thesis identifies and investigates the potential problems and effects of having VSC HVDC technology in the AC power system. In completing this research, an assessment of the AC/DC control interactions is provided with the focus being put on the electromechanical transient performance.

A brief review of the development of HVDC and past research on the integration of VSC HVDC into conventional AC system is provided in this thesis, from which potential problems and gaps within the related areas are raised. The issues regarding the incorporation of VSC HVDC into AC system mainly fit into three aspects, namely: (1) AC/DC modelling, (2) VSC HVDC-AC system control interactions and (3) VSC HVDC-FACTS control interactions. To tackle the identified problems and fill the gaps to date for the research in this area, several targeted studies have been carried out within the thesis. These are summarized as:

i. Development of generic integrated AC/DC system models.
ii. Development of dynamic GB system with greater fidelity.
iii. Comparison of control strategies employed in VSC HVDC links and MTDC systems and their effects on AC system stability.
iv. Identification and analysis of control interactions between VSC HVDC and STATCOM.
v. Analysis of additional control capability of VSC HVDC links for main grid active power support.

The outcomes of these five studies are the original contributions of this thesis. The issues raised from the potential aspects have been fully addressed with further work that has been undertaken in some of the areas. Details regarding the contributions made by each of the studies to the problems of concern are addressed in the following sections.

**AC/DC Modelling**

To study AC/DC control interactions, generalized integrated AC/DC models have been developed. The modelling of the key components and the associated controls in the AC and DC sides of the system has been described in detail. However, integrated AC/DC system models for power system stability studies are often based on simplified AC or DC side models. Even though detailed integrated models are seen in some of the publications, the integration method has also not been addressed in detail at the time of study. Therefore, a mathematical integration method is proposed that is the first original contribution in this thesis. Instead of having one side of the system to be modelled in a simplified way, the full VSC HVDC and AC system models for power system stability studies are used. This includes the plant models and controls of the converters and AC system generators. The method allows the VSC models to be developed separately by considering them as current injections into the connected AC system, and it therefore provides an alternative for quickly integrating new VSC models into conventional power system models.

Following the development of generic AC/DC system models, another original contribution made in this thesis is the development of a dynamic GB system model. The developed model is based on a steady-state, representative load flow data of the GB transmission network with the intention of testing probable future scenarios with greater fidelity. The design of the generator controls (i.e. AVR, PSS and GOV) is shown in a step-by-step procedure, and the method to modify the developed system into other loading conditions is also provided. The form of the resulting dynamic system has been designed to represent the main bottlenecks for inter-area power
transfers, retaining the parameters (impedances and ratings) of the real circuits through those bottlenecks, but reducing the electrically close substations to representative clusters. The significance of constructing this dynamic model lies upon allowing exploration of a more realistic system as well as its related stability and control issues. The detailed construction procedures as well as the full system data have been included in this thesis, which provides a method of converting a steady-state model into a dynamic model and also allows reproducing the system. The AC/DC interaction studies that based on this more realistic large power system model help to ensure that the exploration of the fundamental phenomena is representative of practical system implementations to a greater extent.

**VSC HVDC – AC System Control Interaction**

The approaches of past research to the control issues of integrated AC/DC system tended to view the problem with an emphasis on either the AC system or the DC system, with consequent simplifications of the other side. This has the risk of ignoring some potential control interactions in between. In this thesis, a holistic approach was taken that utilized a detailed AC/DC modelling methodology and control designs. As there is no available study that compares the effect of VSC outer controls on the AC/DC system dynamic performance, a systematic assessment of VSC controls is provided. The outcome of such a study provides recommendations for the selection and tuning of the controls for VSC HVDC, which can improve the AC system stability. The influence of a 4-terminal DC system control settings on the DC system power flow and the resulting AC system dynamics is also described. In this respect, the next original contribution of the thesis presents both a novel methodology for controller analysis and a new set of controller configuration recommendations.

To be more specific, the AC system inter-area oscillation is mainly affected by the operating point of the DC link (power flow) and the VSC AC voltage control. Installation of a paralleled VSC HVDC link usually affects the damping of the connected AC system inter-area mode, which not only depends on the AC system structure but also on the type of controls employed in the converter terminals.
Another major conclusion is that a fast acting AC voltage regulation at the receiving end of the VSC HVDC link reduces the damping of the low frequency inter-area mode, whereas it would improve damping at the sending end. Analysis of the MTDC control strategies shows that the adopted MTDC control scheme can significantly affect the DC power flow and thus lead to different corresponding AC system responses. Constant DC voltage control with voltage margins provides satisfactory integration of small scale AC-MTDC systems. The responsibility of DC voltage control can only be transferred but not shared. It is recommended that for large DC grid integration, droop controls between DC system voltage and power should be used. It is demonstrated that droop control characteristic in the DC grid allows balanced AC/DC dynamic performance and flexible DC grid power control capability, which can be used to achieve an optimal power injection scenario for the connected AC system.

In order to fully utilize the potential of the VSC HVDC, a frequency based droop control method is proposed in this thesis to enable the active power support function of VSC HVDC links together with the control design method. Successful implementation of the proposed control schemes demonstrates the effectiveness of using VSC HVDC to provide additional power support. However, affecting factors that need to be considered in the controller designing stage (i.e. droop gain setting and ramp rate limit) are addressed.

**VSC HVDC - FACTS Control Interaction**

The last original contribution made in the thesis addresses the potential control interactions identified between VSC HVDC and STATCOM. Interactions are identified in both the plant models and their outer controller loops, considering factors such as the electrical distance between the two components, the strength of the connected AC system and the type of controls employed. Due to the cascaded control structure of VSC and STATCOM, a method combining relative gain array and modal analysis techniques is used to address interactions occurred at multiple levels. Adverse control interactions are identified when the two components are located in electric proximity with a very weak AC system. In such conditions, the
STATCOM AC voltage control can be deteriorated by a closely located VSC real power control with very high bandwidth. The validation of the interaction study in the dynamic GB system shows a good collaboration between a VSC HVDC link and a STATCOM operating in electric proximity. This is due to the fact that the GB system is a strong system with high short circuit power ratios, and thus the controls in the STATCOM and the VSC are well-decoupled.

7.2. Future Work

The objectives of this research have been met by the work presented in this thesis. However, the studies also suggest a number of areas where further work can be carried out. The following are recommendations of possible future work worth pursuing.

