SUB-SYNCHRONOUS OSCILLATIONS BETWEEN FPC WIND FARMS, VSC-HVDC LINKS AND NUCLEAR POWER PLANTS

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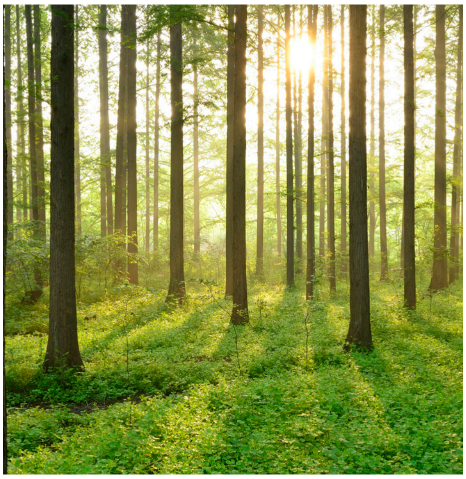

NUCLEAR

GRID INTERFERENCE ON NUCLEAR POWER PLANT OPERATIONS

Energiforsk

Sub-synchronous oscillations between FPC wind farms, VSC-HVDC links and nuclear power plants

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Foreword

Sub-synchronous phenomena can, if present, pose a threat to large turbine-generator sets like the ones used at nuclear power plants. Currently, a lot of inverter connected production such as full power converter wind farms are being installed and more HVDC connections are being built. These large-scale power electronics-based components might bring resonance phenomena into the system. Of special concern are the oscillation frequencies that coincide with the torsional modes of the turbine sets of the nuclear power plants.

The aim of this project was to strengthen the general understanding on how voltage source converter HVDC links and FPC wind farms affect the existence of problematic sub-synchronous oscillation modes. Furthermore, to define general criteria for assessing how exposed a nuclear power plant or part of a power system is to SSO.

The study was carried out by experts Andreas Petersson and Lena Max at Protrol. It is part of the Grid Interference on Nuclear power plant Operations, GINO, program that is financed by The Swedish Radiation Safety Authority, Svenska Kraftnät, Vattenfall, Uniper/Sydkraft Nuclear, Fortum, Skellefteå Kraft and Karlstads Energi.

Sammanfattning

Som ett resultat av förändringen i kraftsystemet med en större andel komponenter inkopplade via kraftelektroniska omriktare, finns det ett ökande intresse för att studera sub-synkrona oscillationer som inkluderar dessa komponenter. I den här rapporten studeras metoder för utvärdering av dessa sub-synkrona oscillationer.

Det finns många möjliga topologier för spänningsstyva omriktare (VSC) kopplade till nätet som beskrivs i den här rapporten. Den del av omriktaren som har liknande bandbredd som de sub-synkrona oscillationerna är styrningen av omriktaren. Modulationen av omriktaren, vilket är det som skiljer de olika topologierna åt, är på en mycket högre frekvens och kan därmed försummas vid studier av sub-synkrona oscillationer. Vid sub-synkrona oscillationer för en VSC är orsaken till oscillationerna ofta den fas-låsta loopen (PLL) eller styrningen av aktiv eller reaktiv effekt, tex styrning av AC spänningen. Styrningen av en omriktare anpassas efter omriktarens önskade funktion och det kan ge en stor variation för tidskonstanterna. Därmed kan det inte dras några generella slutsatser om vid vilka frekvensintervall omriktare är speciellt benägna att bidra till sub-synkrona oscillationer.

Ett vanligt första steg för att hitta de omriktare där det finns en risk för sub-synkrona oscillationer med en synkrongenerator är att göra en scanning med hjälp av en ”unit interference factor” (UIF). Värdet på UIF visar om generatorn och omriktaren är tillräckligt stora och tillräckligt nära varandra i förhållande till nätstyrkan för att det ska finas en risk för sub-synkrona oscillationer.

Det finns olika metoder för att utvärdera risken för sub-synkrona oscillationer för de generatorer och omriktare som har identifierats. Olika metoder av frekvensscanning är fördelaktiga att använda för större system som också kan innehålla ”black-box” modeller. För att utvärdera ett system som innehåller en synkrongenerator används ofta ”complex torque method” som ger den elektriska dämpningen sett från generatorn. Med den metoden ges dämpningen för hela systemet och bidraget från en VSC kan studeras genom att jämföra den elektriska dämpningen för systemet med och utan VSCn.

