Primary Frequency Response by MTDC Offshore Grids

Master of Science Thesis Sustainable Energy Technology

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Summary

The preferred technology for connecting far from shore offshore wind plants to the onshore AC power system is the voltage-source converter based high voltage direct current (VSC-HVDC) transmission system. There is a large number of advantages, namely, the decoupled active and reactive power control, the capability to reverse power flows without changing voltage polarity and finally, the capability to operate in weak and isolated power systems. Beside the above mentioned advantages, HVDC systems are capable to transport large amounts of power within large distances. The minimal cable power loss makes it desirable to use HVDC technologies in order to transport electrical power for distances above 60 km.

Future power systems are expected to include large in-feed of power electronic based generation as a result of converter interfaced renewable energy resources. Furthermore, the construction of a Pan-European HVDC transmission network, mainly used as bulk transmission system, will enable the interconnection of previously asynchronous systems in a multi-terminal DC grid. Furthermore, it will enable large offshore wind power plants to be part of this MTDC grid. However, even if it seems that the onshore AC power systems are inter-connected in a MTDC grid, the HVDC converters forming part of the MTDC network will decouple the AC power system dynamics. Having the networks decoupled, in case of disturbances such as faults, tripping of generation unit, puts the system’s frequency stability into greater risk.

The present thesis deals with the study of different methods of providing primary frequency response by making use of the multi-terminal direct current (MTDC) network. The AC systems’ primary frequency response is investigated, and controllers for provision of primary response are proposed. To this purpose, two configurations have been studied, a point-to-point and a multi-terminal topology. In both situations an offshore wind park is connected, through VSC-HVDC transmission, to one or more onshore AC power systems, modelled by single machine dynamic model. The time-average, instantaneous value modelling approach is used for the VSC-HVDC system; it contains control systems, phase-locked loop and detailed representation of DC transmission lines.

The controllers proposed for the primary frequency response study are: a frequency droop controller which provides primary frequency response, a synthetic inertia emulation controller implemented on the DC voltage control loop of the HVDC converter and finally, a synthetic inertia controller using the frequency derivative, directly measured at the grid connection point. Since the power injection by a voltage-source converter can be controlled, the above mentioned controllers can be used to assist the frequency response of the AC power systems.

Following a disturbance (i.e. trip of a unit), the frequency droop control method utilizes the deviation in system frequency from the nominal value, to adjust the power being supplied to the AC area. The synthetic inertia emulation controller employs the energy stored in the capacitors to emulate inertia response by changing the DC link voltage reference, based on the variation of the AC system’s frequency. In a MTDC scheme, such a method can be used to provide exchange of primary frequency reserves between asynchronous areas. The last control method uses the frequency derivative to control the active power in the converters, to strengthen the primary frequency response of the AC system undergoing a disturbance. Finally, sensitivity analysis of the above control parameters is performed to investigate various interactions between the AC and the DC system.
Nomenclature and Abbreviations

AC – Alternating current
AGC – Automatic generation control
CSC – Current source converter
DC – Direct current
GSVSC – Grid side voltage source converter
GTO – Gate Turn-off Thyristor
HVDC – High voltage direct current
IGBT – Insulated Gate Bipolar Transistor
IGCT – Integrated Gate Commutated Thyristor
LCC – Line commutated converter
MTDC – Multi-terminal direct current
NADIR – Frequency excursion from nominal value
PCC – Point of common coupling
PI – Proportional Integral
PWM – Pulse Width Modulation
ROCOF – Rate of change of the frequency
VSC – Voltage source converter
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<tr>
<td>$U_S$</td>
<td>Grid voltage</td>
</tr>
<tr>
<td>$U_C$</td>
<td>Converter voltage</td>
</tr>
<tr>
<td>$U_{dcj}$</td>
<td>DC voltage at terminal j</td>
</tr>
<tr>
<td>$C_{dc}$</td>
<td>Capacitance of the HVDC cable</td>
</tr>
<tr>
<td>$P_{dcj}$</td>
<td>Active power of the converter at the DC side at terminal j</td>
</tr>
<tr>
<td>$I_{dcj}$</td>
<td>Current injection at the terminal j</td>
</tr>
<tr>
<td>$R_{dc}$</td>
<td>Resistance of the HVDC cable</td>
</tr>
<tr>
<td>$L_{dc}$</td>
<td>Inductance of the HVDC cable</td>
</tr>
<tr>
<td>$I_M$</td>
<td>Incidence matrix</td>
</tr>
<tr>
<td>$m_a$</td>
<td>Modulation index</td>
</tr>
<tr>
<td>$T_{A+/+}$</td>
<td>Switching devices used in the voltage-source converter</td>
</tr>
<tr>
<td>$D_{A+/+}$</td>
<td>Anti-parallel diodes corresponding to the switching devices</td>
</tr>
<tr>
<td>$\delta$</td>
<td>Angle between the grid voltage and the converter voltage</td>
</tr>
<tr>
<td>$R_{chopper}$</td>
<td>Chopper resistance</td>
</tr>
<tr>
<td>$C_{VSC}$</td>
<td>Capacitance of the VSC station</td>
</tr>
<tr>
<td>$i_{d,ref}$</td>
<td>Reference d-axis component of the current</td>
</tr>
<tr>
<td>$i_{q,ref}$</td>
<td>Reference q-axis component of the current</td>
</tr>
<tr>
<td>$i_d$</td>
<td>d-axis component of the current measured at PCC</td>
</tr>
<tr>
<td>$i_q$</td>
<td>q-axis component of the current measured at PCC</td>
</tr>
<tr>
<td>$U_{cd}$</td>
<td>d-axis converter voltage</td>
</tr>
<tr>
<td>$U_{cq}$</td>
<td>q-axis converter voltage</td>
</tr>
<tr>
<td>$k_i$</td>
<td>Integral gain of the PI controller</td>
</tr>
<tr>
<td>$k_p$</td>
<td>Proportional gain of the PI controller</td>
</tr>
<tr>
<td>$P_c$</td>
<td>Active power of the converter</td>
</tr>
<tr>
<td>$P_c,ref$</td>
<td>Active power reference of the converter</td>
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<tr>
<td>$Q_c$</td>
<td>Reactive power of the converter</td>
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<td>$Q_c,ref$</td>
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</tr>
<tr>
<td>$f_{ref}$</td>
<td>Reference frequency used in the frequency droop controller</td>
</tr>
<tr>
<td>$P_{OWP}$</td>
<td>Power of Offshore Wind Park</td>
</tr>
<tr>
<td>$H$</td>
<td>Inertia constant of an electrical machine</td>
</tr>
<tr>
<td>$W_{kinetic}$</td>
<td>Kinetic energy stored in a generator's rotor</td>
</tr>
<tr>
<td>$S_{machine}$</td>
<td>Nominal rating of an electrical machine</td>
</tr>
<tr>
<td>$J$</td>
<td>Total moment of inertia</td>
</tr>
<tr>
<td>$\omega_{SM}$</td>
<td>Rated mechanical speed of the electrical machine</td>
</tr>
<tr>
<td>$W_{static}$</td>
<td>Electro-static energy stored in the capacitor</td>
</tr>
<tr>
<td>$N$</td>
<td>Number of DC capacitors</td>
</tr>
<tr>
<td>$S_{VSC}$</td>
<td>Power rating of the VSC converter</td>
</tr>
<tr>
<td>$P_M$</td>
<td>Mechanical power of the electrical machine</td>
</tr>
<tr>
<td>$P_E$</td>
<td>Electrical power of the electrical machine</td>
</tr>
<tr>
<td>$P_m$</td>
<td>Power input of the VSC</td>
</tr>
<tr>
<td>$P_{out}$</td>
<td>Power output of the VSC</td>
</tr>
<tr>
<td>$H_{VSC}$</td>
<td>Inertia constant for the HVDC system</td>
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1. Introduction

1.1. Background considerations

A strong interest in the utilization of new power generation technologies has arisen as a result of the increase in electricity demand and the continuous depletion of fossil fuels. Another important factor is the increasing concern for the environmental impact of the currently fossil fuel based conventional generation. [1] Hence, the reduction of the levels of the greenhouse gases is considered an additional important criterion in any technological domain. Therefore, the focus has been set on utilization of the renewable energy technologies [2].

Wind power is considered to be a mature technology and available for large scale installation. It can be divided in two main sections, the onshore and the offshore wind power industries. [1] Due to higher wind regimes, large available space and less interference with the population, offshore wind generation will be much preferred to the onshore in the future. However, due to large distances from shore, the problem becomes one of transporting the wind power generation, with as fewer losses as possible. Below distances of 50 - 60 km from shore [3], [4], AC cables are securely used for transmission. The advantage of an AC connection for offshore wind power plants is the low investment cost. However, by increasing the distance, cable cost will become significant and demand for large amounts of reactive power compensation, making it less economically attractive. [4] Therefore, for distances larger than 50-60 km, [4] it is desirable to use DC lines for the transmission of the electrical energy, and implicitly the use of converters is needed for the AC-DC connection.

The advantage of a DC connection is the lower cable losses above the distance of 50-60 km. [4] In addition, DC transmission adds more controllability to the power system. [5] As a non-technical feature, it is easier to install offshore DC cables rather than AC, because fewer joints are needed, while for above ground AC cable installation more regulations exist [3]. The drawback is the relevant higher investment cost with respect to the AC cable transmission, due to the cost of the converters.

An example of a HVDC connection of an offshore park to an onshore system is the BorWin1 project, in Germany. A DC connection has been employed for the project since the distance between the offshore wind power plant and the onshore grid connection point is larger than 200 km, from which 75 km are onshore, using underground cables, and the rest of 125 km are offshore, using submarine cable. The capacity of the HVDC cables is 400 MW, with a voltage of ±150kV. The BorWin1 project has been in operation since December, 2010 [6] [7].

There are two main HVDC technologies used, either the classical technology of line commutated converters (LCC) or the new generation of the voltage source converter (VSC) based technology. The LCC converters are mainly used in point-to-point DC connections between countries. The VSC technology is considered more suitable for wind power integration. There are many advantages of VSC-HVDC over LCC, namely the capability of independent active and reactive
power control, the capability of changing power flow direction while maintaining DC voltage polarity, as well as independence from inter-converter communication and self-commutation [8].

For a complex transnational grid, as the Pan-European network, the advantages of using the VSC-HVDC over the LCC technology are considerate, especially when connecting offshore wind power plants. Such a multi-terminal network would improve the power trading between countries as well as supply power from the offshore plants to the systems. Due to the renewable technologies and the Pan-European network, the future power systems will include more high power converters. [9] However, there are still technological challenges that need to be addressed for the integration of high power electronics to the AC systems. These challenges are related to the operation of an AC-DC system and how the AC system stability is influenced especially in case of disturbance conditions (i.e. faulted conditions followed by trip of conventional units) [10].

An important aspect of the operation of AC systems is that at any given moment in time, the power produced needs to match the power being consumed. For constant demand, if less power is produced frequency will decrease, while if more power is produced the frequency will increase. Under normal operation this balance is maintained, hence frequency remains constant. However, in case of fault or disturbance conditions, the balance is lost and the system’s frequency will change at a rate determined by the total system inertia. Synchronous generators and fixed wind speed turbines contribute to the total system inertia. Contrary, variable wind speed turbines are decoupled from the AC systems and offer no contribution, due to the power electronics used for the control mechanisms [11] [12]. For all frequency deviations, grid codes have been established for normal operating conditions, in order to prevent cascade effects, black-outs or collapse of entire systems [13] [14]. Therefore, MTDC converters will be required to comply with the regulations and provide frequency response [9] [15].

The power systems maintain their current inertial response even though the installed capacity will increase. If the renewable energy technologies begin to replace the existing ones the stability of the AC systems will be jeopardized. The power system’s capability of overcoming a disturbance is an important concern and the system’s security and reliability is under-discussion. [16]

Future plans include the construction of a MTDC grid which would form an over-lay European DC network extending in a large geographical area. These DC networks would inter-connect previously asynchronous power systems. Such an example is the MTDC connection of the Great Britain power system to the continental Europe power system. Therefore, when having meshed AC-DC networks, in order to engage the MTDC grids to participate in the share of frequency response, extra control actions need be employed. Hence, the frequency deviations of the asynchronously MTDC connected AC power systems remain close to each other when a contingency occurs or in other words the AC systems share their primary frequency reserves.

Such controls include frequency droop control, synthetic inertia emulation control, and synthetic inertia control that uses the frequency derivative. Other control methods use the kinetic energy stored in the wind power plants generators, in order to provide additional power from the DC link to the area under disturbance [8] [14] [17]. From the controllers mentioned the latter will not be discussed in the present thesis.
At a contingency event, the frequency deviation is used by the controllers to activate exchange of primary reserves between AC grids connected through the MTDC grid. The goal is to create an artificial coupling in order to stabilize the network frequencies for a short time period, by minimizing the deviation of the nominal AC frequency and sharing the burden between the converter stations, until it can be corrected through the already known and used governors.

1.2. Thesis objectives

With the MTDC grid becoming more relevant for connecting offshore wind power plants to the onshore grid connection point and the preferred technology being the VSC-HVDC system, there are still some challenges that need to be overcome. Introducing power electronic based generation to the power system will affect the system’s frequency response capability by decoupling the AC systems. VSC-HVDC systems replacing conventional generation units will decrease the total inertia of a system. Therefore, the capability to overcome frequency deviations will be negatively impacted, thus jeopardizing the security and reliability of the AC system. However, with multi-terminal HVDC systems that use additional frequency controllers in the VSCs, the decoupled AC systems may exchange power reserves and can help improve the primary frequency response.

The aim of the present thesis is to study the interactions between the AC and DC systems, especially in disturbance conditions, in order to quantify the impact on the AC system’s stability. This is attained using instantaneous values models, with the tests being performed for various scenarios. For the study of the frequency response of a system, disturbance conditions, such as unit generation loss and power consumption increase, have been investigated. In order to study interactions between AC and DC systems, the configurations used are both point-to-point as well as multi-terminal VSC-HVDC networks.

To minimize the frequency deviations in the mentioned conditions, the results of the interactions will be used to design controls for strengthening the AC power systems’ frequency response. The proposed control methods will be implemented at the VSC systems. These are frequency droop controller and synthetic inertia controllers. The frequency controllers’ impact on the frequency response will be studied and compared, in various scenarios. They use the MTDC grid to share the burden that is placed on the AC system, in case of disturbance conditions. The synthetic inertia methods include the frequency controller using the derivative of the frequency and the synthetic inertia emulation controller. The aim is to investigate the strengthening achieved with the controllers, by artificially coupling the AC systems.

1.3. Thesis approach

In order to study the interactions between AC and DC systems and the impact of large penetration of VSC-based HVDC connected wind, models of a VSC-HVDC network connecting a wind park to AC systems have been developed in MATLAB/Simulink. The models are in point-to-point and in multi-terminal configurations. The point-to-point model consists of an AC system connected through the use of power converters and HVDC link to a wind park. The multi-terminal model consists of two AC power systems and a wind park connected through a power HVDC transmission system. The multi-terminal network can have either a radial or meshed configuration.
Firstly, a small isolated single machine AC system containing a generator, a governing system and an excitation system is developed. Secondly, DC connected wind is added to the AC system. The point-to-point and multi-terminal models have been evaluated, with a step up/down in the wind power in-feed to the MTDC system and AC fault, in order to ascertain the validity of the converters and the DC grid.

Having the primary frequency response problem identified, the multi-terminal DC system is used to improve the power exchange between the AC systems. The impact on the frequency response due to the decoupling of the AC systems has been investigated under load change conditions. Simulations have been performed to obtain the AC system response, followed by simulations to investigate the performance of various frequency controllers. The frequency droop method, the synthetic inertia using the frequency derivative method and the synthetic inertia emulation control method have been compared in order to determine the impact on the system frequency response. The sensitivity of the parameters for such controllers has also been studied in order to understand the degree of influence they have on the AC system’s frequency NADIR (Maximum frequency drop) and ROCOF (Rate of change of frequency).

1.4. Thesis contribution

The aim of the present thesis is to investigate the AC systems’ frequency response in various scenarios, and improve it with the additional frequency control loops implemented at the Grid side VSC which are connected in a MTDC grid. The tests performed for the frequency response include load changes that cause the destabilization of the AC system frequency. Sensitivities of the DC voltage controller’s proportional and integral gain are obtained. The sensitivity of the various control parameters for the frequency controllers, have also been tested.

Various methods and control schemes are employed in order to improve the frequency response of the AC system. The methods proposed are compared based on the frequency related metrics such as the NADIR, and the ROCOF. In addition, various configurations of the DC transmission are studied, considering not only the point-to-point scenario but the multi-terminal one as well. With the goal to study AC/DC systems’ interactions, the models used for the simulations are instantaneous value, time-average. The AC systems have been developed using generator models with controls (governors and exciters), the HVDC grid has been modelled with state-space model, while the VSC system employs inner and outer controllers, as well as phase-locked loop (PLL), current limiter and modulation limiter.

1.5. Thesis Outline

The present thesis is organized in seven chapters. Chapter 2 presents an overview of the current technological state and the evolution of the system components. Chapter 3 continues with the presentation of the modelling used for the system components as well as the control methods employed in the multi-terminal VSC-HVDC networks.

Chapter 4 elaborates the frequency control of an AC grid and details both the frequency droop method as well as the synthetic inertia methods. Chapter 5 presents the tests and results obtained for the model validation.
Chapter 6 shows the frequency response for all the implemented controllers, the interaction of the AC and DC systems in the multi-terminal HVDC topology.

The final conclusions and future work recommendations are presented in Chapter 7.
2. Technological overview

2.1. Wind power technology

The wind turbines are considered one of the most mature renewable energy technologies due to the advances made in the energy output per turbine, which at good sites make the wind power systems competitive to the fossil fuel technologies. Wind turbines have increased in size around 10 - 12 times and in unit capacity they have reached 2 MW. It is expected that the near future will have wind turbines with a power output of 10 – 12 MW [1]. The noise emitted during operation has also been reduced to half in the past years. Since the technology is economically efficient and largely accessible, the global installed capacity increases greatly every year, with an average of 20% per year, although the exact values vary [1].

![Cumulative Global Wind Power Capacity](image)

Figure 1 Cumulative Global Wind Power Capacity [1]

There are two main types of wind turbine, the horizontal axis and the vertical axis. For large applications, such as offshore wind power plants, the horizontal axis wind turbines are the preferred technology. The wind turbines convert the wind energy into electrical energy with the use of a horizontal rotor, with three blades with a variable pitch angle that control the rotational speed of a linked shaft [1].

Even though the wind power capacity has increased yearly, most of the installed wind power parks are situated onshore. Compared to the conventional generation the capacity is relatively small. However, the trend is that the future would include offshore wind generation, since it offers large space of installation and the visual and noise pollution are limited [18].
2.2. HVDC technologies

HVDC technologies have become more attractive for grid connection of offshore wind power plants. Due to the larger distances from shore, AC cables are not the best option for the energy transmission. For distances larger than 60 km, [4] the capacitance of the AC transmission leads to an increase in the reactive power, which leads to an increase in losses. Therefore, above the distance of 60 km, the preferred method of transporting the electrical power is by using HVDC technologies. This will ensure a minimal cable power loss [19].