Effects of MTDC Systems on AC Networks

As the trend of HVDC development is expanding towards MTDC grid, the power flow in the DC grid will become more complex and so will the controls in the converter terminals. It is shown in this study that (1) the power flow in the VSC HVDC link and (2) the AC voltage control employed in the converter terminals have the most significant effect on the AC system inter-area oscillation. Therefore it is necessary to do further work in order to address:

i. The effect of MTDC system optimal power flow scheme not only on the DC system dynamic performance, but also on the AC system electromechanical oscillations if such a problem is of concern.

ii. The coordinated tuning of AC voltage control when it is employed in multiple grid connected converters as both the parameter settings and the location of the control can substantially affect the AC system inter-area oscillatory behaviour.

Furthermore, similar to the automatic generation control in the conventional AC systems, optimal power flow in a MTDC system may require properly designed power flow reference orders for all interconnected converter stations. Advanced
controls based on telecommunication technologies may be required to cooperate with local station control and to overcome conventional operational speed limitations. Since telecommunications and controller architectures are intimately linked, the impact of related constraints need be incorporated to develop a “supervisory master control” that improves MTDC system performance and offers robust and reliable services to AC onshore networks. A higher level control system modelling is required.

**Extended Interaction Studies**

System level electromechanical control interactions between VSC HVDC and STATCOM are analysed in this study. The analysis is carried out from the stability point of view, and therefore very detailed and fast electro-magnetic transients are out of the scope. To fully capture the adverse interactions of interest, more accurate representations of the key components may be required. Further analysis requires greater model fidelity with the focus being put on fast dynamics such as electromagnetic transient interactions and signal harmonic distortions (e.g. There could be some harmonic effects that might lead to some adverse interactions between electrically close devices).

With the increasing installations of HVDC projects and the development of MTDC systems, fast DC grid system wide control interactions between converters and nonlinear interactions (e.g. converter protections, limits, switching controls etc.) may arise. Potential interaction studies should also consider cases between different converter stations or between converters and other FACTS devices (e.g. TCSC, SVC, SSSC etc.). VSC HVDC systems for offshore windfarm connections need to consider electromagnetic transient interaction between wind turbines and windfarm side converter stations. To handle the increased penetration of power electronic devices in the future power system, coordinated control strategies to avoid adverse control interactions between the devices are necessary.
References


Appendix

Appendix A

Power System Stability Basics and Techniques

A1. Electromechanical Oscillations

Rotor angle stability depends on the ability to maintain equilibrium between the electromagnetic torque and the mechanical torque in each synchronous machine, after being subjected to small-signal or large disturbances. The power-angle characteristics suggest the power output of a synchronous machine varies as rotor angle oscillates [20].

Under steady-state conditions, the rotor speed remains constant due to the balance between the mechanical and electrical torques. However, when the system is perturbed by events such as load variations, short circuits, loss of generation, etc., the system equilibrium point will be varied, which leads to the acceleration or deceleration of rotors according to their rotating motion characteristics. Furthermore, as the angle difference between two generators varies due the unequal rotor speed, oscillations of the power exchange between the two machines occur. The equation of motion of a synchronous machine is given as:

\[ \frac{2H}{\omega_0} \frac{d^2 \delta}{dt^2} = T_m - T_e - K_D \Delta \delta \]  \hspace{1cm} (A1)

In the above equation, \( H \) represents the inertia constant. The angular position of the rotor in rad is denoted by \( \delta \). \( T_m \) and \( T_e \) represent per-unit mechanical torque and electrical torque respectively. \( K_D \) is the damping coefficient in per-unit torque/speed deviation.

The effect of the mechanical losses on rotor oscillation damping is usually small, and they can be neglected under most practical conditions. For synchronous
generators without POD controls, the primary source of damping is provided by damper/amortisseur windings, which have a high resistance/ reactance ratio. In transient state, a current will be induced in the damper windings by the air-gap flux whenever the rotor speed differs from the synchronous speed. The induced current will generate a damping torque, which will counteract the rotor speed deviation. The change in electrical torque of a synchronous generator following a disturbance comprises two components:

\[ \Delta T_e = K_s \Delta \delta + K_D \Delta \omega \]  \hspace{1cm} (A2)

The synchronising torque component \( K_s \Delta \delta \) is in phase with the angle deviation, while the damping torque component \( K_D \Delta \omega \) is in phase with the speed deviation. Lack of synchronising torque induces aperiodic drift of the rotor angle, whereas insufficient damping torque results in oscillatory instability, as shown in Fig. A1. Practically, most small-disturbance instability is caused by the lack of damping, as sufficient synchronising torque can be provided by excitation control.

Based on equations (A1) and (A2), the classical single-machine infinite bus model without considering field circuit dynamics, amortisseur dynamics and excitation control, can be represented using the block diagram shown in the following figure.
The effects of the field flux linkage variation and the automatic voltage regulator (AVR) on synchronising and damping torque components are analysed in [20]. At oscillating frequencies higher than a certain value, the field flux variations due to $\Delta \delta$ induce a positive damping component. However, the AVR action can result in a negative damping component and weaken the system damping, especially for high generator outputs and high reactance values of the external system.

Generally, both synchronising and damping torques under the condition with and without damping control can be calculated and compared in order to evaluate the impact of the POD control on the system damping. This approach is particularly suitable for the damping controls of local area oscillations. Adding a well-designed PSS usually enables a large increase of the damping torque component. It should be noted that the result of damping torque analysis should agree with that of the eigenvalue analysis.

Power oscillation problems can be categorised into local oscillations and global/inter-area oscillations [84]. Local mode oscillations are associated with the rotor angle oscillation that swings against the rest of the power system. Local problems can also refer to the oscillations between a few generators close to each other. The frequency range of local modes is normally between 0.8 to 2.0 Hz.

Inter-area oscillations usually involve groups of generators oscillating against other groups of generators, which can be far away from each other. Inter-area modes usually have a frequency range of 0.1 to 0.7 Hz, lower than that of the local modes.
Normally, inter-area oscillations occur between two subgroups of generators which are interconnected by weak tie-lines. However, for some very low frequency inter-area modes, all the generator plants in the system may be involved. Unlike local area modes, which require detailed modelling and analysis only in the vicinity of the plant, the entire interconnected system may need to be represented in detail to investigate inter-area modes. A fundamental understanding of inter-area oscillations is well-documented in [93].