Vid en negativ eller låg elektrisk dämpning vid generatorns svängningsfrekvenser finns det en risk för odämpade sub-synkrona oscillationer. Om den mekaniska dämpningen inte är känd kan tidssimuleringar avgöra om det uppstår oscillationer. Tidssimuleringar är även ett viktigt komplement till frekvensscanningar för att få med icke-linjära fenomen. En annan metod för att utvärdera delar av ett system är att göra en frekvensscanning av impedansen eller admittansen genom dynamiska tidssimuleringar. Impedansen tas fram för varje frekvens och en låg eller negativ resistans vid synkrongeneratorns svängningsfrekvenser indikerar att det finns en risk för odämpade oscillationer. För oscillationer som inte inkluderar en synkrongenerator används frekvensscanning av impedans eller admittans.

Om det är en hög risk för sub-synkrona oscillationer och prestandan för omriktaren inte ska ändras kan en dämpregulator läggas till som dämpar ut de aktuella frekvenserna. Dämpregulatorn är väl studerad och används för HVDC-omriktare.

Olika faktorer har visats öka risken för SSO. En stor synkrongenerator och en stor VSC i förhållande till nätstyrkan ökar risken för SSO. Risken för SSO ökar även om generatorn och VSCn ligger nära varandra elektriskt.

Summary

With the change in the power system with a larger share of components connected via power electronics there is an emerging interest for sub-synchronous oscillations (SSO) including these components. In this report, the study methods for the sub-synchronous oscillations are evaluated.

For the grid connected voltage source converters (VSCs), there are many different topologies, which are described in this report. However, looking at the characteristics in the frequency range of sub-synchronous oscillations, it is the control of the converter that has similar bandwidth. The modulation of the converter, which is different for different topologies, is at a much higher frequency and can therefore be neglected in the study of sub-synchronous oscillations. When having sub-synchronous oscillations including a VSC, it is often either the phase locked loop (PLL) or the control of the active or reactive power, for example an AC voltage controller, that is a reason for the amplification of the oscillation. These control loops are designed depending on the application of the converter and can have a wide range of risetimes. Therefore, no general conclusions can be made on frequency intervals where VSCs are especially prone to participate in sub-synchronous oscillations.

When studying the risk of possible oscillation, a first step is usually to make a screening of the VSCs located nearby the synchronous generator. This is made by the unit interference factor (UIF) that gives if the generator and a VSC are large enough and close enough in relation to the grid strength to have a risk of amplified sub-synchronous oscillations.

When having identified the generator and the VSC where there is a risk for oscillations, there are different study methods. For evaluating larger systems that can also include black box models, frequency scanning methods can be used. For a system including a synchronous generator, the complex torque method can be used and gives the electrical damping seen from the generator. For this method, the damping is given for the whole system and the contribution from the VSC can be seen by comparing the electrical damping with the VSC to the electrical damping without the VSC.

If the electrical damping is low, or negative, at the torsional mode frequencies for the generator shaft, there is a risk for an amplified sub-synchronous oscillation. If the mechanical damping is not known, a time domain simulation can be used to see if there will be any oscillations. Time domain simulations are also useful for including non-linearities in the model and is an important complement to the frequency scanning methods. Another method for evaluating parts of the system or a single component is frequency scanning of the admittance/impedance by dynamic simulations. Here, the impedance or admittance is obtained for each frequency and a low or negative resistance at the torsional mode frequency indicates a risk of amplified sub-synchronous oscillations. If there are oscillations not including a synchronous generator, the impedance scanning is used.

If there is a high risk of sub-synchronous oscillations, and the performance of the VSC should not be changed, a damping controller can be added. This damping will eliminate the amplification at the specified torsional frequencies. The damping controller is well studied and is used in HVDC converters.

Different factors are identified to increase the risk of SSO. Having a large synchronous generator and a large VSC compared to the grid strength increases the risk of SSO as well as having the generator and VSC located close to each other.