Initially, AC power systems were inter-connected only to aid in case of emergency and international trading has not been considered. More recently, with the increase in trading the weak AC tie-lines can become overloaded. The use of HVDC systems will offer operational advantages to the existing power grid, by sharing the burden. [19] Other advantages of the HVDC technologies is that they offer a defined and controlled power flow as well as provide a decoupling, which can protect the voltage of one AC system from a fault in another.

There are two main HVDC technologies that can be considered. The first, using thyristors, is the classical line-commutated converter HVDC (LCC-HVDC). The second type of transmission is the newer technology, the voltage-source converter HVDC (VSC-HVDC), which employs IGBTs switching devices. It has been developed during the mid-90s. [20] The two types of converters have not replaced one another but continue to exist because their application areas are different. The preferred use for the LCC-HVDC technologies is for long distance bulk point-to-point connections with submarine cables, while the VSC-HVDC technologies are preferred for connecting offshore wind power plants [8] [10].

The LCC-HVDC transmission could be used for high power transmission with both reliability and availability guaranteed by 40 years of service experience. The disadvantage of the technology is that it requires a commutation voltage, usually supplied by a synchronous compensator. The LCC cannot operate properly if the AC system short circuit ratio is low. Another drawback of the LCC technology is that it requires AC harmonic filters. These extra components make the station of a LCC-HVDC converter twice in size than a VSC station [20]. The LCC is also limited to one current flow direction through each converter, and in order to achieve reverse in power flow, the voltage polarity must be reversed as well, implying the deactivation of the HVDC line. The largest application for this technology is the Itaipu system in Brazil, at a power level of 6300 MW [21].

The state-of-the-art technology, the VSC does not require a voltage polarity change in order to have a reversed power flow through the converter. Furthermore, it enables the connection to very weak systems with low short circuit power ration. This is a very important feature that has made the VSC technology preferred in connecting offshore wind parks to the AC grid. Another important advantage for the VSC technology is that it is self-commutating; therefore it doesn’t require an external voltage source for its operation. In addition, an important characteristic of the VSC transmission is that the active and reactive power can be independently controlled. The VSC does not require reactive power compensation or large filters to reduce the harmonic distortion. This makes the VSC stations more compact than the LCC ones, and therefore they require an easier offshore installation. The mentioned reasons make the VSC transmission attractive for
wind farms connection, since the voltage at the AC end can be controlled and power can be transmitted to the wind farm with little or no wind [22]. The capability to independently control the active and reactive powers is an important factor in aiding the AC system frequency response.

A multi-terminal DC network means a HVDC network interlinked with at least three converters. A multi-terminal HVDC translational grid connects two or more AC national power systems. The VSC-HVDC is the suitable connection for the offshore wind parks due to the use of a common DC voltage, which makes the building and controlling of parallel connections much easier. Hybrid schemes, with both VSC and LCC in the same MTDC have also been a research topic within the last years but not proved mature. As a result the VSC is considered the strongest candidate for MTDC grids. It has been a lot research and development concentrated on this technology in the recent years, however it is still not matured and it still needs more understanding. The main control methods that can be implemented, for a VSC-HVDC system, are the dedicated DC slack bus control (known as master-slave control), the voltage margin control method and the DC voltage droop control [3] [4].

2.3. The VSC operation and applications

The voltage source converter (VSC) is an AC/DC converter through which the power flow is reversible. The continuous progress in the field of high-power fully controlled semiconductors has permitted the increasing penetration of power electronics in the power systems. As mentioned, the LCCs, also called the current-source converters, use thyristors as a technology, while the VSCs uses IGBT transistors. The importance of the transistors used for voltage-source converters is given by their function in pulse-width modulation (PWM), operating at higher frequencies. The IGBTs are self-commutated via a gate pulse. It is desirable that the VSC application generates PWM waveforms of higher frequency when compared to the thyristor-based systems; however, the frequency is also determined by the switching losses [7], [23].

Important applications for voltage source converters are reactive power compensation (Flexible AC Transmission Systems -FACTS- devices), high voltage DC transmission (HVDC), dynamic voltage restoration and active power filtering. In the last decades, the VSC technology has been used for medium and high voltage transmission systems, and the VSC–HVDC systems are considered the state of the art technology for transmission of power over large distances. [4] VSC-HVDC are considered effective for power supply to islands, small and isolated remote loads, in-feed to city centers, remote small-scale generation, offshore generation and deep-sea crossing and multi-terminal systems. Wind farms and offshore wind parks are in particular well suited for VSC-HVDC connections [7].

The first application for VSC-based PWM-controlled HVDC using the IGBT technology was installed in March 1997, in Sweden. The project power level is of 3 MW, with a 10 km line and a voltage level of ±10 kV. Other installation worldwide of VSC-HVDC networks are presented in Appendix E [7].

The simplest VSC three-phase topology is the conventional converter, presented in Figure 2. Each leg is identical to a single-phase converter. Each phase has its own control or reference signal. These signals are compared to the triangular carrier signal in order to create the pulses that
switch on/off the IGBTs. The desire is to have a high switching frequency to reduce the harmonic distortion, however due to losses, a compromise is made and switching frequencies are usually between 2-4 kHz. [21]

Figure 2 Three-phase switch mode converter

The anti-parallel diode is employed to ensure a four-quadrant operation of the converter. The dc bus capacitor provides the required storage of energy so that the power flow is controlled and also offers filtering. The converter is controlled through sinusoidal PWM and the harmonics, which occur, are due to the switching frequency of each leg. [7]

Each converter phase leg is connected to the AC system. Filters are also employed on the AC side in order to further reduce the harmonics level. [7]

Figure 3 Generalized two AC voltage sources connected via a reactor

Figure 3 presents two AC voltage sources that are connected through the phase reactor. Considering that one voltage is that of the AC system and one is at the VSC side, at the fundamental frequency, the active and reactive power can be defined (assuming that the reactor is lossless):
where $U_s$ and $U_c$ are the voltage phasors, at the fundamental frequency, and $\delta$ is the phase angle between them [24].

The phase reactor is found on the AC side of the converter. It is a large inductive element that has a small resistance. By controlling the complex current, the active and reactive power can be controlled. The model of the phase reactor is thus very important for VSC HVDC systems. To the AC side of the converter a low pass filter is also added in order to filter the high frequency signals, and thus prevents harmonics from entering the AC network. [19] For the present study, the filter used to reduce the harmonics has not been implemented since time-average modelling of the converter has been used. Further details regarding the modelling can be found in Chapter 3.

In the above equations, $U_s = U_s \angle 0$ is the AC system voltage and $U_c = U_c \angle \delta$ is the converter voltage. The phase angle $\delta$ has a large influence on the active power, while the system voltage has a large influence on the reactive power. Therefore, the active power and reactive power control is almost independent [19].

For the present thesis the phase inductor is modelled as a series inductor, with a value of 0.15 pu. The values generally used for a phase reactor range between 0.1-0.2 pu, therefore an average has been considered [24] [25].
3. Modelling approach of multi-terminal DC grid

The present chapter will present the modelling of the onshore AC system, its components and the \( \pi \)-equivalent HVDC transmission cables. Following, the VSC converter modelling and the controllers involved will be presented. Finally, the modelling of the wind park will be presented.

3.1. AC power system model

The AC system is modelled using the single machine representation. For a primary frequency control response the main responsible components are the speed governor and the synchronous machine. Therefore, components pertaining to the transmission systems have been considered beyond the goal of the present thesis. The model, while simplified in its form allows an accurate implementation of an AC system’s frequency response. The AC system is modelled in Matlab Simulink with the SimPowerSystems toolbox, using single machine equivalent model.

![Figure 4 Single machine representation of a power system](image)

The synchronous machine generator used is a standard seventh order synchronous generator model. The system is developed using both electrical and mechanical models. The higher the order the more complex the model is. Seventh order model is the most complex and is used for the analysis of dynamic behavior in normal conditions and in case of generator failure. Therefore, by using the SimPowerSystems toolbox and the according synchronous machine a complete static and dynamic analysis can be performed [26]. The entire list of parameters used for the synchronous generators can be found in Appendix A.

The excitation system used for the AC system generator employs a voltage regulator and an exciter as basic elements. The system is developed according to the IEEE standards [27]. It is responsible for regulating the voltage of the generator and the reactive power output. The parameters used in modelling can be found in Appendix A.

The hydraulic turbine and governor used for the simulations and frequency control of the AC system is implemented using a nonlinear hydraulic turbine model, a PID governor system and a servomotor [28]. The prime mover and control system is responsible for the speed regulation and control of energy supply system variables, such as water flow. The system is developed according to IEEE standards. The parameters used for the governor system are found in Appendix A.
3.2. HVDC transmission cables

The HVDC transmission cables have been modelled in such a way that the dynamic DC voltage behavior can be observed. For such a DC transmission line, the π-equivalent model can be used. The line has a defined capacitance, resistance and inductance [21], [29].

![Figure 5 π-equivalent model of the HVDC transmission line](image)

For the above mono-polar HVDC transmission line, the differential equations can be written [22]:

\[
\begin{align*}
C_{dc} \frac{dU_{dc1}}{dt} &= I_{dc1} - I_{12} & \quad 3.2-1 \\
C_{dc} \frac{dU_{dc2}}{dt} &= I_{dc2} + I_{12} & \quad 3.2-2 \\
L_{dc} \frac{dl_{12}}{dt} &= U_{dc1} - U_{dc2} - R_{dc}I_{12} & \quad 3.2-3
\end{align*}
\]

Rearranging the differential equations, the state space form for the mono-polar HVDC transmission line is obtained, as in equation 3.2-4 [30].

\[
\begin{bmatrix}
\frac{d}{dt} [U_{dc1}] \\
\frac{d}{dt} [U_{dc2}] \\
\frac{d}{dt} [l_{12}]
\end{bmatrix} =
\begin{bmatrix}
0 & 0 & -\frac{1}{C_{dc}} \\
0 & 0 & \frac{1}{C_{dc}} \\
\frac{1}{L_{dc}} & -\frac{1}{L_{dc}} & -\frac{R_{dc}}{L_{dc}}
\end{bmatrix}
\begin{bmatrix}
U_{dc1} \\
U_{dc2} \\
l_{12}
\end{bmatrix} +
\begin{bmatrix}
\frac{1}{C_{dc}} & 0 \\
0 & \frac{1}{C_{dc}} \\
0 & 0
\end{bmatrix}
\begin{bmatrix}
I_{dc1} \\
I_{dc2}
\end{bmatrix}
\]

Based on the π-equivalent model of a single mono-polar HVDC transmission line, a state space model can be developed for a generic grid composed of \( j \) VSC stations. The number of nodes will be considered as \( j \) and the number of lines between the nodes will be equal to \( i \). The differential equations that define such a network are [22]:

\[
\begin{cases}
\frac{dx}{dt} = Ax + Bu \\
y = Cx + Du
\end{cases}
\]
The state matrix $x$ is defined as, [30]:

$$x = \begin{bmatrix} U_{dc1} & \cdots & U_{dcj} & I_{\text{line}1} & \cdots & I_{\text{line}i} \end{bmatrix}^T_{1x(j+i)}$$  \hspace{1cm} 3.2-6

And the input vector for the current injections of the network VSCs is:

$$u = \begin{bmatrix} I_{dc1} & \cdots & I_{dcj} \end{bmatrix}^T_{1xj}$$  \hspace{1cm} 3.2-7

Matrix $A$ has the shape:

$$A = \begin{bmatrix} a_{11} & a_{12} \\ a_{21} & a_{22} \end{bmatrix}_{(j+i)x(j+i)}$$  \hspace{1cm} 3.2-8

The sub-matrices for matrix $A$ can be seen below:

$$a_{11} = [0]_{jxj} \hspace{1cm} a_{12} = \left( \frac{1}{L_{dc}} [I]_{jxj} \right)^T_{jxi}$$
$$a_{21} = \left( \frac{1}{R_{dc}} [I]_{jxj} \right)_{ixj} \hspace{1cm} a_{22} = \left( -\frac{R_{dc}}{L_{dc}} [I]_{jxj} \right)_{jxj}$$  \hspace{1cm} 3.2-9

Matrix $B$ has the shape:

$$B = \begin{bmatrix} b_{11} \\ b_{21} \end{bmatrix}_{(j+i)xj}$$  \hspace{1cm} 3.2-10

The sub-matrices for matrix $B$ can be seen below:

$$b_{11} = \frac{1}{C_{dc}} [I]_{jxj} \hspace{1cm} b = [0]_{ixj}$$  \hspace{1cm} 3.2-11

The output matrix $C$ is an identity matrix while the output matrix $D$ is a zero matrix.

$$C = [I]_{(j+i)x(j+i)}$$
$$D = [0]_{(j+i)x(i)}$$  \hspace{1cm} 3.2-12

As mentioned, the transmission line has been implemented using the π-equivalent mono-polar model. The HVDC line can be extended based on the model to become a bipolar transmission system.

For the study, the model with a point-to-point topology, as in Figure 6, is extended as multi-terminal DC topologies, in Figure 7 and Figure 8.
For the multi-terminal topology, the three VSC stations are connected by HVDC cables. The two areas consist of classical AC systems such as a synchronous generator, modelled using single machine representation. The third area is an offshore wind power plant, modelled as a DC current injection to the AC node. For the primary frequency response study the wind power plant’s aid is not investigated. The strengthening of the AC systems’ frequency response is performed only with the help of the GSVSCs.
The MTDC has two connection possibilities. One is through a meshed connection and the other is through a radial connection. The calculations and details used for the model can be found in Appendix B.

For the meshed grid, the capacitance and inductance of the cables have been considered equal, although this can be changed in the model. The capacitance of the cables, denoted with $C_{dc}$, includes the capacitance of the VSC converter as well, denoted by $C_{VSC}$. This notation has been made for the simplification of the calculations.

The second possibility for building a three VSC station network is through a radial connection.

Again the inductance, resistance and capacitances of the cables have been considered equal for all the lines. The detailed differential equations for the state-space form and the calculations performed for the radial connection network can be found in Appendix B.

### 3.2.1. Newton-Raphson Method for DC Grid Power Flow

For systems such as the above, in Figure 6, Figure 7 and in Figure 8, in order to solve the DC power flow the Newton-Raphson method can be applied. [31] [32] The method is used to obtain the DC node voltages, the DC line currents and the power supplied to each node. The values are used for the initialization of the states the simulations.

The Newton-Raphson method is a mathematical technique that can be used to solve a system of nonlinear algebraic equations. Such a system can be written as [32]

$$f(x) = 0$$

### Figure 8 Radial connection of a VSC-HVDCD MTDC network with three terminals

![Diagram of Radial connection of a VSC-HVDCD MTDC network with three terminals](image-url)
where \( x \) is a \( n \)-vector of unknowns and \( f \) is a \( n \)-vector function of \( x \). Using an appropriate initial condition \( x^0 \), the Newton-Raphson method generates the following [32]:

\[
J(x^p)\Delta x^p = -f(x^p)
\]

\[
x^{p+1} = x^p + \Delta x^p
\]

where \( J(x^p) = \frac{\partial f(x)}{\partial x} \) is the Jacobian matrix with the elements

\[
J_{ij} = \frac{\partial f_i}{\partial x_j}
\]

The Newton-Raphson method will be now detailed for a multidimensional case. Thus, the \( n \)-dimensional function

\[
f(x) = 0
\]

can be written as

\[
f(x) = (f_1(x), f_2(x), \ldots, f_n(x))^T
\]

and

\[
x = (x_1, x_2, \ldots, x_n)^T
\]

The Newton-Raphson method follows several steps in solving the function in Equation 3.2.13. These steps are [32]

1. Set \( p = 0 \) and choose an appropriate initial condition \( x^0 \);
2. Compute \( f(x^p) \);
3. Test the convergence:
   - If \( |f_i(x^p)| \leq \epsilon \) for \( i = 1, 2, \ldots, n \) then \( x^p \) is the solution
   - \( \epsilon \) is the error that is accepted
   - Otherwise step 4 is required;
4. Compute the Jacobian matrix \( J(x^p) \)

   The general form of the Jacobian matrix is the following

\[
J = \frac{\partial f}{\partial x} = \\
\begin{pmatrix}
\frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \cdots & \frac{\partial f_1}{\partial x_n} \\
\frac{\partial f_2}{\partial x_1} & \frac{\partial f_2}{\partial x_2} & \cdots & \frac{\partial f_2}{\partial x_n} \\
\vdots & \vdots & \ddots & \vdots \\
\frac{\partial f_n}{\partial x_1} & \frac{\partial f_n}{\partial x_2} & \cdots & \frac{\partial f_n}{\partial x_n}
\end{pmatrix}
\]
5. Update the solution

\[
\Delta x^p = -J^{-1}(x^p)f(x^p)
\]

\[x^{p+1} = x^p + \Delta x^p\]

6. Update the iteration \(v + 1 \rightarrow v\) and go to step 2.

The Newton-Raphson method has been applied to obtain the DC power flow in both the point-to-point topology and the multi-terminal one. The input conditions of the method are the voltage of the slack node and the powers for all the other nodes.

### 3.3. VSC converter modelling

The modelling of a voltage source converter can be made in a detailed manner (by modelling the switching devices) or it can be done by a time-average VSC model. Each has its own advantages. The detailed model can help analyze the pulse-width-modulation, the topology, the harmonic components and accurate losses. Although this cannot be attained in a time-average approach, this method is sufficient to study the fundamental frequency, voltage and current components. In the time-averaged modelling there is no difference between a two-level and a multi-level VSC, considering the AC side. In this type of modelling, a VSC can be represented by a three-phase controllable AC voltage source on the AC side and as a DC current injection on the DC side. [4].

For the present thesis, the time-average modelling has been selected for the developing of the VSC. The relation between the AC and DC side of the time-averaged VSC is the conservation of power. The power on the AC side should be equal to what is injected in the DC side (lossless converter is assumed). This is also controlled by the modulation indices. The AC filter has been removed from the AC side of the converter, for the purpose of this study.

The picture below illustrates such a VSC model. The DC current injection can be calculated using the power balance between the AC and the DC sides. [33]

---

![VSC model diagram](image)

**Figure 9 VSC time averaged model**
The AC side of the converter generates voltage waveforms that are controllable in frequency, amplitude and phase angle. The power losses in the converter caused by switching and voltage drops across the switches and anti-parallel diodes are small compared to the power transferred through the converter. Therefore, it can be assumed that the active power at the common bus is equal to the power exchanged at the DC side of the converter.

\[ P_{ac} = P_{dc} = U_{dc}I_{dc} \]  

where \( P_{ac} \) [W] is the active power on the AC side of the converter, \( P_{dc} \) [W] is the power at the DC side of the converter and \( U_{dc} \) [V] and \( I_{dc} \) [A] are the DC voltage and DC current respectively, on the DC side of the converter.

At the DC side of the converter, a chopper is employed to prevent the occurrence of an overvoltage and jeopardizing the equipment. The purpose of the chopper is to dissipate the excess power. The more detailed presentation and use of the chopper can be seen in Chapter 3.6.