A2. Modal Analysis Basics

Modal analysis based on state-space representations is the most widely used technique to investigate small-signal stability and to identify oscillating modes in power systems. Dynamic behaviour of a power system can be represented using a set of first-order differential equations shown in equation (A3) and (A4), where the vector $x$ refers to the state variables, and $u$ is the vector representing the inputs to the system.

\[
\dot{x} = f(x, u) \quad (A3)
\]
\[
y = g(x, u) \quad (A4)
\]

By linearizing the system based on an equilibrium operating point, the state-space representation of a dynamic system can be obtained as:

\[
\Delta \dot{x} = A \Delta x + B \Delta u \quad (A5)
\]
\[
\Delta \dot{x} = A \Delta x + B \Delta u \quad (A6)
\]

The eigenvalues of the system, denoted as $\lambda_i$, are the solutions of the following equation:

\[
det(\lambda I - A) = 0 \quad (A7)
\]

By using the transformation shown in equation (A8), where coefficients $z$ are defined as the modes of oscillation. $\Phi$ is the modal matrix of $A$.

\[
\Delta x = \Phi z \quad (A8)
\]
Consequently equations (A5) and (A6) can be transformed to a set of uncoupled state equations:

\[
\dot{z} = Az + \Phi^{-1} B\Delta u \\
\Delta y = C\Phi z + D\Delta u
\]  
(A9)  
(A10)

The time response of the \(i\)th state variable is given by:

\[
\Delta x_i(t) = \phi_i \psi_{i-1} \Delta x(0)e^{\lambda t} + \phi_i \psi_{i-2} \Delta x(0)e^{\lambda t} + \cdots + \phi_i \psi_{i-n} \Delta x(0)e^{\lambda t}
\]  
(A11)

where \(\phi_i\) and \(\psi_i\) represent the right and left eigenvectors respectively. It can be seen that the free response of the system at that operating condition is represented by a linear combination of \(n\) dynamic modes, where each mode has a corresponding eigenvalue. The scalar \(\psi_i \Delta x(0)\) gives the magnitude of the excitation of the \(i\)th mode.

The mode shape, which represents the relative activity of the state variable in a particular mode, is given by the right eigenvector (in equation (A8)). The mode shape technique is widely used to determine the input signals to the damping controllers.

The stability of the system is assessed by evaluating the eigenvalues. A real eigenvalue represents a non-oscillatory mode, while a pair of complex eigenvalues, as shown below, corresponds to an oscillatory mode. The damping of the mode is mainly determined by the real part the eigenvalue, and the oscillating frequency is given by the imaginary part.

\[
\lambda = \sigma \pm j\omega
\]  
(A12)

The damping ratio and the frequency of oscillation of the mode are expressed as:

\[
\zeta = \frac{-\sigma}{\sqrt{\sigma^2 + \omega^2}}, \quad f = \frac{\omega}{2\pi}
\]  
(A13)

The decaying rate of the amplitude of the oscillation is determined by the damping ratio \(\zeta\). To demonstrate the graphical pattern of eigenvalues, an illustrative eigenvalue plot is shown in Fig. A3, where the damping ratio for each mode equals the corresponding value \(\sin \theta\). Generally a POD control is designed to increase the damping of both the unstable modes and the critical modes of interest. Meanwhile, the POD control should not adversely affect the damping of other critical modes.
Participation factors, which are based on a combination of right and left eigenvectors, are appropriate indications of the relative participation of the respective states in the associated modes. They are commonly used to distinguish inter-area modes and local modes, and they help to select feedback signals for POD controllers. Generally, the state variables that have high participation factors in the critical modes are of particular interest. An inter-area mode usually involves participation of a large number of state variables from multiple generation groups.

The matrix $C\Phi$ is called observability matrix, which determines the relative contribution of the respective modes to the observed system outputs. If the feedback signal of a system is not appropriately selected, some poorly damped modes may not be observable, and thus the POD controller cannot provide satisfactory damping to these modes, especially for the inter-area modes. Therefore, the monitored quantities from the system should have high observability, particularly with respect to the poorly damped low-frequency modes.

Another commonly used technique in POD control design is the residue analysis, which relies not only on the eigenvectors but also on the input and output matrices. For an open-loop transfer function extracted from a multi-input multi-output system, as shown in equation (A14). The residue at the pole $\lambda_i$ is defined as $R_i$, and it represents the relative weight of the mode in the respective output.
The feedback signals are required to enable a large residue relative to the target mode, in order to obtain sufficient controllability over the mode of oscillation that is to be damped.

A3. QR Method

To understand the QR method [90] for eigenvalue calculations, there are a few basics that need to be specified:

i. In the QR method, $R$ is an upper triangular matrix and $Q$ is an orthogonal matrix which satisfies:

$$Q^T = Q^{-1} \quad \text{and} \quad R = \begin{bmatrix}
  a_{11} & a_{12} & \cdots & a_{1n} \\
  0 & a_{22} & \cdots & a_{2n} \\
  \vdots & \vdots & \ddots & \vdots \\
  0 & 0 & \cdots & a_{nn}
\end{bmatrix}$$

(A15)

If a matrix is a diagonal or triangular matrix, the eigenvalues of this matrix are the diagonal elements. If the state matrix $A$ can be transformed into such a form, then the eigenvalues can be picked up.

ii. Similarity transforms which have the form of $A' = BAB^{-1}$ will not affect the eigenvalues. In other words, $A$ and $A'$ have the same eigenvalues. In the case that $B$ is orthogonal, the similarity transform can also be expressed as $A' = B^T A B$

iii. Eigenvalues can be calculated through QR iteration which requires QR decomposition at each iteration. These two key processes are explained here.

**QR Iteration**

Eigenvalues can be found using iteratively the QR-algorithm, which will use the previous QR decomposition. Given a state matrix $A$, its QR decomposition is a matrix decomposition of the form:

$$A = QR$$

(A16)
Using this as the initial value, a new matrix for iteration can be defined as:

\[ A_2 = RQ \]  
(A17)

This new matrix can be QR factorized as:

\[ A_2 = Q_2 R_2 \]  
(A18)

This process can be repeated by creating new matrices, e.g. \( A_3 = R_2 Q_2 \), which can be factorized into \( A_3 = Q_3 R_3 \). At the \( k^{th} \) step, a matrix \( A_k \) can be defined by equation \( A_k = R_{k,1} Q_{k,1} \) from the previous factorization of \( A_{k-1} \). Matrix \( A_k \) will tend toward a triangular or nearly triangular form whose eigenvalues are the diagonal elements. This is because that the matrix \( Q \) of QR decomposition is orthogonal, so that the iteration process is in fact:

\[ A = QR \quad and \quad R = Q^T A \]

\[ A_2 = RQ = Q^T AQ \]

This is a similarity transform. The resulting new matrix \( A_k \) will have the same eigenvalues as the original state matrix \( A \). With a large number of steps \( k \), the diagonal elements of \( A_k \) will converge to the original eigenvalues of state matrix \( A \).