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1 Background and scope

Sub-synchronous resonance is a phenomenon that has been extensively studied for several years. However, with the change in the power system with a larger share of components connected via power electronics there is an emerging interest for oscillations including these components.

In this chapter a background of studies concerning sub-synchronous oscillations is given as well as the scope of this study.

1.1 BACKGROUND

Sub-synchronous oscillations (SSO) were primarily recognized as a phenomenon occurring due to the use of series capacitors for transmission lines, defined as sub-synchronous resonance (SSR) [3]. The first known occurrence of SSR was in the Mohave Project in 1970 and 1971. The reason for these events was an energy exchange between the series compensated lines and the mechanical system of the plant [6]. As a result, the phenomenon has been studied extensively to avoid the risk of SSR in the power system.

In [9] from 1990, the phenomenon of SSR is discussed in detail as well as studies of the phenomenon. The main focus is on oscillations between power system components (typical series compensation) and the mechanical system of a generator. It is mentioned that also for example HVDC connections can be of interest. In this book, analytical eigenvalue analysis is the main focus but also frequency scanning of system impedance and EMTP (Electromagnetic Transients Program) simulations are mentioned. In [6] from 1996 considering SSR, more focus is given to evaluation using frequency scanning methods.

The current trend in the power system being an increase of components connected by power electronics introduces new risks for sub-synchronous oscillations to occur. The components of concern are typically components with high power such as large wind farms and HVDC connections. As an example, there was an incident in the Zorillo Gulf wind farm in Texas in 2009 where SSR occurred for a DFIG (doubly-fed induction generator)-based wind farm and a series compensated transmission line [10]. This topic has been studied in the Elforsk report [10] where the risk of occurrence of SSR for DFIG wind farms was evaluated using impedance frequency scanning. In [44] it is reported about 58 SSR events between DFIG and series compensation during one year in the Guyuan system, north China. Two factors that influence the stability of the SSR incident are the amount of series compensation and a relatively low production level. It is also concluded in [44] that it is the DFIG turbine that trip due to the SSR incident while none of the wind turbines using full-power converters tripped.

Lately, sub-synchronous oscillations have been studied for many different systems, i.e. that the oscillations occur between different components. In many of these studies also different methods are used for evaluations. There is extensive research ongoing for VSC converters connected to the grid and the risk of SSO including the impact of the control parameters. Mitigation of SSO is standard for HVDC systems but not for wind power due to the different requirements for HVDC connections and for generating units such as wind power.

1.2 SCOPE

The aim of this project is to review the impact of VSC-HVDC and full power converter wind farms on sub-synchronous oscillations with large synchronous generators.

The scope of the work is as follows:

- Identify the different methods that have been used for evaluation of sub-synchronous phenomena.
- For the identified methods, the following should be made:
  - × Describe the theory of the method, what calculations/simulations are made and what data/models are needed.
  - × Describe the conclusions that can be made by the different study methods.
- Summarize the study methods and list the suitability for the different methods depending on the system to be studied.
- Qualitatively describe the wind power converters and the HVDC converters, the physical construction, the controller as well as the protection and mitigation function relevant for SSO.
- Implement the proposed study methods in a test system and comment on the following:
  - × How a study can be performed for a test system with a large synchronous generator and a VSC.
  - × How the risk of SSO is affected by the design of the converter controller.
  - × How the risk of SSO is affected by the location in the system.
  - × How a study can be performed for a test system with two large VSCs.

2 Overview of Sub-synchronous oscillations

Sub-synchronous oscillations can occur between several different components and can either occur during steady state operation or be following a transient event.

In this chapter, general definitions are given for sub-synchronous oscillations, the system of interest is discussed, and a screening method is described.

2.1 DESCRIPTION OF THE SYSTEM OF INTEREST

The studied system can consist of a converter installation, synchronous generator(s), transmission lines and series compensation. In Figure 1, an example of a system is given.