### 3.4. Control methods for VSC-HVDC

The VSC can have either an active AC grid connection or a passive AC grid connection. In active AC grid connection the frequency is determined from the AC system, thus the VSC needs to synchronize to the grid, while in a passive grid connection the VSC can set the frequency. Offshore VSCs are passive grid connections that also have an AC voltage control. In active connections, the VSC-HVDC has a synchronization mechanism that allows the injection of active and reactive power in the AC grid. In the VSC-HVDC grids, the converter stations are characterized by the rated power transfer capacity, the rated DC voltage level and its DC voltage response characteristic, which is given by the outer controller method. There are three types of methods used for the outer controller: the constant power control, the constant DC voltage control and the DC voltage droop control [4] [33].

The control modes of a VSC – HVDC system include the inner and the outer control modes. The inner controller ensures a fast response for the VSC while the outer controller regulates the active and reactive power and controls the DC voltage. [33] Both types of controllers for the VSC will be discussed in this chapter.

Figure 10 presents the VSC scheme with the outer and inner controllers. In this study, the AC side of the converter has been modelled with controllable voltage sources. These controllable voltage sources can be controlled in amplitude, phase-angle and frequency with the use of the signals from the inner controller of the VSC station. The dynamics of the pulse-width modulator and of the switching devices is not of interest in the present thesis and thus can be excluded, since the time frame of the simulations will be in the order of seconds. The detailed model of the inner controller is presented in Figure 13.

The DC side of the converter is modelled as a DC current source in parallel with the DC capacitor. The power losses in the converter, due to switching and voltage drops across the switches and diodes, are considered small with respect to the rated power of the converter and thus are not taken into consideration for the present thesis. [18] Therefore, the time-average
model of a VSC is used, where the conservation of power is maintained from the AC to the DC side.

As it can be seen from Figure 10, the $U_{abc}$ and $I_{abc}$ are measured at the common bus and transformer in the $dq0$ frame with the use of power invariant Park transformation. The magnitude of the $dq$ quantities is made equal to the peak phase value of the corresponding $abc$ quantities and the d-axis component of the common bus voltage is aligned in phase with phase $a$ of the common bus voltage.

The active and reactive powers obtained from the measurements at the common are computed based on the following equations:

$$ P = U_{c,a}i_a + U_{c,b}i_b + U_{c,c}i_c $$  \hspace{1cm} \text{(3.4-1)}

$$ Q = \frac{1}{\sqrt{3}}[(U_{c,b} - U_{c,c})i_a + (U_{c,c} - U_{c,a})i_b + (U_{c,a} - U_{c,b})i_c] $$  \hspace{1cm} \text{(3.4-2)}
where $P [W]$ and $Q [VAR]$ are the active and reactive power, respectively, exchanged at the common bus. $U_{c,a}[V]$, $U_{c,b}[V]$ and $U_{c,c}[V]$ are the phase voltages at the common bus and $i_a[A]$, $i_b[A]$ and $i_c[A]$ are the phase currents at the AC side of the converter.

The three-phase phase-lock loop tracks the frequency and the phase of the sinusoidal three-phase signal. Using the Park transformation, the three-phase signal is converted to the dq0 rotating frame using the angular speed of the internal oscillator. The quadrature axis of the signal is filtered through a mean block and the result is used in a PID controller, with an automatic gain control, that keeps the phase difference to zero using an oscillator. The PID output is filtered and converted to frequency, in Hz.

![Phase lock loop scheme](image)

**Figure 11 Phase-lock loop scheme**

3.4.1. **Inner Current Control Loop**

This control loop is also known as the active front end connection and is capable of determining the phase angle and the frequency with the use of a phase lock loop (PLL). For the active front end control, the approach used in the present thesis employs the synchronously rotating reference to observe the AC voltage and current quantities. This method of control is also called the d-q control of the active front end of the VSC. It has come from the electrical machines and drives study and it is used as a control approach for many VSC applications. This method considers all AC quantities balanced. [4]

For a steady state operation the active power exchange at the AC side with the power exchange at the DC side should be equal.

![Positive sequence RMS value equivalent model of a VSC station](image)

**Figure 12 Positive sequence RMS value equivalent model of a VSC station**
From the voltage difference between $U_c$ and $U_s$ and based on the conservation of power, the current injection in the DC network can be obtained.

Using the power invariant Park transformation the voltage can be written in the d-q reference frame as follows:

\[ U_{c,d} = U_{s,d} + \omega L i_q + L \frac{di_d}{dt} \]  
\[ U_{c,q} = U_{s,q} - \omega L i_d + L \frac{di_q}{dt} \]

The d-q reference frame is chosen such that the d-axis is aligned with the phasor of the voltage of phase-A of the grid at the point of common coupling. This under normal operation results in:

\[ U_{c,q} = 0 \]  
\[ U_{c,d} = U_c \]

For steady-state operation the active power at the AC side of the converter will be equal with the power exchange at the DC bus.

\[ P_c = U_{c,d} i_d \]

The reactive power becomes:

\[ Q_c = -U_{c,d} i_q \]

Figure 13 Inner controller of VSC-HVDC in d-q synchronous
The resistance of the phase reactor is considered small and for the scope of the present thesis it has not been considered. Therefore, the inner controller of the voltage source converter has been implemented as in Figure 13.

3.4.2. Active Power Control

The active power controller is part of the VSC outer control methods. If for a synchronously rotating frame the d-axis is aligned with the phase A of the AC voltage at the point of common coupling (PCC), then the q-axis component is zero. Therefore, the active power flow is controlled by the active current, which in the d-q control method is represented by \( i_d \). The output of the active power controller is the parameter \( i^{\text{ref}}_d \), which is used in the inner controller. [18]

The value of the reference current is obtained from the reference of the active power, from equation 3.4-8:

\[
i^{\text{ref}}_d = \frac{P^{\text{ref}}_c}{U_{c,d}}
\]

where \( i^{\text{ref}}_d \) [pu] is the d-axis component of the current flowing at the AC side of the converter, \( P^{\text{ref}}_c \) [pu] is the power that is passed through the converter, and \( U_{c,d} \) [pu] is the d-axis of the common bus voltage.

![Figure 14 PI controller for active power control](image)

The output of the PI controller will be used as the reference input for the d-axis of the inner current loop.

3.4.3. Reactive Power Control

The reactive power controller is part of the VSC outer control methods. It is controlled by the reactive current, which in the d-q control method is represented by \( i_q \). [4]

Analogously to the active power control method, the output of the reactive power controller, \( i^{\text{ref}}_q \), can be used in the inner controller. The value of the reference current for the q-axis is obtained from:

\[
i^{\text{ref}}_q = \frac{Q^{\text{ref}}_c}{U_{c,d}}
\]
where \(i_q^{\text{ref}}[\text{pu}]\) is the q-axis component of the current flowing through the AC side of the converter, \(Q_c^{\text{ref}}[\text{pu}]\) is the reactive power at the common bus, and \(U_{c,d}[\text{pu}]\) is the d-axis of the common bus voltage.

The output of the PI controller will be used as the reference input for the q-axis of the inner current loop.

![Diagram of PI controller for reactive power](image)

**Figure 15** PI controller for the reactive power

### 3.4.4. DC voltage regulator – Proportional Integral based

The integral controller for the DC bus voltage is part of the VSC outer control methods. The DC voltage can be controlled by the active current \(i_d\). The purpose of the integral controller of the DC bus voltage is to maintain the DC voltage at the reference value by regulating the power exchange at the common bus.

The output of the DC voltage controller is used in the d-axis inner controller of the VSC [18].

The active power exchange through the converter is:

\[
U_{dc}^{\text{ref}} I_{dc} = i_d^{\text{ref}} U_{c,d}
\]

The above equation can be rearranged in order to obtain the d-axis current component at the DC side of the converter:

\[
i_d^{\text{ref}} = \frac{U_{dc}^{\text{ref}}}{U_{c,d}} I_{dc}
\]

where \(U_{dc}^{\text{ref}}[\text{pu}]\) is the DC voltage across the DC capacitors, \(U_{c,d}[\text{pu}]\) is the d-axis of the common bus voltage and \(I_{dc}[\text{pu}]\) is the current through the DC link.

![Diagram of PI controller for DC voltage](image)

**Figure 16** PI controller for DC voltage regulator
3.4.5. DC Voltage regulator - Droop based

The DC voltage droop control employs a strategy that represents a droop characteristic. In this way, there is a linear relation between the DC voltage deviation and the d-axis component of the current through the converter. The variations in the d-axis component are related to the variations in the active power through the converter station. Therefore, with the DC voltage droop control, a linear relation between the DC voltage and the active power in the converter is created [21].

The diagram that presents the DC voltage controller that implements this strategy is shown in Figure 17.

![Figure 17 DC Voltage droop control](image)

The droop regulator controller will adjust the active power in order to maintain the DC voltage at normal operating values. This control method does not allow the controller to operate in a fixed power sharing way. The active power through the converter will change according to the DC voltage.

![Figure 18 Droop characteristic of the DC voltage droop controller](image)

3.4.6. AC Voltage Controller

The AC voltage controller is used to control the amplitude of the AC voltage at the common bus. It is attained by reactive power compensation, meaning that the controller dictates to the converter the amount of reactive power that is to be generated in order for the voltage at the common bus to match the reference value. [4]
3.4.7. Current limiter

The semiconductor switches and the diodes present in a VSC have limited ratings for the current that can flow through them. In order to avoid higher overcurrent than the voltage-source converter can tolerate, a current limitation strategy is applied.

The current limiter compares the reference values of the currents obtained from the VSC outer controllers with the maximum permitted value. If the values are above the allowed ones, then the output of the current limiter will be the maximum allowed values.

The magnitude of the reference value current obtained from the outer controllers is:

$$|i| = \sqrt{i_{d,ref}^2 + i_{q,ref}^2}$$

where $|i|$ is the magnitude of the current reference value $i_{d,ref}$, is the d-axis current reference value and $i_{q,ref}$ is the q-axis current reference value. All the three currents are expressed in [pu]. [18] [21]

For the present thesis, the $i_{d,ref}$ priority has been employed, which is presented in Figure 20, A. There are two other priority strategies, the second gives $i_{q,ref}$ priority in Figure 20, B, while the third performs an equal scaling between the two, in Figure 20, C.
3.4.8. Modulation index limiter

The converter operation should be in the linear region, $0 \leq m_a \leq 1$. In order to ensure such an operation a modulation index limiter is used. The scheme is presented Figure 21.

Figure 21 Modulation index limiter

where $m_a$ is the modulation index, $U_{c,base}$ is the base value of the converter voltage [V], $u_{d,ref}$ is the reference d-axis converter voltage [pu], $u_{q,ref}$ is the reference q-axis converter voltage [pu], $U_{dc,cap}$ is the voltage over the DC capacitors [V] and $U_{dc,base}$ is the base value of the direct voltage [V].

3.5. Equivalent Offshore Wind Park model plus offshore converter

The modelling of the offshore wind park is presented in Figure 22. The modelling of the wind park is done as a current injection, based on the power that is expected to be injected in the HVDC link. Since the voltage is assumed as known or is solved with the Newton-Raphson method, the current injection can also be obtained using equation 3.5-1.

In the present thesis, no contribution in the primary frequency response is considered from the wind power plant and therefore, the offshore wind power plant and the converter is equivalent to scheme presented in Figure 22.

Figure 22 Offshore wind plant modelling

$$I_1 = \frac{P_{owp}}{U_1} \quad 3.5-1$$
3.6. Chopper modelling

The purpose of the DC chopper is to dissipate power in emergency situations in order to limit the increase of the voltage. It is placed at the DC node of each converter station, in parallel with the DC capacitor.

![DC chopper diagram](Image)

**Figure 23** DC chopper

An emergency condition when the DC chopper is triggered can be a fault at the AC side of the converter. The active power, unable to flow in its normal path, will create a voltage increase. This occurs because the extra power will be stored by the DC capacitor. The role of the chopper is to dissipate the surplus of power and thus maintain the DC voltage at operational levels. [21]
4. Frequency response control schemes integrated in MTDC grids

The present chapter is organized as follows: First, an introduction to frequency response and system inertia is presented. Next, the synthetic inertia emulation theoretical concepts are discussed. Following, the control schemes implemented in the VSC controllers will be detailed. This consists in the frequency droop control method designed for the use in VSC-HVDC, the synthetic inertia method based on the frequency deviation, \( df/dt \), and finally the synthetic inertia emulation method used to improve the frequency response.

4.1. Frequency response

AC systems have a generation/demand balance that is maintained under normal operating conditions, assuming no storage is available. In case of trip of generator units, this balance is lost and the system frequency deviates at a rate determined by the total system inertia. A further endangering of the grid's stability will be caused if the renewable energy technologies will begin to replace the existing technologies. \[11\] \[12\]

The frequency will undergo deeper changes in case of disturbances as a consequence of integrating more power electronics in the future systems. The frequency response of the system will be negatively impacted and the security will be affected, with higher risks of black-outs. The future power systems’ capability of overcoming a disturbance is an important concern. \[16\] \[34\] In case of imbalances in the generation-demand of a synchronous system, due to increase or decrease in load or due to faults, the frequency will also vary. When a large generating unit is lost, the system frequency will decrease with an amount relative to the size of the loss. In order to prevent cascaded effects, black-outs, systems splitting in two or more parts or the collapse of entire systems, normal operational limits have been imposed on the magnitude of the frequency deviation. In case the frequency drops by more than 0.2 Hz \[9\], the generation plants connected are required to provide frequency response tasks. The frequency unbalance is corrected through controllers that improve the system frequency response. There are three time frames in which these controllers work: fast primary response or inertial response; governor response; automatic generation control (AGC); and tertiary response. \[9\]

Figure 24 presents the general frequency response for the three distinguished frames of time. In general, a frequency dead-band is used, in order to avoid any unnecessary frequency control or reaction from the systems. The frequency in an AC system does not have a perfectly stable value of 50 Hz, but is allowed to vary. The primary frequency response is dependent on the action of the generating resources to respond to the changes in frequency. This control is the first line of defense in overcoming a system disturbance. The secondary control is the Automatic Generation Control (AGC), which intervenes within tens of seconds after a disturbance and dominates the system response for several minutes after the disturbance has occurred. Tertiary control includes the actions taken by the system operator to get resources in place, such as reserve deployment, reserve restoration. \[35\]
In order to engage VSC-HVDC systems in the system frequency response various methods and controllers have been studied in this thesis. One method is the utilization of a frequency droop control loop in the outer controllers of the VSC [8], [10], [11]. Another method is the implementation of a synthetic inertia controller, either by using the frequency derivative $df/dt$ method, [9], [17], [36], or by using the energy stored in the DC capacitors to emulate an inertia response [37]. Lastly, to maintain a good frequency response, the stored kinetic energy of the wind turbines generators can be used. This can provide additional reserves for a time period in the order of 10s. [16] The latter method has not been the purpose of the present study; the wind power plant and the offshore converter have been implemented as a current injection to the MTDC grid.

The frequency droop controller and the synthetic inertia controllers are studied and tested in various scenarios and topologies, to ascertain their impact on the primary frequency response of the system. The sensitivities of the proposed controllers' parameters are tested as well, in order to compare, draw conclusions and minimize the influence on the frequency deviations in case of disturbance for AC systems with a large integration of VSC-HVDC.

### 4.2. Synchronous generator inertia

The frequency in an AC system is regulated within strict limits, by adjusting the electrical supply to meet the demand. If the balance is not reached the system frequency will change at a rate determined by the total system inertia, which is determined by the combined inertia of the spinning generation and load connected to the system.

The inertia constant of a generating unit or of a system ($H$) is used to define the energy stored in the rotating mass ($W_{\text{kinetic}}$). The definition of the inertia constant is the time, in seconds, that it would take to replace the stored energy when operating at the rated mechanical speed ($\omega_{sm}$) and the rated apparent power output ($S_{\text{machine}}$).
\[ H = \frac{W_{\text{Kinetic}}}{S_{\text{machine}}} = \frac{1}{2} \frac{J \omega_{sm}^2}{S_{\text{machine}}} \quad [s] \]  

where \( J \) is the total moment of inertia \([\text{kgm}^2]\), \( \omega_{sm} \) is the rated mechanical speed \([\text{rad/s}]\) and \( S_{\text{base}} \) is the base apparent power \([\text{MVA}]\). [9]

The rate of change of the frequency (ROCOF) after a disturbance can be determined using the following equation:

\[ \frac{df_1}{dt} \bigg|_{t=t_0} \approx \frac{f_i(t_0^+) - f_i(t_0^-)}{t_0^+ - t_0^-}, \]

where \( f_i(t_0^+) \) and \( f_i(t_0^-) \) are the frequency in Hz after and before the disturbance, which occurs at moment \( t_0 \), while \( t_0^+ \) and \( t_0^- \) represent the corresponding sampling times [9].

The frequency in an AC system is allowed to oscillate within the dead-band values. When the frequency exceeds the limits of the dead-band, the frequency control loops start participating in order to stabilize it.

The frequency NADIR is the minimum or the maximum value reached by the frequency after a disturbance. The difference between the rise or fall in the frequency is given by the type of disturbance that occurs.

### 4.3. Synthetic inertia emulation using electrostatic energy of the DC capacitors – Theoretical background

A method to support the AC system frequency response is the application of synthetic inertia emulation control loops. It uses the stored energy in the DC link capacitors’ in order to emulate inertia response [37]. This method is developed in a similar way to the inertia of a synchronous generator. The advantage is the frequency response provided using this method can be predicted. It does not imply using data with a lower level of accuracy as with using the kinetic energy stored in the wind turbines method [37]. This method does not employ the derivative of the frequency, \( df/dt \), thus it is less sensitive to noise amplification [37]. VSC systems use capacitors for the stability of the DC voltage as well as for filtering. The capacitor time constant can be expressed in the same manner as the machine inertia constant, in 4.2-1 [37].

\[ \tau = \frac{W_{\text{electro-static}}}{S_{\text{VSC}}} = \frac{1}{2} \frac{C_{dc}N U_{dc}^2}{S_{\text{VSC}}} \]

where \( C_{dc} \) is the capacitance of a single DC capacitor, \( N \) is the number of capacitors installed in the DC link, \( U_{dc} \) is the DC link voltage and \( S_{\text{VSC}} \), in Watts, is the VSC rated capability. The \( W_{\text{electro-static}} \) parameter is the electro-static energy stored in the capacitor [37].

The equation of a machine’s angular motion is presented in 4.3-2.
\[
\frac{2H}{f_0} \frac{df}{dt} = P_M - P_E = \Delta P_1 \ [\text{pu}]
\]

The above equation is used to determine the power available in the DC capacitors based on the power available in an electrical machine.

\[
\frac{NC_{dc}U_{dc}}{S_{VSC}} \frac{dU_{dc}}{dt} = P_{in} - P_{out} = \Delta P_2 \ [\text{pu}]
\]

where \(P_{in}\) and \(P_{out}\) are the power input and the power output, respectively, in the VSC. Both are expressed in pu. \(\Delta P_2\) represents the dynamic electro-static power stored or released across the DC capacitor or capacitors, expressed in [pu]. Based on equation 4.3-3, it is apparent that by changing the DC voltage the energy stored or discharged from the capacitors is also changed.