**QR Decomposition**

There are different methods to compute the QR decomposition of the state matrix \( A \), such as the Householder transform, the Givens rotations and the Gram-Schmidt orthogonalisation. The first method “Householder transform” is briefly discussed here. The construction of \( Q \) and \( R \) is based on a series of orthogonal householder matrices \( P_1, P_2, \ldots, P_{n-1} \) that satisfy \( P_{n-1} \cdots P_2 P_1 A = R \), where \( R \) is an upper triangular matrix. This idea can be expressed as a process that continues until an upper triangular matrix \( R \) is obtained:

\[
P_1 A = P_1 \begin{pmatrix}
A_{11} & A_{12} & \cdots & A_{1n} \\
A_{21} & A_{22} & \cdots & A_{2n} \\
\vdots & \vdots & \ddots & \vdots \\
A_{n1} & A_{n2} & \cdots & A_{nn}
\end{pmatrix} = \begin{pmatrix}
\tilde{A}_{11} & \tilde{A}_{12} & \cdots & \tilde{A}_{1n} \\
0 & \tilde{A}_{22} & \cdots & \tilde{A}_{2n} \\
\vdots & \vdots & \ddots & \vdots \\
0 & \tilde{A}_{n2} & \cdots & \tilde{A}_{nn}
\end{pmatrix}
\]
During this tridiagonalization process, each householder matrix \( P_k \) can be calculated using the householder transformation. The householder transform is to find a set of transforms that will make all elements in one column below the diagonal vanish, and then \( Q \) and \( R \) can be calculated to create the new state matrix \( A \) for the next iteration.

### A4. Lead-lag Compensator

The lead-lag compensator is designed to add phase lead/lag to the system output. It has a typical form of:

\[
leadlag = k \frac{s + \omega_z}{s + \omega_p} \quad (k = \frac{\omega_p}{\omega_z}) \tag{A19}
\]

The lead-lag compensator contains a single pole and a single zero where \( \omega_p \) and \( \omega_z \) are the corresponding frequencies. It provides phase lead if the zero is closer to the origin than the pole (i.e. \( \omega_z < \omega_p \)), or phase lag if the pole is closer to the origin than the zero (i.e. \( \omega_z > \omega_p \)). When designing the compensation, the lead-lag compensator can be expressed in a slightly different format as:

\[
leadlag = k \frac{1 + Ts}{1 + aTs} \tag{A20}
\]

The lead-lag compensator is able to provide phase lead/lag at a particular frequency. With the above expression, some characteristics of the phase lead-lag block design are summarized:
i. Upper and lower cut-off frequencies: 
\[ f_{upper} = \frac{1}{T} \quad \text{and} \quad f_{lower} = \frac{1}{\alpha T} \]

ii. Frequency at where the maximum compensated phase occur: 
\[ \omega_m = \frac{l}{T\sqrt{\alpha}} \]

iii. Maximum compensated phase angle: 
\[ \phi_{max} = \arcsin\left(\frac{\frac{l}{\alpha} - 1}{\frac{l}{\alpha} + 1}\right) \]

An example bode plot of a typical lead \((\alpha = 0.5 \text{ and } T=0.2)\) compensator is shown below:

Fig. A4 Bode plot of an example lead compensator.
Appendix B
VSC Topologies, Losses and Capability

B1. Converter Topology

HVDC Light was first introduced by ABB in 1997. At the time it was a state-of-the-art power system designed to transmit power underground, under water, and also over long distances. It was claimed that this technology increases the reliability of power grids by extending the economic power range of HVDC transmission from a few tens of megawatts to 1200 megawatts at ±500kV. Examples include the first commercial project “Gotland HVDC Light”.

The converter topology shown below is a two-level converter which is used in the first and the third generations of HVDC Light.

![Converter Topology Diagram](image)

Each valve consists of a stack of series and parallel connected IGBTs with anti-parallel diodes. The number of series connected devices varies for different voltage and current rating requirements. Typically, extra grading components are added to the series connected IGBTs to ensure voltage sharing.

Considering one phase at a time, the converter output voltage can be $\pm V_{dc}/2$, when an upper valve conducts or a lower valve conducts respectively. By applying a pulse-width modulation (PWM) control scheme to the converter, the output waveform of each phase becomes some form similar to Fig. B2.
A sinusoidal voltage output is achieved after filtering. The quality of the resulting sine wave (the harmonic content) depends on the PWM switching frequency. There is always a trade-off between high switching frequencies and converter switching losses. A switching frequency of 1950Hz was used in the first generation of HVDC Light. Such a frequency can remove low-order harmonics, and thus filters are only required for higher order harmonics. This greatly reduces the footprint of a VSC station in comparison with a traditional current source converter station.

The instantaneous control of phase angle and voltage amplitude is achieved by changing the PWM pattern, while power flow reversal in VSC is achieved by changing the direction of current rather than the DC voltage polarity. VSC HVDC is also a self-commutated converter, and therefore it does not require an AC voltage source for commutation. This enables VSC HVDC the capability to connect a weak AC system such as an offshore windfarm.

The second generation HVDC Light used a modified three-level topology. After that, ABB reverted back to the two-level converter topology in its third generation of HVDC Light, but with a more advanced control scheme called “optimum PWM (OPWM)”. OPWM is designed to control the fundamental converter voltage, and at the same time optimizing the criteria for controlling the harmonics. It can selectively eliminate low-order harmonics for a given power level and switching frequency, and thus the switching frequency can be reduced. The 350MW ±150kV VSC HVDC scheme between Estonia and Finland used this Optimum PWM control with a switching frequency of 1050Hz.
The second generation voltage source converter topology produced by ABB is a three-level diode neutral point clamped (NPC) VSC as presented below.

This converter topology gives three different levels of output: $\pm V_{dc}/2$ and zero. The output waveform of a single phase is shown in Fig. B4.

The three-level output allows the switching frequency to be reduced for less converter losses without having worse output harmonics. However, this conventional diode-NPC converter suffers from the unequal distribution of semiconductor losses and valve voltage imbalance. The most stressed valve will limit the
permissible phase current and switching frequency for the converter. These issues lead to a modified active neutral point clamped (ANPC) VSC as shown in Fig. B5.

![Fig. B5 Single-phase active neutral clamped voltage source converter.](image)

The ANPC VSC is a NPC VSC with the addition of an active switch connected in anti-parallel with the NPC diodes. The addition of the active switches gives more switching states which allow the losses to be distributed more evenly. This allows an increase in the power rating and switching frequency compared to NPC. An example of this technique is the Murraylink and the Cross Sound Cable projects in 2002.