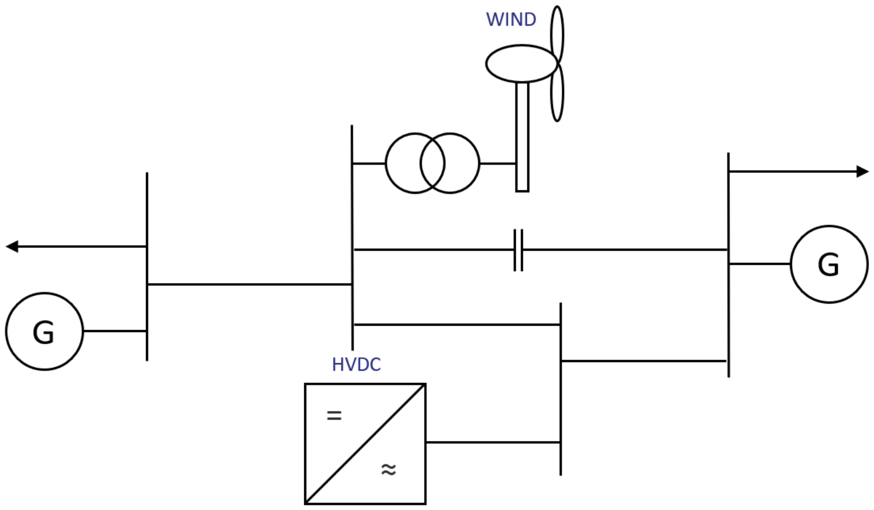

Figure 1 Example of a system for SSO studies

In this study, an example system including a large synchronous generator in combination with grid connected converters, such as an HVDC systems or a large wind power park, is used. However, the suitability of the study methods for other components is also mentioned.

2.2 DEFINITIONS FOR SUB-SYNCHRONOUS OSCILLATIONS

Having sub-synchronous oscillations will result in mechanical oscillations for the turbine-generator which can give mechanical damage or fatigue to the shaft. Also, other components can malfunction, or protection can be triggered. Therefore, it is important to eliminate the risk of sub-synchronous oscillations.

When studying sub-synchronous oscillations, it is important to take into consideration that the operating conditions influence the risk of oscillations. Having different components connected will give different characteristics to the grid and the operating condition of a nuclear power plant, such as load level and number of generators in operation, can influence the risk of oscillations.

Common definitions used for sub-synchronous oscillations are given in [7].

2.2.1 Sub-Synchronous Oscillations (SSO)

Definition given in [7]: ”Sub-Synchronous Oscillations (SSO) are the phenomena which concern electro-mechanical interactions, either between a turbine-generator and passive system elements such as series capacitors, or between a turbine generator and active system elements such as HVDC transmission system equipment control and static VAR system controls at frequencies below the nominal frequency of the system (i.e. < 50 Hz)”

As seen from the definition SSO includes several different objects for the oscillations and is therefore including both SSR and SSTI as described below.

2.2.2 Sub-synchronous resonance (SSR)

Definition given in [7]: "Sub-Synchronous Resonance (SSR) is the interaction between the mechanical/torsional masses in a generator (or squirrel-cage induction generator (SCIG) type wind turbine also known as type 1 wind turbine) and the electrical resonance from series compensation (capacitor) at frequencies below the nominal frequency of the system (i.e. < 50 Hz)."

SSR is specifically including series compensation and is therefore a part of the SSO cases. SSR is the traditionally studied SSO phenomenon [3] and can be divided into steady state SSR and transient SSR [8].

- **Steady state SSR** can be divided into induction generator effect (IGE) and torsional interaction effect (TI) [8].
  IGE is an electrical phenomenon typically caused by self-excitation and does not involve the mechanical system of the generator. If the rotor resistance is negative for sub synchronous currents and this negative resistance is larger than the positive resistance for the same frequency for the grid, oscillations can occur.
  TI includes energy exchange between the electric power system and the generator shaft. If the induced sub-synchronous torque in the generator is electrically close to one of the natural frequencies of the generator shaft generator rotor oscillations can occur. This will induce armature voltage components at both sub-synchronous and super-synchronous frequencies. The system will be self-excited if the resulting sub-synchronous torque is equals to or exceeds the inherent mechanical damping of the rotor.
- The **Transient SSR** phenomenon is called torque amplification (TA).
  TA results from oscillations caused by system disturbances. If these oscillations have a frequency corresponding to the frequency of a system with series compensated lines, large torques can be experienced.