In order to assign an inertia constant for the HVDC system the above equations are equated. In order to cancel the terms \(\frac{df}{dt}\) and \(\frac{dU_{dc}}{dt}\) an integration is performed [37].

\[
\frac{2H_{VSC}}{f_0} \frac{df}{dt} = \frac{NC_{dc}U_{dc}}{S_{VSC}} \frac{dU_{dc}}{dt}
\]

\[
\frac{2H_{VSC}}{f_0} f = \frac{NC_{dc}U_{dc}^2}{2S_{VSC}} + K_1
\]

The integration constant is calculated for the specific values of the inertia constant of the VSC, \(H_{VSC}\).

\[
K_1 = \frac{2H_{VSC}f_0}{f_0} - \frac{NC_{dc}U_{dc0}^2}{2S_{VSC}} = 2H_{VSC} - \frac{NC_{dc}U_{dc0}^2}{2S_{VSC}}
\]

The integration constant is replace in equation 4.3-6 in order to obtain the inertia constant for the HVDC system.

\[
\frac{2H_{VSC}}{f_0} f = \frac{NC_{dc}U_{dc}^2}{2S_{VSC}} + 2H_{VSC} - \frac{NC_{dc}U_{dc0}^2}{2S_{VSC}}
\]

\[
\frac{2H_{VSC}}{f_0} f = \frac{NC_{dc}}{2S_{VSC}} (U_{dc}^2 - U_{dc0}^2)
\]
The final form of the HVDC inertia constant is given in equation 4.3-10.

\[
H_{VSC} = \frac{NC_{dc} U_{dc}^2 (U_{dc}^2 - U_{dc0}^2)}{2S_{VSC}} \left( \frac{U_{dc}^2}{U_{dc0}^2} - 1 \right)
\]

4.3-9

In order to simulate an inertia constant in the HVDC system, the DC voltage must vary with the frequency variation in the AC system. This variation however will not be linear [37].

The objective of the emulated inertia control is to obtain incremental energy similar to that provided by a synchronous generator with real inertia. A dead-band is also employed in order to stop the controller from reacting until the frequency deviation reaches a certain threshold, which limits the response only to large disturbances [9] [16].

4.4. Controller schemes integrated in MTDC grids for frequency control

4.4.1. Frequency droop control

The frequency response is measured in the increment in MW of the power in the AC system with response to the decrement in frequency of 1 Hz. Disturbances in either the AC or the DC systems lead to deviations of the AC frequency.

Since the power injection of a VSC can be controlled, in a similar manner to that of a synchronous generator (from the governor actions), a frequency droop control method can also be employed in the VSC to provide frequency response to the AC system. A frequency droop controller will provide additional power transfer from the DC link to the AC system, which will improve the frequency response. This additional power will be withdrawn from the DC side of the converter, altering the power flows and the DC voltage levels. When no frequency droop control is employed, there is no change in the power transfer in the DC grid [4] [8] [13].

After a contingency in the AC system, the frequency changes because of the governor’s action. A change in the real voltage reference for the converter station will result in a change of the power distribution between them. In order to change the power sharing between the converter stations, they have been fitted with an additional frequency droop control. Such a frequency droop controller can be seen in Figure 25.
The frequency change in the AC system will change the reference value of the $d$-axis current of the controller and therefore will change the DC voltage in the HVDC link. This will in turn change the injected power in that particular node. The method can be used in any VSC grid side station.

The gain $k_{p,f}$ is selected such that for a frequency change of 1Hz, a power change of 25MW occurs. This gain is can be varied and its sensitivity on the frequency response will be investigated. A dead-band for frequency deviations between 49.9Hz and 50.1 Hz has also been used. The results are presented in Chapter 6.

4.4.2. Synthetic inertia using the frequency derivative (washout block)

There are methods of using the VSC converters to generate a synthetic inertial response in order to help the frequency response of the AC systems. For the purpose of the present work, the synthetic inertia using the frequency derivative, $df/dt$, will be first investigated. This method measures the frequency at the grid connection point and adjusts the active current reference based on the derivative of frequency deviation. This method will be compared with the alternative approach that employs additional control loop which utilizes the PLL measurements to change DC voltage set-points. Both methods can use the energy stored in the DC capacitors to improve the frequency deviations. However, in contrast to the method which uses the $df/dt$, the second is more analytical and can predefine the contribution of the converter. The advantage of both methods proposed is that they can be used in any grid-side VSC station, and allow the MTDC to contribute with an inertial response during disturbances.

The idea behind the synthetic inertia control using the frequency derivative is to use the deviation in the grid frequency to modulate the active power in the converters. The active power is changed
by changing the reference value of the d-axis current in the outer controller of the converter station. Such a controller is presented in Figure 26 [11] [12] [17].

The frequency deviation from the nominal value is computed by subtracting from the reference value, 50 Hz, the measured frequency value. A dead-band is also employed so that the frequency’s normal operating deviations are not considered. A washout filter has been used instead of a derivative, which is mathematically equivalent [9] [36].

Figure 26 Synthetic inertia with frequency derivative control scheme

The synthetic inertia can be used in addition to the frequency droop control, for a better managing of the frequency deviation and a more efficient strengthening of the AC frequency response. In case both frequency controls are used they will be subtracted from the reference value of the d-axis current used in the inner controller.

4.4.3. Control method for synthetic inertia emulation – an advanced approach

The present subchapter will present the application of the method described above, in order to obtain the desired frequency response and strengthen the AC system using the capacitors stored energy to simulate inertia and change the DC link voltage in order to exchange primary frequency reserves.

Equation 4.3-5 is written in another form, based on the DC voltage.

\[
U_{dc}^2 = \sqrt{\frac{4H_{VSC}S_{VSC}}{NCf_0}} f - K_2 \quad 4.4-1
\]
and $K_2$ is expressed as follows:

$$K_2 = \frac{4H_{VSC}S_{VSC}}{NC} - U_{dc}^2$$  \hspace{1cm} 4.4-2$$

Based on the above equation the controller for the VSC-HVDC with the inertia emulator is presented in Figure 27. [37]
5. Model validation

The present chapter shows the results obtained for the power flow, for different topologies, computed with the use of the Newton-Raphson method.

Tests such as AC fault and step up and down in the wind power supplied to the DC link will be performed for the point-to-point and the multi-terminal HVDC topologies. Sensitivity analysis on the proportional gain as well as the integral gain of the DC voltage regulator droop based method will be performed.

5.1. Results for the Power Flow using the Newton-Raphson method

Using the Newton-Raphson method and the state-space model implemented in Simulink Matlab, three topologies have been tested to obtain the branch currents, the node voltages and the powers at each node for the multi-terminal DC grids.

The first topology, the three terminals meshed configuration, is also presented in Figure 6. In order for the Newton-Raphson technique to be applied, various parameters need to be initialized. The data introduced for the three topologies tested are presented in Table 1.

Table 1 Data used for the three topology tests

<table>
<thead>
<tr>
<th>Data introduced</th>
<th>Topology 1</th>
<th>Topology 2</th>
<th>Topology 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of lines</td>
<td>3</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Number of nodes</td>
<td>3</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td>Line Lengths</td>
<td>300 km (for all lines)</td>
<td>300 km (for all lines)</td>
<td>300 km (for all lines)</td>
</tr>
<tr>
<td>V (slack node)</td>
<td>320 kV</td>
<td>320 kV</td>
<td>320 kV</td>
</tr>
<tr>
<td>T1 (injected power)</td>
<td>400 MW</td>
<td>-400 MW</td>
<td>400 MW</td>
</tr>
<tr>
<td>T2 (injected power)</td>
<td>200 MW</td>
<td>200 MW</td>
<td>200 MW</td>
</tr>
<tr>
<td>T3 (injected power)</td>
<td>-</td>
<td>-</td>
<td>-600 MW</td>
</tr>
<tr>
<td>Assumed initial V1</td>
<td>320 kV</td>
<td>320 kV</td>
<td>330 kV</td>
</tr>
<tr>
<td>Assumed initial V2</td>
<td>320 kV</td>
<td>320 kV</td>
<td>330 kV</td>
</tr>
<tr>
<td>Assumed initial V3</td>
<td>-</td>
<td>-</td>
<td>330 kV</td>
</tr>
<tr>
<td>Assumed initial P</td>
<td>-600 MW</td>
<td>200 MW</td>
<td>0 MW</td>
</tr>
<tr>
<td>(slack node)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Incidence matrix</td>
<td>$I_M = \begin{bmatrix} 1 &amp; -1 &amp; 0 \ 1 &amp; 0 &amp; -1 \ 0 &amp; 1 &amp; -1 \end{bmatrix}$</td>
<td>$I_M = \begin{bmatrix} -1 &amp; 1 &amp; 0 \ -1 &amp; 0 &amp; 1 \end{bmatrix}$</td>
<td>$I_M = \begin{bmatrix} 1 &amp; 0 &amp; 0 &amp; -1 \ 0 &amp; 1 &amp; 0 &amp; -1 \ 0 &amp; 0 &amp; -1 &amp; 1 \end{bmatrix}$</td>
</tr>
<tr>
<td>Cable R per km</td>
<td>0.03Ω</td>
<td>0.03Ω</td>
<td>0.03Ω</td>
</tr>
<tr>
<td>Cable L per km</td>
<td>0.0002H</td>
<td>0.0002H</td>
<td>0.0002H</td>
</tr>
<tr>
<td>Cable C per km</td>
<td>220nF</td>
<td>220nF</td>
<td>220nF</td>
</tr>
<tr>
<td>VSC capacitance</td>
<td>250µF</td>
<td>250µF</td>
<td>250µF</td>
</tr>
</tbody>
</table>

Based on the above introduced data and using the Newton-Raphson method, the results for power flow obtained for the three terminals meshed topology can be seen below:
Table 2 Results obtained with Newton-Raphson for Topology 1

<table>
<thead>
<tr>
<th>Results obtained</th>
<th>Branch currents</th>
<th>Node voltages</th>
<th>Node powers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line 1</td>
<td>201.4 A</td>
<td>Node 1 329.13 kV</td>
<td>Node 1 400 MW</td>
</tr>
<tr>
<td>Line 2</td>
<td>1013.9 A</td>
<td>Node 2 327.31 kV</td>
<td>Node 2 200 MW</td>
</tr>
<tr>
<td>Line 3</td>
<td>812.5 A</td>
<td>Node 3 320 kV</td>
<td>Node 3 -584.4 MW</td>
</tr>
</tbody>
</table>

The second configuration tested is presented below, in Figure 28.

![Figure 28](image)

Figure 28 Topology 2 tested with Newton-Raphson Method

The results for topology 2 using the Newton-Raphson method are presented below, in Table 3.

Table 3 Results obtained with Newton-Raphson for topology 2

<table>
<thead>
<tr>
<th>Results obtained</th>
<th>Branch currents</th>
<th>Node voltages</th>
<th>Node powers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line 1</td>
<td>625.39 A</td>
<td>Node 1 314.17 kV</td>
<td>Node 1 -400 MW</td>
</tr>
<tr>
<td>Line 2</td>
<td>647.8 A</td>
<td>Node 2 319.8 kV</td>
<td>Node 2 200 MW</td>
</tr>
<tr>
<td>Line 3</td>
<td>614.4 A</td>
<td>Node 3 320 kV</td>
<td>Node 3 207.3 MW</td>
</tr>
</tbody>
</table>

The last topology for which the Newton-Raphson method is tested is the three terminals radial configuration, presented in Figure 29 and the results are shown in Table 4.

Table 4 Results obtained with Newton-Raphson for Topology 3

<table>
<thead>
<tr>
<th>Results obtained</th>
<th>Branch currents</th>
<th>Node voltages</th>
<th>Node powers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line 1</td>
<td>1208.9 A</td>
<td>Node 1 330.88 kV</td>
<td>Node 1 400 MW</td>
</tr>
<tr>
<td>Line 2</td>
<td>614.4 A</td>
<td>Node 2 325.53 kV</td>
<td>Node 2 200 MW</td>
</tr>
<tr>
<td>Line 3</td>
<td>1985.9 A</td>
<td>Node 3 302.13 kV</td>
<td>Node 3 -600 MW</td>
</tr>
<tr>
<td>Node 4</td>
<td>320 kV</td>
<td>Node 4 3 kW</td>
<td></td>
</tr>
</tbody>
</table>
The tests were performed in order to obtain the Newton-Raphson results and investigate if the method can be applied for multi-terminal configurations as well as point-to-point configurations in either a meshed or a radial connection.

5.2. Model validation point-to-point topology

The point-to-point topology simulated in this paragraph is presented in Figure 30. Various tests have been conducted in order to ascertain the validity of the model. The tests performed are a step up and down in the current in-feed from the wind park to the MTDC network and a fault in the AC system. Besides the mentioned tests, some sensitivity of the voltage droop proportional parameter, \( k_p \), and the integral parameter, \( k_i \), have been tested as well.

For the model validation the AC system has been implemented as an infinite grid. The DC voltage regulator of the VSC uses the proportional-integral method. For these simulations, the
initial power injection of the wind park is considered to be 540 MW and the DC line has a rating of 230kV. In the first set of simulations a step has been introduced at the current \( t_1 = 6 \text{s} \) and the step down in the current occurs at \( t_2 = 18 \text{s} \). The amplitude of the step is of 0.2 [pu]. The results corresponding to this particular test are presented in Figure 31 and Figure 32. For this test the proportional gain of the outer DC voltage control of the VSC was set to \( k_p = 4 \) while the integral gain has been set to \( k_i = 20 \).

Figure 31 Results for step up and step down in the current injected at the wind park converter

Figure 31 starts by presenting the step up and down of the current in-feed by the wind power plant into the DC link. Below, the DC line current is measured through the DC link and at node 2, where the VSC will convert the power received for it to be fed into the AC system. The current measured at the GSVSC is reversed in sign from the one in the DC link since the AC area is receiving the power, and the converter acts as an inverter. The DC voltage at node 1 will be higher than the DC voltage at node 2 since the power flow takes place from node 1 to node 2 in the point-to-point topology. The reference value for the DC voltage at node 2 is considered known as 230 kV and the reference value of the DC at node 1 is computed with the Newton-Raphson method. However, the power injected in node one is also known as 540 MW, but the
power received at node 2 is again obtained with the Newton-Raphson method. The power received by the AC area will be lower than the wind plant delivers because of the transmission losses. Both voltages exhibit the same type of behavior when the current injection changes. The voltages have a fast rise and decrease during the step-up in the current injection and a fast decrease and rise during the step-down of the current injection. The VSC voltage droop controller of area 2 tries to maintain the voltage reference, and returns to the value of 230kV. However, there will be a voltage difference at node 1 after the step up until the step down occurs. This due to the increase of power delivered to the DC link from the wind power plant.

The active power injected from the DC link in the AC grid follows the behavior of the wind current injection, and increases with the step-up then decreases with the step-down. The power in the AC grid is lower than the power injected by the wind parks due to transmission losses in the DC cable. As expected, the reactive power shows no change, since the change has been only in real power. Therefore, only the d-axis current at the GSVSC is changed and not the q-axis one.

Figure 32 Results for step up and step down in the current injected at the wind park converter

Figure 32 shows the instantaneous values of the voltages and currents in the AC area. For a clear view of their behavior, the time interval shown is shorter than the simulation time and is taken
with 0.1s before and after either step occurs. The voltage in the AC system is maintained constant throughout the change in power injection; however, the instantaneous AC currents show an increase in amplitude.

The last plotting in Figure 32, for the step-up/down test, are the currents obtained from the PLL and the current references from the VSC outer controllers. The PLL is used to change the measured currents and voltages at the AC side in the d-q framework. Again it can be seen that the values of the AC currents changes in the same manner with the step that is introduced in the DC current injection.

The second test performed in order to validate the point-to-point model, is introducing a fault in the AC system. The results for this simulation are presented in Figure 33 and Figure 34. The fault is introduced in the AC system at $t_1 = 6s$ and is cleared at $t_2 = 6.1s$. For the fault test the proportional gain of the outer DC voltage control of the VSC was set to $k_p = 4$ while the integral gain has been set to $k_i = 20$.

![Figure 33 Results for a 0.1s fault at the AC grid](image)

**Figure 33** presents the current through the DC link, the current measured at node 2, received by the GSVSC, the voltages at the two nodes of the point-to-point topology and the active and
reactive power in the AC grid. Each graph has a zoomed-in plot to show the relevant behavior at the moment of the fault.

During the AC fault the voltage in the DC link increases while the power transferred to the AC side is blocked. The power measured at the AC side reaches values of zero. The behavior can be seen in Figure 33. Since no power can be injected in the AC network, the chopper at the GSVSC is activated and begins to dissipate the excess amount of power across the capacitors. The chopper has been used to ensure the system is protected against such faults. This behavior can be seen in Figure 34, where the instantaneous values of the currents and voltages in the AC system are also presented. During the fault the instantaneous voltages become zero, while the current in the AC side increases. The limit to the magnitude of the currents during the fault has been set to 1 in the current limiter; therefore the currents do not exceed this value.

![Figure 34 Results for a 0.1s fault at the AC grid](image)

The validation of the model is followed by sensitivity tests performed for the proportional gain and the integral gain of the DC voltage outer controller of the GSVSC. The results obtained for the integral controller are presented in Figure 35. Due to the similarities between the behaviors of the gains, the simulation results for the proportional gain sensitivity can be found in Appendix D.

For both proportional and integral gains, the values used are 5, 10 and 20. As it can be seen from Figure 35, the value of the integral gain influences the voltage recovery time. The sensitivity test
has been performed in case of a step-up/down in the current injected at node 1 of the DC link. For the tests below the value of the integral gain is changed while the proportional gain is maintained at $k_p = 4$.

With a value of $k_i = 5$, the DC voltage does not recover at the same value as before the change in the current. This can be more clearly observed in the last plots, the graph of the active power being supplied to the AC system. The higher the integral gain the closer the power supplied to the AC grid is to the correct value.

![Graphs showing the effect of integral gain on DC voltage and power](image)

**Figure 35 Results for sensitivity of the PI DC Voltage Regulator parameter, $K_i$**

For the proportional gain, that can be seen in Appendix D, the sensitivity test shows the same type of results. Using a higher value for the gain will lead to the faster recovery of the DC voltage to the reference value after the step occurs for the current injection.

### 5.3. Model validation MTDC topology

For the multi-terminal DC grid in a meshed topology, the same tests as for the point-to-point configuration have been used in order to test the validity of the system. The GSVSC of AC area 2 has been set to DC voltage droop control, while the GSVSC of AC area 3 has been set to active
power control. This is an important feature to consider since the behavior of the two converters is different compared one to the other. The proportional and integral gains have been set to \( k_p = 4 \) and \( k_i = 20 \) for the outer controllers involved in both GSVSCs. The sensitivity of the proportional gain and of the integral gain has been tested as well.

The meshed topology that is used for the multi-terminal model validation is presented in Figure 36. The rating of the DC voltage is 230 kV and the converter power is 900 MW. From the wind park, 540 MW are being injected in the multi-terminal HVDC. For the simplification of the model all cable resistances, capacitances and inductances have been considered equal. The length of the cables has also been considered equal to 300 km for all. The AC systems have been modelled as infinite grid systems.