![Fig. B6 CTL converter single line diagram (modified from [111]).](image)
The fourth generation of ABB’s HVDC Light is a cascaded two-level (CTL) converter consisting of several smaller two-level building blocks, also called cells, which enables the creation of a nearly sinusoidal output voltage from the converter. The output AC voltage is adjusted by controlling the cells’ output voltage in each arm. For example, the output of cell 1 in Fig. B6 can be switched to be equal to the capacitor voltage by turning T2 on and T1 off, or zero by turning T2 off and T1 on. If both valves are turned off, the cell is blocked and the current is conducted only through the diodes. Each cell is switched at a low switching frequency, typically about 150Hz. But the effective switching frequency per phase is about 2N times the cell switching frequency, where N is the number of cells per arm. e.g. for N=38 cells per arm, the effective switching frequency per phase leg can be calculated as: 150×38×2=11.4kHz. This is in the range of 10 times the switching frequency of a two-level VSC, indicating an excellent dynamic response.

Siemens and Alstom Grid have also developed their multi-level VSC HVDC converter under the name of “HVDC Plus” based on modular multi-level converter (MMC), and “MaxSine” respectively. These two converter technologies both employ a similar topology. The MMC consists of six converter arms and each converter arm comprises of a number of modules (Fig. B7). Each module output voltage is equal to the capacitor voltage if the upper IGBT is on and the lower IGBT is off, or zero if the upper IGBT is off and the lower IGBT is on. This enables the converter phase voltage to be controllable with a smallest voltage step equal to the module voltage, thus is a few kV. Similar to the CTL, each sub-module individually switches in and out only once per cycle. Therefore, the switching frequency of each sub-module is reduced to the fundamental frequency (though further switching may be used).

MaxSine is a hybrid VSC technology which combines the advantage of low-pulse-number converters with PWM, and the multi-level approach. The semi-conductor switches are arranged to form the converter. The multi-level cells are used to synthesise a desired voltage waveform to satisfy the requirements of either the AC or the DC network.
The desired AC output voltage is achieved by controlling the ratio of the two arm voltages within the phase leg. Fig. B8 shows that a nearly sinusoidal sine wave can be produced with a much lower voltage step in comparison with the two-level or three-level PWM converter mentioned before.

Fig. B7 Three-phase MMC topology.

With high number of modules per converter arm, the output harmonic content is very low, and this means AC filtering is not necessary. The footprint of a VSC converter station can be greatly reduced. For multi-level systems, appropriate
division of the DC voltage between the capacitors on each level needs to be maintained.

**B2. Converter Losses**

The table below illustrates the improvements in the losses of different types of VSC HVDC converter.

<table>
<thead>
<tr>
<th>Converter technology</th>
<th>Converter Type</th>
<th>Typical losses per converter</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDC Light first generation</td>
<td>Two-level PWM</td>
<td>3%</td>
</tr>
<tr>
<td>HVDC Light second generation</td>
<td>Three-level ANPC</td>
<td>1.8%</td>
</tr>
<tr>
<td>HVDC Light third generation</td>
<td>Two-level OPWM</td>
<td>1.4%</td>
</tr>
<tr>
<td>HVDC Light fourth generation</td>
<td>CTL</td>
<td>1%</td>
</tr>
<tr>
<td>HVDC MaxSine</td>
<td>Combined PWM and multi-level</td>
<td>1%</td>
</tr>
<tr>
<td>HVDC Plus</td>
<td>MMC</td>
<td>1%</td>
</tr>
</tbody>
</table>

The HVDC Light losses are primarily estimated from [112], produced by ABB. The estimated numbers for HVDC plus and MaxSine are both taken from [7], as their designs are similar. With the evolution of converter topology, converter losses will decrease due to, amongst other things, the reduced switching frequency. However, at present, this is still higher than the conventional LCC, which is at 0.8% or so per converter.

**B3. VSC Capability Curve**

There are mainly three factors that affect the real and reactive power capability of VSC HVDC systems:

i. Maximum valve current (IGBT current),

ii. Maximum DC voltage,

iii. Maximum DC current.

According to the equivalent circuit that represents a grid connected MMC in Fig. B9, the equations for the VSC output powers are:

\[
P_c = \frac{V_c V_{PCC}}{X_{TP} + X_s / 2} \sin \theta \quad \text{and} \quad Q_c = j \frac{V_c^2 - V_c V_{PCC} \cos \theta}{X_{TP} + X_s / 2}
\]  

(B1)
From the above equations, the theoretical VSC PQ capability curve can be plotted as shown in Fig. B10 left. The converter maximum real power is lower than the rated MVA, allowing some degree of reactive power capability when operating at the maximum real power. However, when the limitation factors are taken into consideration, the PQ capability curve is modified as Fig. B10 right. The reactive power capability is mainly dependent on the voltage difference between the PCC bus voltage the converter AC side voltage. Therefore, the reactive power capability will decrease with an increasing PCC voltage.
Appendix C

AC and DC Model Equations

C1. Sixth Order Generator Equations

\[
\frac{d}{dt} E'_{q} = \frac{1}{T_{do}'} \left[ -E'_{q} - \left( X_{d} - X_{d}' \right) \left( I_{d} - \frac{X_{d}'}{X_{d}'} \left( \psi_{1d} + \left( X_{d} - X_{is} \right) I_{d} - E'_{q} \right) \right) + E_{fd} \right]
\]

\[
\frac{d}{dt} E'_{d} = \frac{1}{T_{qr}'} \left[ -E'_{d} + \left( X_{q} - X_{q}' \right) \left( I_{q} - \frac{X_{q}'}{X_{q}'} \left( \psi_{2q} + \left( X_{q} - X_{is} \right) I_{q} + E'_{d} \right) \right) \right]
\]

\[
\frac{d}{dt} \psi_{1d} = \frac{1}{T_{do}''} \left[ -\psi_{1d} + E'_{q} - \left( X_{d} - X_{d}' \right) I_{d} \right]
\]

\[
\frac{d}{dt} \psi_{2q} = \frac{1}{T_{qr}''} \left[ -\psi_{2q} - E'_{d} - \left( X_{q} - X_{q}' \right) I_{q} \right]
\]

\[
\frac{d}{dt} \delta = 2\pi f_{0} \left( \Delta\omega - \Delta\omega^{ref} \right)
\]

\[
\frac{d}{dt} \Delta\omega = \frac{1}{2H} \left[ T_m - D\Delta\omega - P_r \right]
\]