2.2.3 Sub-synchronous torsional interaction (SSTI)

Definition given in [7]: "Sub-Synchronous Torsional Interaction (SSTI) is the interaction between the mechanical/torsional masses in a generator (or type 1 wind turbine) and a Power Electronic (PE) device (such as an HVDC link, SVC, wind turbine etc…) at frequencies below the nominal frequency of the system (i.e. < 50 Hz).”

2.2.4 Sub-synchronous control instability (SSCI)

Definition given in [7]: “Sub-Synchronous Control Instability (SSCI) is the adverse interaction between a PE device with other power object (such as Power Generating Module (PGMs), PE device or a series compensated system) at frequencies below the nominal frequency of the system (i.e. < 50 Hz).”

2.3 UNIT INTERFERENCE FACTOR

The Unit Interference Factor (UIF) is a parameter to assess the risk of torsional interaction between a generating unit or power plant and an HVDC converter. The UIF is a screening type of study to determine generating units with risk of torsional interaction that should be studied in more detail. The UIF is determined based on short-circuit calculations. The UIF_i for the i:th generator unit is defined according to [14]:

$$UIF_i = \frac{MVA_{HVDC}}{MVA_i}\left(1 - \frac{SC_i}{SC_{\mathrm{TOT}}}\right)^2 \tag{1}$$

where:

MVA_i	is the MVA for the i:th generator unit
SC_{TOT}	is the Short Circuit Capacity at the HVDC converter station with the i:th generator unit in operation
SC_i	is the Short Circuit Capacity (fault level) at the HVDC converter station with the i:th generator unit disconnected

A generating unit with an UIF less than about 0.1 will not have significant interaction with the HVDC converter and may be neglected in further studies. Synchronous generating units with an UIF larger than 0.1 has to be studied further to assess and investigate the risk for torsional interaction [14].

Historically, the UIF has been used to identify generating units that may suffer torsional interaction with respect to LCC (line commutated converter) HVDC system. With the development of VSC-HVDC the UIF screening method has also been applied to generating units nearby to VSC-HVDC system [15][16]. Using the UIF screening method is not applicable for systems with oscillations including series compensated lines since the calculation is based on having a synchronous generator and a VSC. However, it can be used to evaluate if there is a risk of SSO occurring between a synchronous generator and a VSC in a system where series compensation is present.

For multi-infeed HVDC system there are similar methods (Multiinfeed Interactive Effective Short Circuit Ratio, MIESCR) to evaluate the interaction between HVDC system [24]. The methods for multi-infeed HVDC systems are only valid for LCC HVDC system [25]. For this reason, they are not further mentioned here.

3 Study methods for analysing SSO

Sub-synchronous oscillations is a phenomenon that can occur between several different components in the power system. The traditional oscillations between a generator and a capacitor in a series compensated line is a quite straight forward system to study while VSC converters are more complex. There are several different study methods that have been used for evaluating the risk of SSO, and for SSO including VSC converters there is up to date no standard method to be used.

In this chapter, a review of the study methods used for analysing sub-synchronous oscillations (SSO) is made. Three different categories of study methods are evaluated: Analytical calculations, Frequency scanning and time domain simulations. These methods are described, and the characteristics of each method is evaluated.

3.1 ANALYTICAL CALCULATIONS

Using analytical calculations, a system that is characterized by ordinary differential equations can be analysed. Analytical calculations can be made either in the time domain or in the frequency domain, and these methods are suitable for limited systems since the complexity for larger systems is too high. To be able to use these methods, detailed knowledge is required about the system including all control loops.

From an academic perspective these methods give good insight into analysis of SSO and all data is known in detail. From an engineering perspective these methods may not be practical since detailed knowledge about the system and components may not be readily available for proprietary reasons. Moreover, the risk of SSR can be effectively assessed using frequency scanning techniques and electromagnetic transient simulation [28]. For these reasons, the methods using analytical calculations will only be briefly presented.

3.1.1 Time domain analysis

For time domain analysis the system is represented using ordinary differential equations (ODE) and may include a very detailed representation of the system (grid, turbine shaft, HVDC system, control laws etc). Generally, the system will be represented with non-linear ODE, which means that the system has to be linearized around an operating condition (non-linear tools will be overwhelmed to use). Then eigenvalue analysis may be used to investigate the dynamic properties of the system, which will show if there are any instabilities and in that case at which frequencies. The entire system needs to be modelled as one single state-space representation [29]. This will limit the size of the system that can be used since the calculations will be too complex for larger systems.