The first test performed is the step-up/down in the current in-feed from the wind park, at node 1. The results for the simulation can be seen in Figure 37. When the current injection at node one is increased, the expected result is that the current in the DC line 1 (from the wind park to AC area 2) and DC line 2 (from the wind park to AC area 3) will also increase. The current in line 3, from area 2 to area 3 decreases. This can be seen on the left side of Figure 37. The right side of the graph, presents the DC voltages at the three nodes. The behavior for the three node voltages is similar to the behavior in the point-to-point topology.

The results for the powers in the AC areas for this test can be found in Appendix D, since the behavior is similar to the point-to-point topology. The only difference is that the power from the multi-terminal DC to AC area 3 is not changed by the step condition since the converter has been set in active power control. This is reinforced by the DC voltage behavior as well. Since the power in-feed from node 1 changes, the DC voltage of node 1 changes as well. At node 2, the voltage returns to the 230kV after the step, either up or down, leading to more power being
supplied to the respective AC area. However, since the GSVSC of area 3 is set to active power control, the voltage will not return to the 230kV after the step-up, in order to maintain the same power in-feed to the AC area.

In Appendix D, the instantaneous values for the currents and voltages can be found. Since the GSVSC of area 2 is set to DC voltage droop control, the instantaneous currents will follow the DC current change, while the AC voltages will maintain their amplitude. For AC area 3, since the GSVSC is set to active power control, there will be no change in the power input in the area, and therefore both the instantaneous voltages and currents will maintain the values they had before the step occurred.

The values of the d-axis and q-axis reference currents from both the PLL and the outer controllers of the GSVSCs, for the step-up/down validation test can also be found in Appendix D. The behavior is similar to the power transferred in the two AC areas. The converter control mode dictates if the d-axis reference value will be changed. For the DC voltage droop control the d-axis reference value is changed while for the active power control mode the d-axis current reference remains constant. As expected, the q-axis value will remain constant and equal to zero for the
extent of the simulation since no change in the reactive power has been made. The in-feed from the wind power plant is in active power.

The second test performed in order to validate the multi-terminal DC model, is the AC fault test. First a fault in the AC area 2 is introduced at $t_1 = 6s$ and cleared at $t_2 = 6.1s$, followed by a fault in AC area 3 at $t_3 = 18s$ which is cleared at $t_4 = 18.1s$. The results for the instantaneous currents and voltages for the two AC areas during the fault are presented in Figure 38. The graphs have been plotted for the timeframe relevant for the fault and its clearing. The DC node voltages can be seen in Figure 39. The rest of the simulation results for the AC fault test can be found in Appendix D. These include DC line currents, power injection in the AC areas and d-axis and q-axis currents.

As it has been previously mentioned, the GSVSC of AC area 3 is set to active power control mode while the GSVSC of AC area 2 is set to DC voltage droop control. Therefore, when the fault occurs in AC area 2 at $t_1 = 6s$ it will not propagate in any way in the other AC area. This can be seen in the left side of Figure 38. The voltage in AC area 2 will drop to a zero value while the current increases. The value of the current is limited at 1[pu] in the current limiter employed in the outer controller, therefore the AC instantaneous currents will not reach values higher than
1[pu]. The AC area 3 will not react to this fault since the GSVSC 3 has been set to active power control.

On the right side of the graphs set, a fault is shown for the AC area 3 at moment $t_3 = 18s$. For the duration of the fault, the instantaneous voltages in the AC area drop to zero while the current is increased. The value of the instantaneous currents is again limited to 1[pu] by the current limiter used in the VSC. However, due to the DC voltage droop control method employed in the GSVSC of area 2, the fault will propagate to this area as well. The instantaneous voltages remain the same; however the amplitude of the currents is increased. [38]

The DC node voltages are presented in Figure 39. As it can be seen the two faults in the AC areas change the DC node voltages; however the voltage is restored to its initial value after the fault is cleared.

![Figure 39 DC voltages for multi-terminal validation test – fault in AC areas](image)

As in the point-to-point topology validation test, the sensitivities of the proportional and integral gains employed in the outer controller of the VSC have been tested. Since for the previous test the integral gain has been discussed, the proportional gain will be detailed here. The DC node voltages graph obtained for various proportional gains of the DC voltage controller is presented in Figure 40. The rest of the results for the proportional gain test (power injection in AC areas, DC
line currents) as well as the sensitivity test results for the integral gain parameter can be found in Appendix D.

Figure 40 Results for sensitivity of the Kp parameter of the DC Voltage controller

The DC node voltages exhibit the same type of behavior in the multi-terminal DC as in the point-to-point topology. For a step-up/down in the current injected from the wind park, the voltages will deviate from the initial value. The higher the proportional gain, the lower the deviation from the reference and initial value will be. This is easily observed in Figure 40 where the proportional gain $k_p$ takes the values of 5, 10 and 20. For the integral gain a value of $k_i = 20$ has been used in the simulations.

5.4. Frequency response for a conventional generator

The last test for the model validation is the AC system frequency response. The sensitivity of the governor and system inertia parameters is investigated in case of a load increase. The tests have been performed for a 900 MW synchronous generator with a governor system and excitation system. The AC system is modelled as a single machine system. The configuration tested is for an isolated generator, without any connection to the VSC-HVDC system in order to understand the
behavior in normal operating conditions and the frequency response. The entire list of parameters for the system used can be found in Appendix A.

A step in load of 30 MW has been considered at the moment $t = 2s$. The load has been chosen such that for standard parameters, the frequency deviation would not be severe.

Figure 41 Isolated AC system with step in load

Figure 41 presents the scheme of the AC system used for testing the primary frequency response. The first set of tests was performed for the synchronous generator’s inertia constant, $H[s]$. The results are presented in Figure 42. In case of the increase in load, by connecting the secondary load to the systems, the system frequency deviation from the nominal value is larger if the machine inertia constant is lower. Using a higher value for the inertia means that the synchronous generator has more kinetic energy stored and the frequency will not drop as much.

The mechanical power and the field voltage of the synchronous machine have been presented as well in Figure 42. The two parameters follow a similar behavior as the frequency of the AC system.

Based on the results obtained, for further frequency response tests for the system, the inertia constant has been chosen as $H = 6.5[s]$. This value for the inertia constant can be found in [39]. The inertia constant $H = 6.5[s]$ has been used in the testing of the frequency controllers.
The second sensitivity test is that of the permanent droop of the speed governor, $R_p[pu]$. The results are presented in Figure 43. The value of the permanent droop is varied between 0.025 [pu] and 0.065 [pu]. As it can be seen in the results, the variation of this parameter does not influence the frequency response of the system with the same degree as the inertia constant of the machine does. The frequency NADIR is less improved by varying the permanent droop of the speed governor than by changing the inertia constant of the machine. However, for lower values of the permanent droop, an improvement in the frequency recovery is noticed.

After the recovery of the frequency is performed, the frequency does not return to the nominal value before the disturbance. This is usually a safeguard method so that the secondary frequency response may intervene and reallocate new resources. The difference between the initial frequency state and the frequency value after the disturbance is called a steady-state error and it is used in the secondary control.
Based on the results from the inertia machine constant and the governor permanent droop, the models of the machine in the future frequency test have the parameters set as $H = 6.5\,[s]$ and $R_p = 0.045\,[pu]$. 

Figure 43 Generator’s behavior for a load increase of 30MW and Permanent Droop ($R_p$) change
6. Frequency response with control added to the VSC-HVDC

With the integration of more wind power energy as well as other renewable energy generation systems and the implementing the transnational European HVDC network the concern regarding the future power systems is that they will be susceptible to larger frequency deviations in case of disturbances (i.e. trip of generation unit), which may lead to loss of generating units, separation of AC systems in more parts or large scale black-outs.

The frequency controllers that can be implemented at VSC-HVDC systems have been presented in Chapter 4.4. The meshed multi-terminal VSC-HVDC network used in the simulations to test the various frequency control methods is presented below in Figure 44. The power flow in the HVDC network has been computed with the Newton-Raphson method.

A meshed multi-terminal HVDC grid connects two AC areas with a wind park. The converters are rated at 900 MW, the generators have a rating of 900 MVA and the simulations start with a loading of 50% on each generator. The power injected in the HVDC grid and the powers received by the AC systems are shown in Figure 44. A step in load of 30 MW is implemented in the AC system of area 3. The values of the permanent droop used in the governors for the AC generators are set to $R_p = 0.045 \,[\text{pu}]$ and the generators’ inertia is $H = 6.5 \text{s}$. The entire list of the parameters used for the AC systems are presented in Appendix A. For the simulations, both GSVSCs use the DC voltage regulator – droop based method.
The AC systems frequency response for the step in load in area 3 without any intervention from the VSC-HVDC is presented in Figure 45. The full extent of results for the generators is similar to that in the model validation and can be found in Appendix D.

Since the GSVSCs are not involved in supporting the AC systems, the frequency disturbance is corrected only by area 3, which provides primary frequency response through the synchronous generator and the governing system. Therefore, no changes in the currents and voltages of the MTDC are made. The frequency in area 2 is maintained constant throughout the disturbance, since the AC systems are decoupled and the disturbance does not propagate through the MTDC network without the use of additional control methods.

The NADIR of the frequency for AC area 3, without any control from the VSC-HVDC system reaches a value of 49.18 Hz. This value will be used to compare the frequency controllers, to see the support they are capable of providing and if the frequency response can be strengthened with addition of the frequency control methods. The frequency in area 2 remains at a constant 50 Hz value and it will be compared to the NADIR obtained in the simulations for the frequency controllers implemented.
6.1. Frequency droop control added to the VSC-HVDC

The frequency droop control method employed for the simulations is presented in Figure 25. The tests were conducted for two cases: the situation in which a frequency droop controller is added to the converter of AC area 3, where the load change occurs, and the situation where both GSVSC are equipped with the controller. Sensitivities of the gain used in the frequency droop control have also been tested, as well as the influence of the DC voltage proportional gain. Both converters use the DC voltage regulator - droop based method.

6.1.1. Frequency droop control added to the GSVSC 3

For the present test, the converter of the area 3, where the load change occurs, has been fitted with the frequency droop controller. The gain value for the frequency droop controller has been set to $k_p = 3$. The results for the simulation can be seen in Figure 46, Figure 47 and Figure 48. The load increase in area 3 is of 30 MW. The load is purely active and therefore, there will be no change in the reactive power.

Figure 46 Power injections in the AC areas and current reference for GSVSC 3 using frequency droop control
In Figure 46 it can be seen at the moment $t = 2s$ a disturbance occurs in AC area 3. At this moment, minor oscillations in the d-axis current of the outer controller of the converter and in the power of area 3 can be observed. There is no change in the power and d-axis current reference for area 2 at $t = 2s$.

The frequency droop controller, however, does not participate immediately, since it has been fitted with a dead-band to avoid normal operating oscillations of the frequency. The power injected in node 3 starts increasing when the frequency in the area drops below 49.9 Hz. The frequency measured at the PLL is subtracted from the nominal value and the result is used to increase the d-axis current reference in the outer controller of the GSVSC, and therefore more power will be injected in the area. Due to the dead-band and the power injected, oscillations occur in the power injected in area 3, the DC line currents and the DC voltages. The reason for the oscillations is the increase in power in area 3 and thus the improvement of the frequency deviation. The frequency reaches values within the dead-band and the controller stops participating. However, the frequency continues to decrease, and therefore the controller becomes active again. This occurs for a short timeframe, while the frequency will reaches values in and out of the dead-band. The nominal rating of the AC system compared to that of the VSC has an important role in the occurrence of the oscillations.

Figure 47 DC currents and voltages in the MTDC for GSVSC 3 with frequency droop control
The frequency droop controller changes the power supplied to AC area 3 by measuring the frequency deviation and changing the DC node voltage for the area under disturbance. The change in the DC node voltages will lead to a change in the DC line currents through the MTDC grid. This behavior of the converters can be seen in Figure 47. With the change in voltage and in the currents for the VSC of area 2, the power injected in the AC system 2 will be reduced. Due to the decrease of power injected in area 2, but maintain of the load, the frequency will start to decrease as well. The voltage after the contingency comes close to the initial value but does not reach it since, the frequency does not return to the 50 Hz value. The frequency remains at a slightly lower operating point in order for the secondary frequency control to participate in the frequency support. Since the frequency does not recover to the 50 Hz value, this difference in frequency will change the reference value of the d-axis current. Therefore, the voltages will not return to the reference values after the disturbance.

Figure 48 Frequency response in AC areas for GSVSC 3 with frequency droop control

The converter used for area 2 employs no frequency droop control method and thus the frequency deviations will not be corrected in any way by the VSC-HVDC network. In area 2 only the synchronous generator and the governing system support the system’s frequency response. This is an important feature to be considered, since without any type of limitation, the frequency deviations in area 3 will be corrected at the expense of area 2. Therefore, frequency deviations
may be stronger in this area since there are no added control methods, and it may lead to severe frequency excursions and further disturbances in a real-life scenario.

As it can be observed, the frequency response for AC area 3 has been improved compared to the no frequency control case. Although the frequency has been decreased in the second AC area, no severe consequences could have occurred from this particular case since the load change implemented is low compared to the system rating. The frequency in area 2 has been restored by the synchronous generator and governing system. The frequency in area 3 has a new NADIR value of 49.44 Hz while the frequency NADIR in area 2 is 49.68 Hz.

Figure 49 presents a comparison between the cases when the frequency droop controller is equipped with a dead-band and when it is not. In order to perform this test frequency normal operating deviations need to be ignored. Therefore, the frequency droop controller has been allowed to detect frequency changes only after the load in area 3 is increased.

Figure 49 Comparison with and without dead-band for power supplied to AC areas and d-axis current references

Based on the simulations conducted, without the dead-band no oscillations are observed in the powers supplied to the two AC areas and in the d-axis current references. The increase or decrease in power and current references has a more linear shape.
The use of a dead-band leads to the occurrence of oscillations. However, the nominal power rating of the AC systems compared to the VSC rating has consequences on the oscillations occurring as well. For large AC systems, in the order of GVA, the frequency deviation would be less improved by the VSC, when the frequency first reaches values below 49.9 Hz. Therefore, the frequency does not reach values within the dead-band again, reducing the oscillations or eliminating them. The corrections that could be performed with the use of a small VSC-HVDC system to a much larger AC system would be less significant.

Using a dead-band is necessary in a real system because the frequency does not have a value fixed at 50 Hz at all times and low oscillations take place in normal operating conditions. The entire list of results for the frequency droop control without the dead-band can be found in Appendix E.

6.1.2. Frequency droop control added to all converters

The present test is performed to observe the behavior when both grid-side converters use the frequency droop control method. The results are presented in Figure 50, Figure 52, Figure 53 and Appendix E. The same AC systems and VSC-HVDC network as in the previous scenario have been used.

As mentioned, if the GSVSC of the second AC area is not fitted with a limitation on the power reserve change or a frequency droop controller, the frequency may have larger deviations than the permitted values and cascade effects may occur. Without the added support, the frequency response in area 3 will be strengthened while the frequency deviations in area 2 will be greater.

As in the previous case, the reactive power does not change during the simulation. The load increase is in active power only, at the moment $t = 2s$ of the simulation. At this moment, minor oscillations can be observed in the power supplied to area 3 and in the d-axis reference of area 3, in Figure 50. After the frequency in this area reaches a value below 49.9 Hz, the power supplied to it is increased, in order to help restore the frequency. This is achieved by the frequency droop control added in the GSVSC of area 3, by changing the d-axis current reference of the outer controller. The power injection therefore continues to increase in AC area 3. The difference in the present test is that the VSC of area 2 has also been fitted with the frequency droop control. Therefore, when the frequency in area 2 reaches values below 49.9 Hz, the controller starts to increase the power injection in this area as well. Adding a frequency droop controller to the GSVSC of area 2 will limit the power that is exchanged with the area undergoing a disturbance based on the frequency change.

The oscillations in the power injections, DC line currents and DC voltages and in the current references for the two areas are due to the dead-bands employed in the frequency droop controllers of both GSVSCs. The oscillations for AC area 2, due to the dead-band used, are detailed in Figure 51. When the frequency reaches the value of 49.9 Hz for area 2, the frequency droop controller is activated and the power in the area is corrected such that the frequency deviation is reduced. However, when the frequency first reaches the limit value of the dead-band, the correction is almost instantaneous, which makes the frequency oscillate for a short time.
period within and without the dead-band values. The ratings of the AC systems and the VSCs play an important role in the occurrence of the oscillations.

For the tests performed, the AC systems have a rating of 900 MVA and the VSCs have a rating of 900 MW. In real situations, the rating of the AC system would be much higher compared to the converters. Considering a large AC system, in the order of GVA and the same MW rating for the VSC, there will be an important difference to what the converter can supply to the AC system in case of a load change increase. For the same frequency deviation, the power required by the much
larger AC system will not be fully supplied by the converter from the multi-terminal DC network. Therefore the frequency deviations will not be as significantly corrected as for a smaller system. Since for large AC systems the frequency deviation will not be improved as significantly at the moment when the frequency reaches values outside the dead-band, it will not have the oscillating behavior as with a smaller system. Therefore the oscillations will be reduced or eliminated. However, this translates in a hardship to overcome the frequency disturbance in case of a large AC system with the use of only one secondary AC area that can exchange frequency reserves through the VSC-HVDC.

The DC voltages’ behavior is the same as in the previous scenario, and this is due to the converters operating in DC voltage droop control. The DC currents however follow the behavior of the power injection into each of the two AC areas. At first the currents are increasing, in order for the frequency in area 3 to be stabilized. When the frequency in area 2 starts decreasing, the DC line currents are also being limited, in order not to create large disturbances in this AC system.

Figure 52 DC currents and voltages in the MTDC for GSVSC 2 and 3 with frequency droop control

Figure 53 presents the frequency response of the two AC areas. Compared to the case without frequency control added, it is clear that the frequency response can be improved by this method.
However, when compared to the frequency control added only in the GSVSC of area 3, the frequency response in area 3 was less improved, but the frequency disturbance in area 2 was also limited. Therefore, the addition of a frequency droop control in all the converters can still enhance the frequency response of a system undergoing a disturbance.

The benefit of employing the frequency droop control, in all the converters with respect to only the converter where the load change occurs, is that although the frequencies will be disturbed in other areas, the systems will undergo more reduced deviations. However, for larger disturbances the stability of the AC system where the load change takes place will be compromised if the power being redirected is limited. Therefore, when making a choice between all converters using the frequency controller or just one, the nominal ratings of the systems involved influence greatly the behavior of the frequency response.

The frequency minimum in area 3 is higher than with no control but lower than using frequency droop control in only GSVSC 3 and reaches a value of 49.37 Hz. The frequency in area 2 reaches a value of 49.76 Hz, which is lower than with no control method (50 Hz) but it is improved compared to the previous scenario with only the GSVSC 3 equipped with the frequency droop control, 49.68 Hz.

Figure 53 Frequency response in AC areas for GSVSC 2 and 3 with frequency droop control
The comparison for the frequency droop tests is made in Figure 54. The NADIR values reached by the frequency in the cases of frequency droop control in the VSC of area 3 or in the VSCs of areas 2 and 3 are compared. If a frequency droop controller is used in only area 3, where the load change occurs, then the frequency deviations are reduced compared to the case in which controllers are used in both GSVSCs. This is because the frequency deviation in the second area is not limited.