The algebraic equations defining the stator voltages and generator electrical real power are given below, assuming that the generator armature resistance is negligible.

\[
V_{q} = V \cos (\delta - \Theta) = \frac{X_{q}'' - X_{is}}{X_{q}'} E'_{q} + \frac{X_{q}'' - X_{q}'}{X_{q}'} \psi_{1d} - X_{q}'' I_{d}
\]

\[
V_{d} = V \sin (\delta - \Theta) = + \frac{X_{d}'' - X_{is}}{X_{d}'} E'_{d} - \frac{X_{d}'' - X_{q}'}{X_{d}'} \psi_{2q} + X_{q}'' I_{q}
\]

\[
P_{e} = V_{q} I_{q} + V_{d} I_{d}
\]

\[
V = \sqrt{V_{q}^2 + V_{d}^2}
\]

where all notations in the above equations are in consist of [113].
C2. Generator Saturation Characteristics

The saturation characteristics of a synchronous generator defined in DlgSILENT PowerFactory is given by parameters SG1.0 and SG1.2. These parameters can be calculated from the open circuit saturation curve which is normally the only saturation data available. In this case, the example data listed below, which is provided for the generators in the two-area system model, is used to demonstrate how the saturation characteristic is defined. The data is given as:

\[ A_{sat} = 0.015 \quad B_{sat} = 9.6 \quad \psi_{T1} = 0.9 \]

Under no-load rated speed conditions, the open circuit characteristic relating terminal voltage and field current gives the saturation characteristic. The saturation curve can be divided into two segments: unsaturated segment I and nonlinear segment II. The threshold value \( \psi_{T1} \) defines the boundary for these two segments as shown in the figure below:

For segment I, \( \psi_I = 0 \), the slope of the air-gap line \( L_{adu} \) is the unsaturated values of \( L_{ad} \), which equals to 1.6 as given in [20].

For segment II, \( \psi_I \) can be defined by a mathematical function:

\[ \psi_I = A_{sat} e^{B_{sat} (\psi_a - \psi_{T1})} \quad \text{(C1)} \]

However, the definition of the saturation curve in DlgSILENT PowerFactory is different, as shown in (2) in Fig. C1. Its characteristic is given by specifying the excitation currents \( I_{1,0} \) and \( I_{1,2} \), which are needed to obtain 1 p.u and 1.2 p.u of the
rated generator voltage under no-load conditions, respectively. Applying the provided parameter values into the above equation gives:

\[ \psi_{I10} = A_{sat} e^{B_{sat} (1-\psi_{R1})} = 0.04 \]
\[ \psi_{I20} = A_{sat} e^{B_{sat} (1.2-\psi_{R1})} = 0.267 \]

Therefore \( I_{1.0} \) and \( I_{1.2} \) can be derived as:

\[ I_{1.0} = \frac{1 + \psi_{I10}}{L_{adu}} = 0.65 \quad I_{1.2} = \frac{1.2 + \psi_{I12}}{L_{adu}} = 0.917 \quad I_0 = \frac{1}{L_{adu}} = 0.625 \]

As defined by DIgSILENT PowerFactory technique reference, the value of the parameters for generator saturation characteristic in DIgSILENT PowerFactory is calculated as:

\[ SG_{I.0} = \frac{I_{1.0}}{I_0} - 1 = 0.039 \]
\[ SG_{I.2} = \frac{I_{1.2}}{1.2I_0} - 1 = 0.223 \]

### C3. Network dq0 Transformation

The transformation contains two parts: Clarke and Park transformations. In the case of balanced three-phase circuits, application of the dq0 transform reduces three AC quantities to two DC quantities. This simplifies the calculation in the system, and an inverse transform is used to recover the actual three-phase AC quantities. The Clarke transformation (alpha-beta transformation) for three-phase power system elements has the form of:

\[
\begin{pmatrix}
  v_a \\
  v_\beta \\
  v_0
\end{pmatrix} = k
\begin{pmatrix}
  1 & -1 & -1 \\
  0 & \sqrt{3} & \sqrt{3} \\
  1 & 1 & 1
\end{pmatrix}
\begin{pmatrix}
  v_a \\
  v_b \\
  v_c
\end{pmatrix}
\]

(C2)
The three-phase voltages in a balanced AC system are given as:

\[ v_a(t) = \sqrt{2}v\cos(\theta(t)) \]
\[ v_b(t) = \sqrt{2}v\cos(\theta(t) - \frac{2}{3}\pi) \]
\[ v_c(t) = \sqrt{2}v\cos(\theta(t) + \frac{2}{3}\pi) \]

where \( v \) is the RMS value. In the case of \( k=2/3 \). Applying the Clarke transformation gives:

\[ v_\alpha = \sqrt{2}v\cos \theta(t) \]
\[ v_\beta = \sqrt{2}v\sin \theta(t) \]
\[ v_\gamma = 0 \]

This is equivalent to the phasor representations (\( v_{\text{real}} \) and \( v_{\text{imaginary}} \)) of the voltages which are commonly used in a balanced AC system. This is known as the magnitude invariant transformation. Additionally, when \( k=\sqrt{(2/3)} \), the transformation results:

\[ v_\alpha = \sqrt{3}v\cos \theta(t) \]
\[ v_\beta = \sqrt{3}v\sin \theta(t) \]
\[ v_\gamma = 0 \]

In this case the amplitudes of the transformed voltages are not the same, which is different from the case of magnitude invariant transformation. This is referred to as the power invariant transformation. To further transform the phasor representations into DC components, the Park transformation is applied. The transformation and its reverse form are given as:

\[
\begin{pmatrix}
v_d \\
v_q
\end{pmatrix} =
\begin{pmatrix}
\cos \theta & \sin \theta \\
-\sin \theta & \cos \theta
\end{pmatrix}
\begin{pmatrix}
v_\alpha \\
v_\beta
\end{pmatrix} \tag{C3}
\]

\[
\begin{pmatrix}
v_\alpha \\
v_\beta
\end{pmatrix} =
\begin{pmatrix}
\cos \theta & -\sin \theta \\
\sin \theta & \cos \theta
\end{pmatrix}
\begin{pmatrix}
v_d \\
v_q
\end{pmatrix} \tag{C4}
\]
where angle $\theta$ is the angle of a reference dq frame. This angle can be different in an integrated AC/DC system model. The transformation between different dq reference frames in a large AC/DC system is given below. Assuming a network frame (D-Q) with reference angle $\theta$, and a generator or a converter reference frame (d-q) with reference angle $\alpha$, we have:

$$\sigma = \alpha - \theta$$ (C5)