![Figure 54 Frequency response chart for frequency droop control](image)

Based on the results obtained, using frequency droop controllers, in either one or both GSVSCs, improves the primary frequency response of the AC area under disturbance as compared to the case without control.

### 6.1.3. Frequency droop control gain sensitivity

For the frequency droop control gain sensitivity test both grid-side VSCs have been equipped with frequency droop controllers. The frequency response for the two AC systems is presented in Figure 55. The same load step of 30 MW as in the previous simulations has been considered. The ratings and parameters of the systems have been maintained and can be seen in Appendix A. The full extent of simulation graphs and results can be seen in Appendix E.

Since both GSVSCs use the frequency droop control method the frequency excursions of system 2 will be limited as compared to the case when only the GSVSC 3 would employ a frequency controller.

By using a higher gain in the frequency droop controllers, the frequency deviations in AC area 3 will be reduced. However, the frequency excursions in area 2 will be more severe. Using a lower gain will lead to stronger deviations in the frequency of the system undergoing a disturbance, but the frequency of the second AC system will deviate less. Therefore, the gain should be carefully chosen, based on the existing systems, as to not create larger disturbances or propagations of faults from one area to the other.

The frequency excursions depend on the nominal ratings of the AC systems as well as those of the VSC converters. In the simulations conducted, the AC systems have the rating of 900 MVA and the converters have the rating of 900 MW, making them similar in power capacities. In real scenarios, the ratings between the two systems would be different. For large AC systems compared to the VSC rated power, it is expected that the frequency response will be less.
impacted with the considered gains. In order to improve the primary frequency response, more power reserves, than the VSC can supply, will need to be exchanged. In case both AC systems would be in the order of GVA and the VSC in the order of MW, the frequency in the area where the disturbance occurs will not be improved as much as in the case of a smaller AC system. The frequency in second area will as well be less disturbed by the change in power flow in the MTDC network.

![Graph](image)

**Figure 55 Frequency response for frequency droop control added to all the GSVSC**

The changes in the states of the multi-terminal HVDC meshed grid can be seen in Table 5, while the exact frequency changes, the NADIR and ROCOF, in Figure 56 and Figure 57.

**Figure 55, Figure 56 and Figure 57** present the frequency response with respect to the sensitivity of the frequency droop controller. The frequency NADIR in AC area 3 is increased with increasing the droop gain; however, the frequency NADIR in AC area 2 is reduced. Therefore, a compromise needs to be made when choosing this parameter. The frequency recovery in one area is done at the expense of other areas. The systems’ ratings are important as well because larger systems would be less impacted by the exchange of primary frequency reserves than smaller ones.
Table 5 New states of the MTDC network for frequency droop parameter sensitivity test

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Ref. value</th>
<th>New value</th>
<th>% change</th>
<th>New value</th>
<th>% change</th>
<th>New value</th>
<th>% change</th>
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</thead>
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<td>K&lt;sub&gt;p&lt;/sub&gt; = 5</td>
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<td></td>
</tr>
<tr>
<td>I&lt;sub&gt;line1&lt;/sub&gt;[A]</td>
<td>843.2</td>
<td>834.88</td>
<td>-0.987</td>
<td>826.57</td>
<td>-1.972</td>
<td>820.62</td>
<td>-2.678</td>
</tr>
<tr>
<td>I&lt;sub&gt;line2&lt;/sub&gt;[A]</td>
<td>1420.8</td>
<td>1428.7</td>
<td>0.556</td>
<td>1436</td>
<td>1.070</td>
<td>1441.2</td>
<td>1.436</td>
</tr>
<tr>
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<td>592.95</td>
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<td>606.4</td>
<td>4.986</td>
<td>616.01</td>
<td>6.650</td>
</tr>
<tr>
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<td>-0.293</td>
<td>237.38</td>
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<tr>
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<tr>
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<td>-21.177</td>
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<td>1.010</td>
<td>468.41</td>
<td>1.912</td>
<td>472.57</td>
<td>2.818</td>
</tr>
</tbody>
</table>

Based on the results obtained, the rate of change of the frequency is reduced for area 3 by increasing the frequency droop parameter; however it is increased for area 2. Therefore, as in the previous case for the frequency NADIR, a compromise needs to be made for the frequency droop parameter, in order not to improve the primary frequency response of one system at the expense of the other.

![Frequency NADIR for frequency droop sensitivity test](image1)

![The ROCOF for frequency droop parameter sensitivity test](image2)
Based on the simulations conducted, a higher frequency droop gain will improve the frequency response of the AC area undergoing a disturbance, while for the secondary area it will reduce the stability.

The AC system’s rating and the VSC’s rating have important consequences on the sensitivity of the parameter. When choosing the correct parameters, the size of the systems involved will dictate the amount of power reserves that can be exchanged.

6.1.4. DC voltage droop regulator proportional gain sensitivity

The voltage droop control proportional gain has been varied in order to perform the sensitivity on the frequency response of the parameter. The results obtained are presented in Table 6, Figure 58 and Figure 59. The full extent of simulation graphs and results can be seen in Appendix E.

Based on the simulations performed it was noticed that as the proportional gain increases, the DC line currents change and the DC voltage change is reduced. An increase of the proportional gain leads to lower deviations from the reference value for the line currents and the DC voltages.

<table>
<thead>
<tr>
<th>State</th>
<th>Ref. value</th>
<th>New value</th>
<th>% change</th>
<th>New value</th>
<th>% change</th>
<th>New value</th>
<th>% change</th>
<th>New value</th>
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<tr>
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<td>-3.282</td>
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<td>-2.678</td>
<td>823.53</td>
<td>-2.333</td>
<td>825.38</td>
</tr>
<tr>
<td>I_{line2} [A]</td>
<td>1420.8</td>
<td>1444.2</td>
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<td>1441.2</td>
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<td>1.309</td>
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</tr>
<tr>
<td>I_{line3} [A]</td>
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<td>623.17</td>
<td>7.890</td>
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<td>612.24</td>
<td>5.997</td>
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</tr>
<tr>
<td>V_1 [kV]</td>
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<td>235.99</td>
<td>-1.061</td>
<td>237.38</td>
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<td>V_2 [kV]</td>
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<td>231.03</td>
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<tr>
<td>V_3 [kV]</td>
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<td>-1.152</td>
<td>229.88</td>
<td>-0.052</td>
<td>229.18</td>
<td>-0.357</td>
<td>229.37</td>
</tr>
<tr>
<td>P_2 [MW]</td>
<td>62</td>
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<td>43.32</td>
<td>-30.129</td>
<td>43.21</td>
<td>-30.306</td>
<td>43.69</td>
</tr>
<tr>
<td>P_3 [MW]</td>
<td>459.62</td>
<td>471.71</td>
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<td>472.57</td>
<td>2.818</td>
<td>470.72</td>
<td>2.415</td>
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</tbody>
</table>

The results for the frequency response show important consequences. With the increase of the proportional gain of the DC voltage droop control, even though the frequency NADIR in area 3 is only marginally improved, the frequency NADIR in area 2 does exhibit some improvement. Therefore, it can be seen that as with choosing a higher frequency droop gain, a higher DC droop proportional parameter will ensure a better frequency response. However, in the case of the DC voltage droop proportional gain, the NADIR for both systems has been improved.
Increasing the DC droop regulator proportional parameter leads to an improvement in the rate of change in the frequency deviation. The ROCOF is reduced with the increase of the proportional gain, for both the AC area 3 which undergoes a disturbance condition and the AC area 2 with which power reserves are exchanged. As with the NADIR values, both systems show an improvement in the frequency response if the DC voltage droop proportional gain is increased.

Based on the results obtained, the primary frequency response of both AC systems has been improved if the DC voltage droop proportional gain was increased.
6.2. Synthetic inertia emulation control for the VSC-HVDC

The second method of strengthening AC system’s frequency response in case of disturbance is using, at the VSCs of multi-terminal DC network, synthetic inertia emulation controllers. For the simulations, the same meshed multi-terminal DC topology as in the previous case has been used. This system is presented in Figure 44. The full voltage-source converter with the synthetic inertia emulation control method is presented in Figure 27. Both GSVSCs use the DC voltage regulator in droop based control method.

The synthetic inertia emulation control has been tested in the same way as the previous frequency controller. First, only the GSVSC of the AC area 3, where the load change occurs, is equipped with the synthetic inertia emulation controller. Second, both GSVSCs are fitted with synthetic inertia emulation controllers. Finally, the inertia constant that has been assigned to the VSC is changed in order to investigate the sensitivity of the frequency response to the parameter.

6.2.1. Synthetic inertia control added to the GSVSC 3

From the simulations performed, the power provided to the two AC areas is presented in Figure 60, with the d-axis current reference from the outer controllers of the converters. The reactive power and the q-axis currents reference from the outer controllers of the GSVSC are presented in Appendix F, since all the reactive components are zero and do not change throughout the test. The load change in the system is of 30 MW, active power while the reactive power is kept at a value of zero.

The parameters for equation 4.4-1 and 4.4-2 have been chosen as suggested in [37]. The value of the inertia constant for the converters was set to $H_{VSC} = 3$ for the present test. The capacitance of the DC capacitors has been chosen as 3mF in order to provide more stored energy. Since the DC line has been developed as mono-polar, the number of capacitors at each converter is $N = 1$. The initial fundamental frequency is $f_0 = 50$ Hz, however there are normal operation oscillations and a dead-band is employed for the frequency measurement at the PLL. The reference value of the DC voltage for the area 3 is $U_{dc0} = 230$ kV.

As in the previous control simulations, the load in the AC area 3 is increased at $t = 2s$. Because of the dead-band employed, the power supplied in area 3 starts increasing at $t = 2.8s$, when the frequency in the area drops below the value of 49.9 Hz, which is the lower limit of the dead-band. At the same moment, the power supplied in area 2 starts decreasing. The oscillations occurring at $t = 2.8s$ in the current and power graphs are due to the dead-band employed for the synthetic inertia control. When the converter begins to correct the frequency deviation in area 3 by supplying more power in the node, the frequency is slightly increased and therefore it reaches values inside the dead-band again, where the converter stops its frequency support. A zoomed-in frame is presented for the oscillations occurring in the power injected in area 3.
The DC line currents and the DC node voltages are presented in Figure 61. Because the topology used in the model is the meshed topology, when the load change occurs in area 3, the DC current of line 1 is decreased. Line 1 is the DC link between the wind park and the AC area 2. The DC currents for lines 2 and 3 that supply AC area 3 show an increase.

The DC voltages exhibit the same behavior as in the previous tests and they decrease until the frequency reaches a minimum at which point they return to the initial reference value. However, as in the present case, the DC voltages does not recover to the initial reference value. The voltage comes close to the initial value but does not reach it since after a disturbance, the frequency does not return to the 50 Hz value. The frequency remains at a slightly lower operating point in order for the secondary frequency control to participate in the frequency support. Since the frequency does not recover to the 50 Hz value, this difference in frequency will change the reference value of the d-axis current. Therefore, the voltages will not return to the reference values after the disturbance.
Figure 61 DC line currents and DC node voltages for multi-terminal DC with GSVSC 3 fitted with synthetic inertia emulation control

The last figure presented is the frequency response of the two AC systems in Figure 62. It is clear that the frequency response in area 3 is supported by the synthetic inertia emulator controller added to the GSVSC 3. However, the frequency in area 2 decreases as well and without limitations or controls added to its GSVSC the frequency deviations can be larger than the synchronous generator and governing system can handle. In such a scenario, frequency support for AC area 3 will be performed but the area 2 will undergo severe frequency disturbance.

For the situation tested in this chapter, the load step has been small compared to the system’s rating, such that even without an added control the AC areas would still be able to recover the frequency disturbance and continue within normal operating conditions. If the load step would have been higher or a different more severe disturbance would have occurred, the frequency in area 3 would have dropped to lower value and the GSVSC would have supplied more power to the system under disturbance. This would have reduced the power being supplied in area 2 and therefore, area 2 would have undergone large deviations from the nominal frequency value.

Because no limitations have been used for the frequency deviations in area 2, the frequency response of area 3 has been improved at the expense of the secondary area.
The frequency response of area 3 has been improved by using the synthetic inertia emulation control at the GSVSC of the area undergoing a disturbance. However, the frequency in area 2 has been reduced. The interest is therefore to test the synthetic inertia emulation control with both GSVSC equipped with this method. This will be simulated in the following subchapter.

6.2.2. Synthetic inertia emulator controller added to all converters

The parameters employed in the present simulations are the following:

- VSC inertia constant $H_{VSC} = 3s$
- DC capacitors $C_{dc} = 3 \text{ mF}$
- Number of capacitors $N = 1$
- Nominal frequency value $f_0 = 50 \text{ Hz}$
- Reference value for node 3 $U_{de03} = 230 \text{ kV}$
- Reference value for node 2 $U_{de02} = 233.47 \text{ kV}$

The same AC systems and VSC-HVDC have been used in the testing. A load increase of 30 MW occurs at $t = 2s$, in AC area 3. The power in the AC area is active only and therefore no changes or deviations from the zero value will occur for the reactive power measurement or the q-axis
current references. The entire list of results can be seen in Appendix F. The results for the power dissipated in the choppers and the results for the machine field voltage and mechanical power are presented in Appendix F.

The power supplied to the AC area 3 increases starting at $t = 2.8s$, when the frequency in the area reaches values below 49.9 Hz, which is the lower limit of the dead-band. At the same moment, the power supplied in area 2 begins to decrease. This behavior is similar with the behavior from the previous test when only one converter is fitted with the synthetic inertia emulation controller. Oscillations occur in this case as well and they are due to the dead-band used for the frequency measurement at the PLL and due to the similar rating of the AC systems and the VSC.

![Figure 63](image)

**Figure 63** Power supplied to areas 2 and 3 with both GSVSCs using synthetic inertia emulation controllers

Compared to the previous scenario, the power supplied to the two AC areas as well as the reference d-axis currents show more oscillations. The increased number of oscillations takes place due to the dead-band employed for the second GSVSC synthetic inertia emulation controller. The same oscillations can be seen in Figure 64, in the DC line currents’ behavior.
When the frequency in area 2 starts decreasing below the 49.9 Hz value, the power being supplied to this area increases as well. This is done by decreasing the power that is supplied in area 3. Therefore, by employing the synthetic inertia emulation controllers in both GSVSC converters, a balance is achieved between the powers supplied to the two areas. Because the load is increased in the AC area 3, the current injections toward this node area are changed by changing the DC node voltages. In Figure 64, the currents of line 2 and 3 show an increase. The current flowing from the wind park toward the second area, the current of DC line 1, is decreased. This leads to a decrease in the power being supplied in AC area 2 and an increase in the power to area 3.

The DC voltages show the same type of behavior in this scenario as the previous ones. The voltages reach new operating points. These are computed with the help of the state-space model of the HVDC system. The same steady state-error can be seen in the DC voltages results as in the previous scenario with only GSVSC 2 equipped with the frequency controller.

Figure 65 presents the frequency response for the two AC areas. Similar to the previous cases, the frequency deviation from the nominal value in area 3 is reduced. However, the new value of the NADIR is lower than in the case where one converter utilizes the synthetic inertia emulation controllers.
controller. The reason is that the frequency controller in area 2 intervenes to maintain the frequency deviations in this area to a minimum.

**Figure 65** Primary frequency response with both GSVSCs using synthetic inertia controllers

Using synthetic inertia controllers in both GSVSCs ensures that the frequency response in one system is improved while the second system does not undergo too large deviations. The comparison between one or both converters using the synthetic inertia controller can be seen in Figure 66.

**Figure 66** Frequency response chart for synthetic inertia using DC capacitors
6.2.3. Synthetic inertia emulation control and frequency droop control at GSVSC 3

For the present test the GSVSC of AC area 3 has been modelled with both the frequency droop control and the synthetic inertia emulation control method. The frequency response can be seen in Figure 67. Because the GSVSC of area 2 does not use any frequency control or any limitation the frequency will decrease significantly in this system. However, for the simulations performed, the synchronous generator and the governing system are sufficient to return to a normal operating condition. The entire list of results can be seen in Appendix F.

![Figure 67 Primary frequency response for areas 2 and 3 with GSVSC 3 fitted with frequency droop control and synthetic inertia emulation control](image)

The converter of area 3 uses two frequency control methods and therefore it is expected that the frequency would be maintained at values closer to the nominal one. Although this is shown in Figure 67, it can also be seen that the recovery of the frequency to the nominal value does not occur. This is due to the synthetic inertia controller, which is based on measuring the AC frequency and changing the DC reference value. Because after a disturbance in an AC system the frequency does not return to its nominal value, but stabilizes at a lower value, the measurement preformed at the AC side through the PLL would introduce a steady-state error in the DC voltages and currents.
6.2.4. Synthetic inertia control – VSC inertia constant sensitivity

The synthetic inertia emulation method uses an inertia constant that is assigned to the VSC converter. The purpose of the inertia constant is to emulate the constant used in synchronous machines. For synchronous generators, the higher the inertia constant the lower the deviations are from the nominal frequency, in case of a disturbance. The sensitivity of the $H_{vsc}$ has been tested for values of 1, 3 and 5. The results are presented in Figure 68.

![Figure 68 H\textsubscript{vsc} constant sensitivity](image)

The tests performed show that the inertia constant of the converter has the same behavior as the inertia of a synchronous generator. The higher the values used, the lower the deviation from the nominal frequency is. This is an expected behavior, since the inertia constant is defined as the kinetic energy stored in the machine. Therefore, the higher the amount of energy stored, the lower the deviation from the nominal frequency will be.
6.3. Synthetic inertia control using the frequency derivative added to the VSC-HVDC

The last method used in simulations for the AC frequency support by VSC-HVDC, is the synthetic inertia using the frequency derivative. The model implemented for the outer controller of the VSC is presented in Figure 26. The simulations have been conducted in the case where the synthetic inertia controller has been added to the converter of the AC area 3, where the load change occurs, and in the case when the synthetic inertia controllers have been added to both GSVSCs. The last set of simulations is performed to quantify the sensitivity of the gain of the synthetic inertia on the frequency response of AC system 3. The same model, presented in Figure 44, has been employed to test the synthetic inertia control using the frequency derivative.

6.3.1. Synthetic inertia control added to the GSVSC 3

The present tests have been performed for the case with synthetic inertia controller added to the converter of the AC system area 3. A dead-band has been used to avoid the frequency controllers reacting in normal operating conditions. The frequency derivative has been implemented using a washout filter, since it is mathematically equivalent.

Figure 69 Power supplied to AC areas and current reference for MTDC with df/dt synthetic inertia at GSVSC 3
The load is increased in AC area 3 at $t = 2\, \text{s}$. At this moment the frequency starts decreasing. When the value of 49.9Hz is reached by the frequency, the synthetic inertia controller will increase the power supplied to the area. This can be seen in Figure 69. Because the frequency derivative is used, the change in the power supplied in the area has a fast increase. This will create higher oscillations in the two AC systems, as compared to the other frequency controllers. The oscillations are present in the power injected to the areas, the DC node voltages and the DC line currents for both GSVSCs. The nominal ratings of the AC systems as well as of the VSCs influence the severity of the oscillations. As mentioned for the previous scenarios, in reality the rating of the AC systems will be much larger than the rating of the converters, therefore reducing the time of the oscillations as well as their severity since the VSC-HVDC system will not influence the frequency response as strongly.