$$\begin{pmatrix} v_D \\ v_Q \end{pmatrix} = \begin{pmatrix} \cos \theta & \sin \theta \\ -\sin \theta & \cos \theta \end{pmatrix} \begin{pmatrix} v_\alpha \\ v_\beta \end{pmatrix}$$ (C6)

$$\begin{pmatrix} v_d \\ v_q \end{pmatrix} = \begin{pmatrix} \cos \alpha & \sin \alpha \\ -\sin \alpha & \cos \alpha \end{pmatrix} \begin{pmatrix} v_\alpha \\ v_\beta \end{pmatrix} = \begin{pmatrix} \cos(\theta + \sigma) & \sin(\theta + \sigma) \\ -\sin(\theta + \sigma) & \cos(\theta + \sigma) \end{pmatrix} \begin{pmatrix} v_\alpha \\ v_\beta \end{pmatrix}$$

$$= \begin{pmatrix} \cos \sigma & \sin \sigma \\ -\sin \sigma & \cos \sigma \end{pmatrix} \begin{pmatrix} \cos \theta v_\alpha + \sin \theta v_\beta \\ -\sin \theta v_\alpha + \cos \theta v_\beta \end{pmatrix}$$

$$= \begin{pmatrix} \cos \sigma & \sin \sigma \\ -\sin \sigma & \cos \sigma \end{pmatrix} \begin{pmatrix} v_D \\ v_Q \end{pmatrix}$$ (C7)

The above transformation allows conversions between different dq reference frames, and thus dq domain calculations can be carried out throughout a large system model.

**C4. Linearized VSC HVDC Link Equations**

![Diagram of VSC HVDC link](image)

Fig. C2 Point-to-point VSC HVDC link.

The linearized converter model for a point-to-point VSC HVDC link used in the test systems in this thesis is provided in this section. VSC1 is configured to maintain a constant DC link voltage (feedback DC voltage control) and constant reactive power.
Appendix C

\( Q = 0 \) (feedback Q control). VSC2 is configured for real and reactive power control (feedback PQ controls). The inner vector current controllers take the form of \( k_{dq}(1 + 1/T_{dq}) \). The outer loop controllers take the form of \( kp + ki/s \).

The state equations for converter plant model are:

\[
\begin{align*}
L_{d} \dot{i}_d &= -R_{d}i_d + \omega L_{q}i_q + e_d - v_d \\
L_{q} \dot{i}_q &= -R_{q}i_q - \omega L_{d}i_d + e_q - v_q \\
V_{dc} &= -(e_{d}i_{d} + e_{q}i_{q}) + \frac{I_{dc}}{C_{eq}V_{dc}}
\end{align*}
\]  

(C8)  

(C9)  

(C10)

The controller state equations are:

\[
\begin{align*}
\dot{x}_d &= \frac{k_d}{T_d}(i^*_{d} - i_d) \\
\dot{x}_q &= \frac{k_q}{T_q}(i^*_{q} - i_q) \\
\dot{x}_{dc} &= k_{i_{dc}}(V_{dc}^* - V_{dc}) \quad \text{or} \quad \dot{x}_p = k_{i_{p}}(P^* - P) \\
\dot{x}_Q &= k_{i_{Q}}(Q^* - Q)
\end{align*}
\]

Four additional state variables are introduced for the controllers. The internal variables can be expressed by equations:

\[
\begin{align*}
e_d &= k_d(i^*_d - i_d) + x_d - \omega L_{q}i_q + v_d \\
e_q &= k_q(i^*_q - i_q) + x_q + \omega L_{d}i_d + v_q \\
i^*_d &= k_{p_{dc}}(V_{dc}^* - V_{dc}) + x_{dc} \quad \text{or} \quad i^*_q = k_{p_{p}}(P^* - P) + x_p \\
i^*_q &= k_{p_{Q}}(Q^* - Q) + x_Q
\end{align*}
\]

Some other associated VSC HVDC link parameters are provided as:

i. DC lines parameters: \( R_{dc} = 0.0113 \ \Omega/km, \ L_{dc} = 0.466 \text{mH/km} \).

ii. Paralleled DC side equivalent capacitor is estimated as: \( C_{eq} = 150 \mu\text{F} \), operating at ±320kV.

iii. Connection transformer \( T_{c} \): 230kV/325.73kV with short circuit voltage 15%.

iv. Converter equivalent AC coupling phase reactors: \( R=0.005p.u., \ X=0.15p.u. \).
After linearization, the state space equation for VSC1 with feedback $V_d$-$Q$ control is:

$$
\begin{align*}
\dot{x}_d &= \frac{-(R+k_d V_d) }{L} - \frac{ (R+k_d Q) }{L} i_d - \frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \to - \frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
\dot{x}_q &= \frac{-k_d}{T_d} i_d - \frac{k_d}{T_d} \frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
\dot{i}_d &= \frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
\dot{i}_q &= \frac{-k_d}{T_d} i_d - \frac{k_d}{T_d} \frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
\end{align*}
$$

In matrix form:

$$
\begin{bmatrix}
i_d \\
i_q \\
V_{dc} \\
\dot{x}_d \\
\dot{x}_q \\
\dot{i}_d \\
\dot{i}_q \\
\dot{x}_q \\
\end{bmatrix} =
\begin{bmatrix}
\frac{-k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
\frac{-k_d}{T_d} i_d - \frac{k_d}{T_d} \frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
0 \\
0 \\
0 \\
0 \\
0 \\
0 \\
\end{bmatrix} +
\begin{bmatrix}
\frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
\frac{-k_d}{T_d} i_d - \frac{k_d}{T_d} \frac{k_d}{L} k_{p,dc} V_{dc} + \frac{k_d}{L} V_d - \frac{k_d}{L} Q_i \\
0 \\
0 \\
0 \\
0 \\
0 \\
\end{bmatrix}
$$

$$
\begin{bmatrix}
\frac{v_d}{C_{eq} V_{dc}} \\
\frac{v_q}{C_{eq} V_{dc}} \\
\frac{V_{dc}}{C_{eq} V_{dc}} \\
\frac{Q}{C_{eq} V_{dc}} \\
\end{bmatrix} =
\begin{bmatrix}
\frac{1}{C_{eq}} \\
\frac{1}{C_{eq}} \\
\frac{1}{C_{eq}} \\
\frac{1}{C_{eq}} \\
\end{bmatrix}
$$
The state space equation for VSC2 with feedback PQ controls is