The DC line currents and voltages are presented in Figure 70. The currents show the same behavior as the power supplied to the AC areas. The DC voltages show the decrease that is specific to the increase in current and power supplied to areas 3. The same type of oscillations can be seen in the currents and voltages as in Figure 69. The oscillations are due to the dead-bands used in the synthetic inertia controllers. The change in voltages as currents is steeper compared to the previous frequency controllers. The difference is in the frequency deviation calculation, in this case using a frequency derivative.

Figure 70 DC line currents and DC voltages for MTDC with $df/dt$ synthetic inertia at GSVSC 3
The main difference in the response of the currents and voltages is that although the rate of change of the frequency is improved in the beginning, they do not return to the reference value. The currents in the DC lines reach values, higher than the reference value for line 1 and lower than the reference values for lines 2 and 3. This behavior is opposite to the behavior of the previous frequency controllers. Therefore, the frequency in area 2 will be increased after the NADIR of area 3 is reached and the frequency of area 3 will have a much slower recovery. The reason behind this is the derivative used in the synthetic frequency control method. It reduces the recovery of the frequency response, which can be seen in Figure 71. The control method improved the rate of change and the frequency NADIR, however the recovery of the frequency is slower and induces a frequency increase as well in the secondary area. After \( t = 20 \)s simulation time, power begins to be reduced from area 3 and pushed into area 2, creating a frequency increase in area 2 and a lower frequency recovery in area 3.

![Figure 71](image)

**Figure 71** Frequency response for AC areas for MTDC with df/dt synthetic inertia at GSVSC 3

The field voltage and mechanical power of the synchronous generators as well as the chopper behavior can be found in Appendix G.
6.3.2. Synthetic inertia control added all the converters

The second type of test for the synthetic inertia using the frequency derivative is implemented with the two GSVSCs using the control method. The results are presented in Figure 72. The full set of results can be found in Appendix G. The same type of behavior, as in the previous scenario, for the power supplied to the AC areas, the DC voltages and DC line currents, and the frequency response has been observed.

As in all the methods presented, the use of the frequency control in both GSVSCs limits the frequency decrease in the second area. This is an important feature that needs to be taken into account. A choice between fitting both GSVSCs with the synthetic inertia control method or only one GSVSC needs to be made. The purpose of the controller is to reduce the deviations of the frequency in the area undergoing a disturbance but not to destabilize the frequency of the other AC systems by creating unbalances or propagation of disturbances between systems. The decision is influenced by the power ratings of the systems involved as well. If one AC system is comparatively larger than the other it may not require a frequency controller or it may destabilize the secondary area as well in case it undergoes a disturbance.

![Figure 72 Frequency response for areas 2 and 3 for MTDC with df/dt synthetic inertia at GSVSCs](image-url)
Based on the results obtained, the improvement of the frequency in area 3 is limited when using the synthetic inertia controller in both VSCs as compared to using the controller only in the VSC of area 2. However, in this case the frequency in area 2 is less disturbed. The same increase in the frequency of area 2 can be observed as well, after the frequency NADIR of area 3 is reached.

A comparison between using the synthetic inertia controller only in the VSC of area 3 and using the synthetic inertia controller in both VSCs is presented in Figure 73.

Due to larger oscillations in this method than in the other frequency controllers, it is important to mention that for the synthetic inertia controller using the frequency derivative careful attention is needed in tuning the parameters and gains. For larger AC systems this criteria may not be as important, however for smaller single machine isolated AC systems like in the models used to test the controllers, the tuning is more sensitive than in other methods. Therefore, the last test performed for the synthetic inertia control method using the derivative of the frequency is the sensitivity of the gain $K_p$.

**6.3.3. Sensitivity of the synthetic inertia gain $K_p$**

The last test performed for the synthetic inertia controller using the frequency derivative is for the sensitivity of the $K_p$ gain.

The parameter $K_p$ of the synthetic inertia controller using the frequency derivative requires more tuning than the other gains of the previously modelled controllers. This is due to the fast reaction of the controller in increasing the power injection in the AC system undergoing a disturbance. In order to supply the power that the AC system requires to overcome the frequency deviations the $K_p$ parameter needs to be larger, however, increasing the parameter leads to supplying a larger amount of power when the frequency reaches the 49.9 Hz value and therefore the frequency will oscillate outside and within the dead-band. The reason for this occurring is also the small dimension of the AC system used in the simulations, which is has the rating of 900 MVA while the converter is at 900 MW. The entire simulations results can be seen in Appendix G.

Figure 74 presents the frequency response of the synthetic inertia using the frequency derivative for various sensitivities. As in the previous sensitivity tests, using a higher proportional gain will improve the frequency of area 3, but will also introduce more oscillations. However, without another limitation or the same frequency controller in the GSVSC of area 2, this area will risk
becoming unstable. The higher the gain used, the more reduced the frequency deviation in area 3 is while the deviation in area 2 will be increased and vice versa.

![Frequency response for MTDC with synthetic inertia using df/dt derivative](image)

Figure 74 Frequency response for MTDC with synthetic inertia using df/dt derivative

An important factor of this frequency controller is that the frequency in the second area oscillates more while the frequency response in area 3 is being strengthened. The reason is the longer recovery time for this type of controller.

The frequency NADIR values for the sensitivity of the $K_p$ parameter are presented in Table 9.

<table>
<thead>
<tr>
<th>Speed Governor Parameters</th>
<th>Table 9</th>
</tr>
</thead>
</table>

![Table 7 Frequency NADIR for Kp sensitivity using synthetic inertial controller with df/dt](table)

<table>
<thead>
<tr>
<th>Frequency area 2</th>
<th>Kp = 3</th>
<th>Kp = 5</th>
<th>Kp = 10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum</td>
<td>49.93</td>
<td>49.9</td>
<td>49.84</td>
</tr>
<tr>
<td>Maximum</td>
<td>50.04</td>
<td>50.06</td>
<td>50.11</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Frequency area 3</th>
<th>Minimum</th>
<th>49.2</th>
<th>49.21</th>
<th>49.26</th>
</tr>
</thead>
</table>
6.4. Frequency response and comparison between frequency controllers

Tests have been performed in order to compare the frequency droop control method, the synthetic inertia emulation method and the synthetic inertia using the frequency derivative. The present subchapter will compare the results obtained for the three frequency controllers implemented based on the frequency NADIR and ROCOF.

![Figure 75 Frequency response in area 3](image)

The comparison has been made for the case with both GSVSCs being fitted with the same type of frequency control method. Considering the rate of change of the frequency, a different behavior has been noticed between the controllers. If the frequency droop control and the synthetic inertia emulation control have similar results, the synthetic inertia with the frequency derivative shows a much slower recovery of the frequency. The frequency rate of change of the three control methods can be seen in Figure 75. Both the frequency droop control and the synthetic inertia emulation control show similar recovery rate. The two controllers reach similar values as the synthetic inertia controller using the frequency derivative, after the frequency recovers from the disturbance as well.

The synthetic inertia using the frequency derivative has shown more oscillations compared to the other two control methods. The reason is the use of the frequency derivative, implemented using a washout block, which amplifies the frequency noise.
Regarding the NADIR, reached with the frequency droop, synthetic inertia emulation control and
the synthetic inertia using the frequency derivative, there is not a significant difference between
them. All three methods have been able to show an improvement in the frequency response of the
area undergoing a disturbance, while the frequency in the secondary area is changed. The
frequency droop control and the synthetic inertia emulation control have similar results. This can
be seen in Figure 76. The reason is that the two controllers use the frequency difference in
computing the new values for the d-axis reference currents, while the synthetic inertia using the
frequency derivative uses the derivative to change the power supplied to the area undergoing the
load change.

The synthetic inertia using the frequency derivative has been less efficient in strengthening the
AC system that was under a disturbance condition, but it also did not weaken the AC system in
area 2. As mentioned, the difference in results is due to the derivative being used rather than the
difference from the nominal value.
7. Conclusion and Recommendations

7.1. Conclusion

The current thesis dealt with the comparison of frequency control methods applied to MTDC connected VSC-HVDC stations, in order to facilitate the exchange of primary frequency reserves by artificially coupling the AC systems and therefore strengthening the capability of the AC systems involved to overcome frequency deviations after contingencies. The three frequency controllers investigated are the subsequent: the frequency droop control method, the synthetic inertia emulation control method (as termed in the literature) and the synthetic inertia control method using the frequency derivative. The control methods have been tested on a meshed three-terminal MTDC grid configuration. The converters involved in the frequency support were the two grid-side converters. Tests have been performed for the case with one grid-side VSC or the case with both grid-side converters equipped with the same frequency controller. Sensitivities of various parameters of the controller have been investigated as well.

Based on the simulations presented, the use of frequency control only in one converter, rather than in both GSVSCs, provides better primary frequency support for the area undergoing the disturbance. The reason is the non-limiting of the secondary area’s frequency deviations, which leads to larger exchanges of power between the AC systems. Nevertheless, one particular drawback presented by the lack of limitation on the frequency reserves exchange is the larger frequency excursions of the secondary AC system. Therefore, implementing a frequency controller at the grid-side converter of the area undergoing a disturbance stabilizes the frequency at the expense of the second AC system. However, if there are large differences in the power ratings of the AC systems involved, the stronger AC system may help secure and stabilize the weaker system. It is also important to take into account that in this study the ratings of the AC systems used are 900 MVA and the ratings of the converters are 900 MW. In practice, the converters’ power capacity will be much lower compared to the AC systems’ nominal power.

Simulation results for both grid-side VSCs equipped with frequency controllers have been presented for each of the control method tested. The results have shown an improvement of the primary frequency response for the area undergoing the disturbance. However, the frequency NADIR is lower compared to the case where only one GSVSC uses a frequency controller. The reason is the limitation of the frequency deviations of the secondary AC system, introduced by the frequency control method fitted to the second converter. The frequency NADIR for the secondary area has shown an improvement compared to the previous case. The limitation imposed by the frequency controller on the deviations of the secondary AC system limits the power exchanged with the area under contingency.

The results obtained for the proposed frequency controllers have demonstrated oscillations in the DC node voltages, the DC line currents, the power supplied to the AC areas and the d-axis current references used in the VSC controller. Oscillations occur when the frequency, of the system area undergoing the contingency has reached the limit values of the dead-band and the power supplied to the AC areas is changed. The frequency takes values outside of and within the dead-band’s interval range. Therefore, the frequency controller is active and inactive for a short period of time.
until the frequency decreases further and does not reach values within the dead-band any longer. Based on the dead-band values and the parameters used for the frequency controllers, the oscillations can be improved or they can become more severe. The use of higher values for the gain parameter of the frequency controllers led to more severe oscillations, for systems similar to the ones used in the tests. The reason is the increased amount of power supplied to the area under disturbance which translates to keeping the frequency within the dead-band for a longer time period. In the case where both GSVSCs have used frequency controllers and therefore frequency dead-band limitations, oscillations have occurred for each dead-band employed.

Based on the simulation results presented, the frequency droop controller and the synthetic inertia emulation controller have created deviations in the DC voltage after the frequency disturbance has been recovered. The DC voltage does not return to the reference value after the disturbance condition is overcome. The change is due to the frequency that did not return to the 50 Hz value after the disturbance and therefore a steady-state error was introduced in the DC node voltages and the DC line currents.

From the results obtained, the synthetic inertia using the frequency derivative has shown the lowest recovery rate after the frequency NADIR is reached. The reason behind this is the calculation of the frequency deviation with a frequency derivative and not with a difference.

The sensitivity tests performed for the three controllers’ parameters have exposed the same type of behavior. Using higher values for the gain parameters of the frequency controllers, the frequency response in the system undergoing the disturbance will be improved while the frequency response of the secondary area undergo larger deviations. The mentioned behavior was observed for the frequency droop gain of the frequency droop controller, for the inertia constant of the synthetic inertia emulation controller and for the proportional gain of the synthetic inertia controller using the frequency derivative. The sensitivity test for the proportional gain of the DC voltage droop regulator has shown boosting of the primary frequency response for larger values of the parameter. With higher values for the proportional gain, the frequency response of both AC systems is improved.

The frequency droop controller and the synthetic inertia emulation controller have shown a similar behavior in the parameters investigated both in the AC system and in the VSC-HVDC network. The behavior of the synthetic inertia emulation controller is similar to the behavior of the frequency droop controller. This similarity is determined by the use of the same method applied for calculating the frequency deviation from the nominal value. The synthetic inertia controller that uses the frequency derivative had a different behavior with a steeper increase in the power supplied to the area undergoing a disturbance, because it employs the frequency derivative as a way to detect the frequency change. The fast change in power injected to the AC areas led to more problematic oscillations.

The synthetic inertia controller using the frequency derivative would be more effective in systems with lower inertia and higher ROCOF, while the frequency droop control and the synthetic inertia emulation controller would be more effective in systems with higher inertia and therefore lower ROCOF. A combination of the two may provide the needed primary frequency response. However, all three controllers have been able to improve the frequency deviation and assist the
primary frequency response. The frequency controllers proposed for the use in VSCs of MTDC networks can provide active power support to the areas undergoing a disturbance. This may ease the concern regarding the penetration of renewable energy technologies, if more time can be provided for the active governors to respond.

7.2. Recommendations

During the tests performed the same 900 MVA power rating for the AC systems and 900 MW for the VSCs have been used, making the two systems comparable in size. In practice, power systems will have different ratings, with the AC grids substantially larger than the VSC-HVDC network. One recommendation for future research is testing the frequency controller in a scenario involving larger AC systems, in the range of GW conventional generation. Different ratings for the VSCs and the AC systems will help test the influence of the dead-bands employed as well. Having a smaller VSC-HVDC network compared to the AC systems may reduce the oscillations due to the dead-band limitations. The variation of the power ratings will provide results regarding the stabilizing capability of one weak AC system with the use of a much larger AC grid and therefore a better understanding of the frequency controllers’ behavior can be obtained.

A different more detailed approach in assigning the parameters for the frequency controllers would be from the point of view of a multivariable system. The ratings of the AC systems and VSCs as well as those of the multi-terminal HVDC grid should be considered. The expectancy of the frequency support by exchanging primary frequency reserves needs to be investigated as well.

The frequency controllers’ behavior has been investigated in case of a load increase in one AC system. For further study, it would be important to test other disturbance conditions such as loss of generation unit, decrease in load as well as faults in the AC systems and investigate the strengthening capabilities of the additional controllers as well as the interactions between the AC and the DC systems.

The HVDC has been modelled as a three-terminal meshed topology. One study regarding the behavior of the frequency controllers and the interactions between the AC and DC systems consists in implementing a radial topology for the multi-terminal DC. One other future study is investigating the frequency response capabilities in case more areas are interconnected. It can be assumed that strengthening of the stability of the AC area is achieved if more AC grids are connected and can exchange power reserves.

The frequency control methods have been tested with both GSVSCs using the DC voltage regulator in droop based method. Although the multi-terminal model has been validated for one GSVSC using the DC voltage droop regulator and one VSC in active power control, the behavior of the frequency controllers proposed requires further investigation in such a scenario.
Reference


July 2010.


[26] Zeljko Spoljaric, Kresimir Miklosevic, and Vedrana Jerkovic, "Synchronous Generator

http://www.mathworks.nl/help/physmod/sps/powersys/ref/excitationsystem.html

https://www.mathworks.nl/help/physmod/sps/powersys/ref/hydraulicturbineandgovernor.html


[38] Mario Ndreko, Arjen A. van der Meer, Madeleine Gibescu, and Mart A. M. M. van der Meijden, "Impact of DC Voltage Control Parameters on AC/DC System Dynamics Under

APPENDIX

A. APPENDIX – AC System Parameters

The generator data used for the simulations can be seen in the table below. The data for the excitation system and the hydraulic turbine and governor are presented in Table 9 and Table 10, respectively.

Table 8 Synchronous Generators Parameters

<table>
<thead>
<tr>
<th>Generator data</th>
<th>Nominal Power [MVA]</th>
<th>$S$</th>
<th>900</th>
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<tbody>
<tr>
<td>Voltage [kV]</td>
<td>$V$</td>
<td>230</td>
<td></td>
</tr>
<tr>
<td>Frequency [Hz]</td>
<td>$f$</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Reactances [pu]</td>
<td>$X_d$</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>$X'_d$</td>
<td>0.3</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$X''_d$</td>
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<td></td>
<td>$X_q$</td>
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<td></td>
<td>$X''_q$</td>
<td>0.25</td>
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</tr>
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<td></td>
<td>$X_l$</td>
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<td></td>
</tr>
<tr>
<td>Time constants [s]</td>
<td>$T'_d$</td>
<td>8</td>
<td></td>
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<tr>
<td></td>
<td>$T''_d$</td>
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<tr>
<td></td>
<td>$T'_q$</td>
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<tr>
<td></td>
<td>$T''_q$</td>
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<tr>
<td>Stator resistance [pu]</td>
<td>$R_s$</td>
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</tr>
<tr>
<td>Inertia coefficient [s]</td>
<td>$H$</td>
<td>6.5/4.5/2/5</td>
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<tr>
<td>Friction factor [pu]</td>
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<tr>
<td>Pole pairs [-]</td>
<td>$p$</td>
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<td></td>
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Table 9 Speed Governor Parameters

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<th>Speed Governor data</th>
<th>Servo-motor Gain $K_q$</th>
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<tr>
<td>Gain $T'_d$</td>
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<td>Gate opening limits [pu]</td>
<td>$[g_{min} \ g_{max}]$</td>
<td>[0.01; 0.97518]</td>
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<td>Gate opening limits [pu/s]</td>
<td>$[v_{g_{min}} \ v_{g_{max}}]$</td>
<td>[-0.1; 0.1]</td>
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<td>Perm. Droop [pu]</td>
<td>$R_p$</td>
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<td>Regulator Gain $K_p$</td>
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<tr>
<td>Gain $K_i$</td>
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<td>Hydraulic turbine</td>
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<td>Time constant [s]</td>
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<td>Droop reference</td>
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Table 10 Exciter parameters

<table>
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<th>Parameter</th>
<th>Exciter data</th>
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<tr>
<td>Low-pass filter time constant [ms]</td>
<td>$T_r$</td>
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<tr>
<td>Regulator gain</td>
<td>$K_a$</td>
</tr>
<tr>
<td>Regulator time constant [s]</td>
<td>$T_a$</td>
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<tr>
<td>Exciter gain</td>
<td>$K_e$</td>
</tr>
<tr>
<td>Exciter time constant [s]</td>
<td>$T_e$</td>
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<tr>
<td>Transient gain reduction [s]</td>
<td>$[T_b \ T_c]$</td>
</tr>
<tr>
<td>Damping filter gain</td>
<td>$K_f$</td>
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<tr>
<td>Damping filter time constant [s]</td>
<td>$T_f$</td>
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<tr>
<td>Regulator output limits [pu]</td>
<td>$[E_{f_{min}} \ E_{f_{max}}]$</td>
</tr>
<tr>
<td>Regulator output gain</td>
<td>$K_p$</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
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</thead>
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<tr>
<td>Low-pass filter time constant [ms]</td>
<td>20</td>
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<tr>
<td>Regulator gain</td>
<td>300</td>
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<td>Regulator time constant [s]</td>
<td>0.001</td>
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<tr>
<td>Exciter gain</td>
<td>1</td>
</tr>
<tr>
<td>Exciter time constant [s]</td>
<td>0</td>
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<tr>
<td>Transient gain reduction [s]</td>
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<tr>
<td>Damping filter gain</td>
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<td>Damping filter time constant [s]</td>
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<tr>
<td>Regulator output limits [pu]</td>
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<tr>
<td>Regulator output gain</td>
<td>0</td>
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</tbody>
</table>
B. APPENDIX – MTDC Model

The differential equations for the MTDC model have been built based on the references [29] and [21]. Based on the \( \pi \)-equivalent model of a single HVDC transmission line, a state space model can be developed for a grid composed of three VSC stations.

The first type of network is using a meshed connection.

In the above meshed grid example, the capacitance and inductance of the cables have been considered equal, although this very well may differ in the model. This simplification has been made for easier calculations. The same reasoning has been used for the cables’ resistances.

The incidence matrix, \( I_M \), contains the information regarding the DC cables in the grid. The value of 1 represents the node from which the current injection occurs. The value of -1 is given to the node which is at the collecting end of the current injection while the value is 0 if the node is not included in the connection. Thus, the incidence matrix for the above network has the form:

\[
I_M = \begin{bmatrix}
1 & -1 & 0 \\
-1 & 1 & 0 \\
0 & 1 & 1
\end{bmatrix}
\]
The differential equations for the above network can also be written as:

\[
\begin{align*}
\frac{dx}{dt} &= Ax + Bu \\
y &= Cx + Du
\end{align*}
\]

Where the state matrix \( x \) is defined:

\[
x = [U_{dc1} \ U_{dc2} \ U_{dc3} \ I_{12} \ I_{13} \ I_{23}]^T
\]

And \( u \) is the vector containing the current injections of the VSCs, with the shape:

\[
u = [I_{dc1} \ I_{dc2} \ I_{dc3}]^T
\]

Matrix \( A \) has the shape:

\[
A = \begin{bmatrix}
a_{11} & a_{12} \\
a_{21} & a_{22}\end{bmatrix}_{(n+1)x(n+1)}
\]

The sub-matrices of \( A \) are written as:

\[
a_{11} = [0]_{3x3}
\]

\[
a_{12} = \begin{bmatrix}
-\frac{1}{C_{dc}} & -\frac{1}{C_{dc}} & 0 \\
\frac{1}{C_{dc}} & 0 & -\frac{1}{C_{dc}} \\
0 & \frac{1}{C_{dc}} & \frac{1}{C_{dc}}
\end{bmatrix} = \frac{1}{C_{dc}} [I]_{3x3} \begin{bmatrix}
1 & 1 & 0 \\
-1 & 0 & 1 \\
0 & -1 & -1
\end{bmatrix}
\]

\[
= \frac{1}{C_{dc}} [I]_{3x3} [l_m]^T
\]

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Matrix $B$ has the shape:

$$B = \begin{bmatrix} b_{11} \\ b_{21} \end{bmatrix}_{(n+1) \times n}$$

The sub-matrices of $B$ are written as:

$$b_{11} = \begin{bmatrix} 1 \\ C_{dc} \\ 0 \\ 0 \\ 0 \end{bmatrix}$$

$$b_{21} = [0]_{3 \times 3}$$

The output matrix $C$ is an identity matrix while the output matrix $D$ is a zero matrix.

$$\{ C = [I]_{6 \times 6} \}$$

$$\{ D = [0]_{6 \times 3} \}$$

The second type of connection is a radial one. The state-space form equation for this network will be detailed below.
The same differential equations are valid for the radial network as for the meshed one. The changes occur with incident matrix $I_M$ which has the following shape:

$$I_M = \begin{bmatrix} 1 & 0 & 0 & -1 \\ 0 & 1 & 0 & -1 \\ 0 & 0 & 1 & -1 \end{bmatrix}$$ \[B-14\]

The state-space vector $x$ has the form:

$$x = [U_{dc1} \ U_{dc2} \ U_{dc3} \ U_{dc4} \ I_{14} \ I_{24} \ I_{34}]^T$$ \[B-15\]

The current injection vector $u$ can be written as:

$$u = [I_{dc1} \ I_{dc2} \ I_{dc3} \ I_{dc4}]^T$$ \[B-16\]

The DC current injection, $I_{dc4}$, is considered at the connection node of the three transmission lines, in the same place $U_{dc4}$ is measured.

The sub-matrices for matrix A become:

$$a_{11} = [0]_{4 \times 4}$$ \[B-17\]
Matrix $B$ has the shape:

$$B = \begin{bmatrix} b_{11} & b_{21} \\ b_{21} & (n+1) \times n \end{bmatrix}$$

The sub-matrices of $B$ are written as:

$$b_{11} = \frac{1}{C_{dc}} [I]_{4 \times 4}$$

$$b_{21} = [0]_{3 \times 4}$$

The output matrix $C$ is an identity matrix while the output matrix $D$ is a zero matrix.

$$\begin{align*}
\{ C & = [I]_{7 \times 7} \\
\{ D & = [0]_{7 \times 3}
\end{align*}$$
C. APPENDIX - VSC Model Differential Equations

Figure 79 VSC time-averaged model

From the above figure, the equation can be obtained:

\[ U_{c,abc} - U_{s,abc} = R i_{abc} + L \frac{d i_{abc}}{dt} \]  

The voltage invariant Clark transformation needs to be applied in order to obtain the stationary \( \alpha \beta \) frame of reference from the stationary \( abc \).

\[ \begin{bmatrix} U_\alpha \\ U_\beta \\ U_0 \end{bmatrix} = \frac{2}{3} \begin{bmatrix} 1 & -\frac{1}{2} & -\frac{1}{2} \\ \frac{\sqrt{3}}{2} & 0 & -\frac{\sqrt{3}}{2} \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{2} \end{bmatrix} \begin{bmatrix} U_a \\ U_b \\ U_c \end{bmatrix} \]

For the case study presented in this thesis, which uses symmetrical three phase voltages, \( U_0 \) is equal to zero. Therefore, the equation in the \( \alpha \beta \) frame of reference becomes:

\[ U_{c,\alpha\beta} - U_{s,\alpha\beta} = R i_{\alpha\beta} + L \frac{d i_{\alpha\beta}}{dt} \]
Next, Park’s transformation is employed to obtain the d-q frame of reference:

\[ U_{c,\alpha\beta} = U_{c,dq} e^{j\omega t} \]  
\[ U_{s,\alpha\beta} = U_{s,dq} e^{j\omega t} \]  
\[ i_{\alpha\beta} = i_{dq} e^{j\omega t} \]  

The above set of equations, A-4 to A-6, is replaced in A-3 and the following is obtained:

\[ U_{c,dq} e^{j\omega t} - U_{s,dq} e^{j\omega t} = R i_{dq} e^{j\omega t} + j \omega L i_{dq} e^{j\omega t} + e^{j\omega t} L \frac{di_{dq}}{dt} \]  

By dividing with \( e^{j\omega t} \) the d-q frame of reference equation becomes:

\[ U_{c,dq} - U_{s,dq} = R i_{dq} + j \omega L i_{dq} + L \frac{di_{dq}}{dt} \]  

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The two differential equations for the d-q reference frame can be written:

\[
(U_{c,d} + jU_{c,q}) - (U_{s,d} + jU_{s,q}) = R(i_d + ji_q) + j\omega L(i_d + ji_q) + L \frac{d(i_d + ji_q)}{dt}
\]

\[
= R(i_d + ji_q) + \omega L(ji_d - i_q) + L \frac{d(i_d + ji_q)}{dt}
\]

For the above equations the Laplace transformation is considered:

\[
U_{c,d} - U_{s,d} = Ri_d - \omega Li_q + L \frac{di_d}{dt}
\]

\[
U_{c,q} - U_{s,q} = Ri_q + \omega Li_d + L \frac{di_q}{dt}
\]

The equations can be rewritten:

\[
U_{c,d} - U_{s,d} + \omega Li_q = (R + sL)i_d
\]

\[
U_{c,q} - U_{s,q} - \omega Li_d = (R + sL)i_q
\]

The currents \(i_d\) and \(i_q\) are obtained:

\[
i_d = \frac{U_{c,d} - U_{s,d} + \omega Li_q}{R + sL}
\]

\[
i_q = \frac{U_{c,q} - U_{s,q} - \omega Li_d}{R + sL}
\]

The equations for the currents in the d-q frame are used in the phase reactor of the inner controller.

After the inner controller the VSC voltage references can be computed as follows:

\[
U_{c,d}^{\text{ref}} = (i_d^{\text{ref}} - i_d) \left( k_p + \frac{K_i}{s} \right) + ri_d - \omega Li_q + U_{c,d}
\]

\[
U_{c,q}^{\text{ref}} = (i_q^{\text{ref}} - i_q) \left( k_p + \frac{K_i}{s} \right) + ri_q - \omega Li_d + U_{c,q}
\]
D. APPENDIX – Model validation results

D.1. Model validation point to point topology

Figure 82 Results for sensitivity of the DC Voltage droop parameter, Kp – ptp validation

D.2. Model validation MTDC topology

Figure 83 Results for MTDC topology validation - step up and step down test
Figure 84 Results for MTDC topology validation - step up and step down test

Figure 85 Results for MTDC topology validation - step up and step down test
Figure 86 Results for MTDC topology validation - fault test in the AC area 2 and AC area 3

Figure 87 Results for MTDC topology validation - fault test in the AC area 2 and AC area 3
Figure 88 Results for MTDC validation - sensitivity of the Kp of the DC Voltage controller

Figure 89 Results for MTDC validation - sensitivity of the Kp of the DC Voltage controller
Figure 90 Results for MTDC validation - sensitivity of the Kp of the DC Voltage controller

Figure 91 Results for MTDC validation - sensitivity of the Ki of the DC Voltage controller
Figure 92 Results for MTDC validation - sensitivity of the Ki of the DC Voltage controller

Figure 93 Results for MTDC validation - sensitivity of the Ki of the DC Voltage controller
Figure 94: Results for MTDC validation - sensitivity of the Ki of the DC Voltage controller
E. APPENDIX – Frequency response test results

E.1. Frequency response in point to point topology without any control added to the VSC-HVDC

Figure 95 DC line currents and DC node voltages – no frequency support

Figure 96 Power dissipated by the choppers – no frequency support
Figure 97 Power into AC areas 2 and 3 – no frequency support

Figure 98 Field voltage and mechanical power for the synchronous generators – no frequency support
E.2. Frequency droop control added to the converter at the AC side where the load change occurs

Figure 99 Field voltage and mechanical power for the synchronous generators – frequency droop control at GSVSC 2

Figure 100 Power dissipated in choppers – frequency droop control at GSVSC 2
E.3. Frequency droop control added to all converters

![Graph 1: Field voltage and mechanical power for the synchronous generators—frequency droop control at GSVSC 2 and 3](image1)

![Graph 2: Power dissipated in choppers frequency droop control at GSVSC 2 and 3](image2)

Figure 101 Field voltage and mechanical power for the synchronous generators—frequency droop control at GSVSC 2 and 3

Figure 102 Power dissipated in choppers frequency droop control at GSVSC 2 and 3
E.4. Sensitivity of frequency droop control gain

Figure 103 DC line currents and DC node voltages - frequency droop parameter sensitivity test

Figure 104 Power in AC area 2 and 3 for step in load - frequency droop parameter sensitivity test
Figure 105 Field voltage and mechanical power - frequency droop parameter sensitivity test

Figure 106 Power dissipated in choppers - frequency droop parameter sensitivity test
E.5. Sensitivity of frequency DC voltage droop control proportional gain

Figure 107 DC line currents and DC node voltages - DC voltage droop proportional gain sensitivity test

Figure 108 Power in AC areas 2 and 3 - DC voltage droop proportional gain sensitivity test
Figure 109 Field voltage and mechanical power - DC voltage droop proportional gain sensitivity test

Figure 110 Power dissipated in choppers - DC voltage droop proportional gain sensitivity test
Figure 111 Frequency response for AC areas 2 and 3 - DC voltage droop proportional gain sensitivity test

E.6. Frequency droop control without dead-band

Figure 112 DC currents and DC voltages for MTDC - frequency droop control at GSVSC 3 with no dead-band
Figure 113 Power supplied to AC areas and current reference – frequency droop control at GSVSC 3 with no dead-band

Figure 114 Field voltages and mechanical power – frequency droop control at GSVSC 3 with no dead-band
Figure 115 Frequency response for MTDC – frequency droop control at GSVSC 3 with no dead-band
F. APPENDIX — Synthetic inertia emulation control

F.1. Synthetic inertia control added to the converter at the AC side where the load change occurs

Figure 116 Power supplied to AC areas 2 and 3 and current reference – synthetic inertia emulation at GSVSC 3

Figure 117 Field voltage and mechanical power – synthetic inertia emulation at GSVSC 3
Figure 118 Power dissipated in the choppers – synthetic inertia emulation at GSVSC 3

F.2. Synthetic inertia control added to all converters

Figure 119 Field voltage and mechanical power – synthetic inertia emulation at GSVSC 2 and 3
Figure 120 Power dissipated in the choppers – synthetic inertia emulation at GSVSC 2 and 3

F.3. Synthetic inertia control and frequency droop control added at the AC side where the load change occurs

Figure 121 DC line currents and DC node voltages – frequency droop and synthetic inertia emulation at GSVSC 2 and 3
Figure 122 Power supplied to AC areas 2 and 3 and current references – frequency droop and synthetic inertia emulation at GSVSC 2 and 3

Figure 123 Field voltage and mechanical power – frequency droop and synthetic inertia emulation at GSVSC 2 and 3
F.4. Synthetic inertia control – Hvsc sensitivity

Figure 124 Power dissipated by the choppers – frequency droop and synthetic inertia emulation at GSVSC 2 and 3

Figure 125 DC line currents and DC node voltages– Hvsc sensitivity
Figure 126 Power supplied to AC areas 2 and 3 and current references – Hvsc sensitivity

Figure 127 Field voltage and mechanical power – Hvsc sensitivity
Figure 128 Power dissipated by the choppers– Hvsc sensitivity
G. APPENDIX – Synthetic inertia with frequency derivative results

G.1. Synthetic inertia control added to the converter at the AC side where the load change occurs

Figure 129 Field voltage and mechanical power – synthetic inertia using \( \frac{df}{dt} \) at GSVSC 3

Figure 130 Power dissipated by choppers – synthetic inertia using \( \frac{df}{dt} \) at GSVSC 3
G.2. Synthetic inertia control added to all converters

Figure 131 Power supplied to areas 2 and 3 – synthetic inertia using df/dt at GSVSC 2 and 3

Figure 132 DC currents and DC voltages – synthetic inertia using df/dt at GSVSC 2 and 3
Figure 133 Field voltage and mechanical power – synthetic inertia using $\frac{df}{dt}$ at GSVSC 2 and 3

Figure 134 Power dissipated by the choppers – synthetic inertia using $\frac{df}{dt}$ at GSVSC 2 and 3
G.3. Synthetic inertia control – $K_p$ sensitivity

Figure 135 DC currents and voltages - $K_p$ sensitivity

Figure 136 Power supplied to AC areas and current references - $K_p$ sensitivity
Figure 137 Field voltage and mechanical power - $K_p$ sensitivity

Figure 138 Power dissipated by the choppers - $K_p$ sensitivity
## H. APPENDIX – Worldwide VSC-HVDC installations

### Table 11 Worldwide VSC-HVDC installations

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Year</th>
<th>Power Rating</th>
<th>AC Voltage [kV]</th>
<th>DC Voltage [kV]</th>
<th>Length of DC cables</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hellsjöön, Sweden</td>
<td>1997</td>
<td>3 MW ± 3 MVAr</td>
<td>10</td>
<td>± 10</td>
<td>10 (overhead cables)</td>
</tr>
<tr>
<td>Gotland HVDC Light, Sweden</td>
<td>1999</td>
<td>50 MW ± 50 MVAr</td>
<td>80</td>
<td>± 80</td>
<td>2 x 70 (submarine cables)</td>
</tr>
<tr>
<td>Eagle Pass, USA</td>
<td>2000</td>
<td>36 MW ± 36 MVAr</td>
<td>138</td>
<td>± 15.9</td>
<td>Back-to-back HVDC light station</td>
</tr>
<tr>
<td>Tjæreborg, Denmark</td>
<td>2000</td>
<td>8 MVA 7.2 MW -3 to 4 MVAr</td>
<td>10.5</td>
<td>± 9</td>
<td>2 x 4.3 (submarine cables)</td>
</tr>
<tr>
<td>Terrenova Interconnection (Directlink), Australia</td>
<td>2000</td>
<td>180 MW -165 to 90 MVAr</td>
<td>110 – Bungalora 132 – Mullumbimby</td>
<td>± 80</td>
<td>6 x 59 (underground cable)</td>
</tr>
<tr>
<td>Murray Link, Australia</td>
<td>2002</td>
<td>220 MW -150 to 140 MVAr</td>
<td>132 – Berri 220 – Red Cliffs</td>
<td>± 150</td>
<td>2 x 180 (underground cable)</td>
</tr>
<tr>
<td>CrossSound, USA</td>
<td>2002</td>
<td>330 MW ± 150 MVAr</td>
<td>354 – New Heaven 138 – Shoreham</td>
<td>± 150</td>
<td>2 x 40 (submarine cables)</td>
</tr>
<tr>
<td>Troll A offshore, Norway</td>
<td>2005</td>
<td>84 MW -20 ro 24 MVAr</td>
<td>132 – Kollsnes 56 – Troll</td>
<td>± 60</td>
<td>4 x 70 (submarine cables)</td>
</tr>
<tr>
<td>Estlink, Estonia-Finland</td>
<td>2006</td>
<td>350 MW ± 125 MVAr</td>
<td>330 – Estonia 400 – Finland</td>
<td>± 150</td>
<td>2 x 31 (underground) 2 x 74 (submarine)</td>
</tr>
<tr>
<td>NORD E.ON 1, Germany</td>
<td>2009</td>
<td>400 MW</td>
<td>380 – Diele 170 – Borkum 2</td>
<td>± 150</td>
<td>2 x 75 (underground) 2 x 128 (submarine)</td>
</tr>
<tr>
<td>Caprivi Link, Namibia</td>
<td>2009</td>
<td>300 MW</td>
<td>330 – Zambezi 400 – Gerus</td>
<td>350</td>
<td>970 (overhead lines)</td>
</tr>
<tr>
<td>Valhall offshore, Norway</td>
<td>2009</td>
<td>78 MW</td>
<td>300 –Lista 11 – Valhall</td>
<td>150</td>
<td>292 (submarine cables)</td>
</tr>
</tbody>
</table>