\[
\begin{bmatrix}
    \dot{i}_d \\
    \dot{i}_q \\
    \dot{V}_{dc} \\
    \dot{x}_d \\
    \dot{x}_q \\
    \dot{x}_p \\
    \dot{x}_q
\end{bmatrix} =
\begin{bmatrix}
    \frac{-(R+k_d)}{L} & 0 & 0 & 0 & \frac{1}{L} & 0 & k_d & 0 \\
    0 & \frac{-(R+k_q)}{L} & 0 & 0 & 0 & \frac{1}{L} & 0 & k_q \\
    k_{k_p,d}(P-P^*) - k_{k_p,q}(Q-Q^*) - i_q[k_{k_p,0}(Q' - Q) + k_{k_p,q}(Q' - Q) - k_{k_p,0}Q' + k_{k_p,q}Q'] & 0 & -k_d & 0 & 0 & 0 & k_d & 0 \\
    k_{k_p,d} + 2k_{k_p,d} - x_d - v_d & k_{k_p,q} - k_{k_p,d} + x_d & 0 & 0 & 0 & 0 & 0 & 0 \\
    -k_d & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
    0 & -k_d & 0 & 0 & 0 & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & 0 & 0 & 0 & 0
\end{bmatrix}
\begin{bmatrix}
    i_d \\
    i_q \\
    V_{dc} \\
    x_d \\
    x_q \\
    x_p \\
    x_q
\end{bmatrix}
\]

\[
+ \begin{bmatrix}
    0 & 0 & k_{k_p,d} & -k_{k_p,d} & 0 & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & k_{k_p,0} & -k_{k_p,0} & 0 & 0 \\
    -k_d & 0 & 0 & 0 & -k_d & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
    0 & 0 & k_{k_p,d} & -k_{k_p,d} & 0 & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & k_{k_p,0} & -k_{k_p,0} & 0 & 0 \\
    0 & 0 & k_{p,d} & -k_{p,d} & 0 & 0 & 0 & 0 \\
    0 & 0 & 0 & 0 & k_{p,q} & -k_{p,q} & 0 & 0
\end{bmatrix}
\begin{bmatrix}
    v_d \\
    v_q \\
    P \\
    Q \\
    Q' \\
    L_{dc}
\end{bmatrix}
\]
Appendix D

Data for Developing Dynamic GB System

Detailed data and parameters needed to establish the dynamic GB system are presented in this part together with the specifications of the techniques used during the construction process. For more specific background data of the GB network model, please refer to [71, 72].

<table>
<thead>
<tr>
<th>Abbreviations</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>V</td>
<td>Nominal Voltage</td>
</tr>
<tr>
<td>$P_{\text{gen}}$</td>
<td>Effective generation in the reference load flow case</td>
</tr>
<tr>
<td>$Q_{\text{max}}$ and $Q_{\text{min}}$</td>
<td>Maximum and minimum reactive power capability for each generation</td>
</tr>
<tr>
<td>Shunt gain/loss</td>
<td>The supplied/absorbed reactive power of the installed switched shunts in the load flow reference case</td>
</tr>
<tr>
<td>SVC $Q_{\text{lead}}$ and $Q_{\text{lag}}$</td>
<td>The reactive power capability of the installed SVCs</td>
</tr>
<tr>
<td>$I^R, I^X$</td>
<td>The active and reactive power transmission losses on the lines within the reduced parts of the network</td>
</tr>
<tr>
<td>Bint</td>
<td>Shunt gains from the lines on the reduced parts of the network</td>
</tr>
<tr>
<td>R,X,B</td>
<td>Resistance, reactance, and susceptance of the transmission lines in per unit values with a base of 100MVA</td>
</tr>
<tr>
<td>TF</td>
<td>Transformers that are placed in some branches and there are quadrature boost transformers (QB TF) in double circuits 1-3 and 12-18 with 2 degree phase shifts for the load flow solution</td>
</tr>
<tr>
<td>$P_{\text{load}}, Q_{\text{load}}$</td>
<td>Active and reactive power of loads</td>
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The frequency and time base for the following data is 50Hz and 1s respectively.
### Appendix D

#### D1. Steady-state Data

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1 Interconnector 5 is not considered in the reference load flow case
**Appendix D**

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## Appendix D

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Diagram of comparative load flow for the GB system [71].
D2. Dynamic Data

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<td>0.043</td>
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<td>$T_{qe}'$ s</td>
<td>0.071</td>
<td>0.08</td>
<td>0.152</td>
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<td>0.08</td>
<td>0.15</td>
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Excitation system data

Excitation System DC1A/ST1A Parameters

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<tr>
<th>$T_R$ (s)</th>
<th>$K_A$</th>
<th>$T_A$ (s)</th>
<th>$T_E$ (s)</th>
<th>$K_E$</th>
<th>$V_{Rmax}/V_{Rmin}$</th>
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<tr>
<td>0.01</td>
<td>40</td>
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<td>$S_E=A_ex^eBex^K_F\frac{1}{T_F}(s)$</td>
<td>$K_F$</td>
<td>$T_F$ (s)</td>
<td>$T_r$</td>
<td>$K_a$</td>
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<td>$A_ex=0.07$</td>
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<td>0.1</td>
<td>1</td>
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<td>Note: A value for $K_E = 1$ is used to represent a separately excited exciter.</td>
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Turbine governor data

Hydraulic and Steam Turbine Parameters

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<thead>
<tr>
<th>$R_p$</th>
<th>$T_e$ (s)</th>
<th>$T_M$ (s)</th>
<th>$T_G$ (s)</th>
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<tbody>
<tr>
<td>0.05</td>
<td>2</td>
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<td>$R$</td>
<td>$F_{HP}$</td>
<td>$T_{BH}$ (s)</td>
<td>$T_{CH}$ (s)</td>
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## Allocation of selected generation types

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<th>Excitation Type</th>
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<td>DC1A</td>
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<td>3</td>
<td>H11</td>
<td>9</td>
<td>DC1A</td>
</tr>
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<td>4</td>
<td>F15</td>
<td>7</td>
<td>DC1A</td>
</tr>
<tr>
<td>5</td>
<td>N3</td>
<td>2</td>
<td>ST1A</td>
</tr>
<tr>
<td>6</td>
<td>WF</td>
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<td>10</td>
<td>CF2</td>
<td>19</td>
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<td>F15</td>
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### Generation of heavy and light loading conditions

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Appendix E

List of Publications


[C2] L. Shen, M. Barnes, and J. V. Milanović, "Interactions between STATCOM and VSC HVDC in dynamic GB system," 7th IET International Conference on Power Electronics Machines and Drives (PEMD), April, 2014