3.1.2 Frequency domain analysis

Frequency domain analysis is also based on linear system. This means that a non-linear system has to be linearized around an operating condition. In frequency domain analysis the system is represented using transfer functions representing the impedance or the admittance. Then Nyquist criteria, Bode diagram, passivity analysis or a combination may be used to investigate the dynamic properties of the system [31].

3.1.3 Passivity analysis

Passivity analysis can be applied to both a special kind of non-linear system and to linear systems. The convenience with passivity analysis is that any combination of subsystems represented in parallel form or in feedback form may be analysed individually. If all subsystems are passive, then the complete system is also passive. However, if any subsystem is non-passive it is not possible to say whether the complete system is unstable or not. In that case the Nyquist criteria may be used.

A strictly stable linear system, $h(s)$, is passive if and only if $\mathrm{Re}[h(j\omega)] \geq 0$ for all $\omega \geq 0$ [33]. As an example, one common way of modelling the VSC system (only considering the current control) is [30]:

$$i_{vsc} = G_{VSC}(s) i_{vsc}^{\mathrm{ref}} + Y_{VSC}(s) v \tag{2}$$

Where $G_{VSC}(s)$ is the current-control closed loop transfer function and $Y_{VSC}(s)$ is the VSC input admittance. Then it is sufficient to study $G_{VSC}(s)$ and $Y_{VSC}(s)$ independently to determine the stability. It is also possible to complement the system with additional and outer control loops.

Passivity analysis has recently been commonly used in the academics to analyze VSC system (HVDC and WTGs) with respect to SSO [30], [36] and [37].

3.2 FREQUENCY SCANNING (NUMERICAL)

For frequency scanning methods the frequency response of the system is determined for one frequency at a time. Here, the frequency scanning methods are numerical, i.e. the system response is determined from different types of test. This means that the detailed knowledge of all system components is not necessary. It is still essential that all relevant components and control laws are implemented in the model and that all settings are relevant, but the functionality does not have to be an open source. Instead, so called black-box models which only has an interface to the simulation model and proprietary code, or functionality may be hidden from the user may be used in some of the methods.

3.2.1 Complex torque method

The complex torque method is normally used for SSTI studies between generators and HVDC. The method is limited to study one generator at a time. In this method the electrical damping, or the transfer function from the speed input of the generator to the electrical torque output of the generator are calculated as shown in Figure 2.

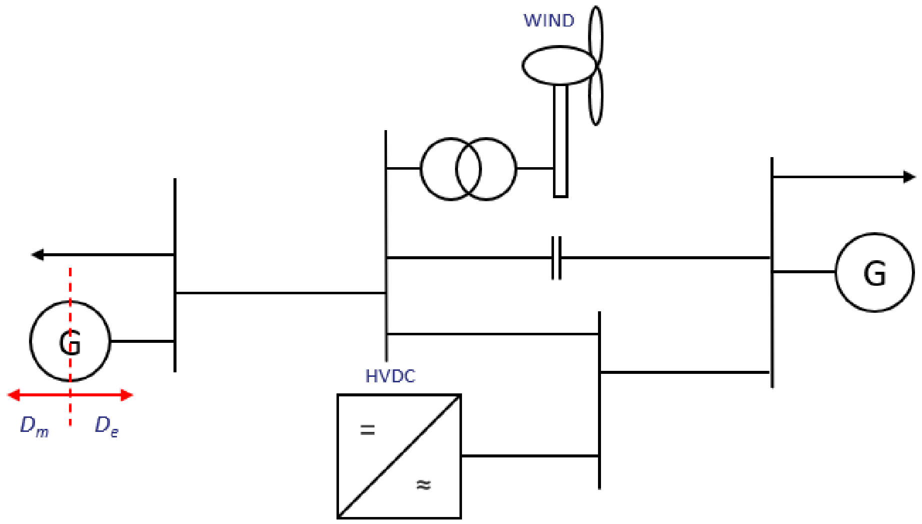

Figure 2 Study for the complex torque method

The electrical damping D_e for the generator includes the generator itself and the grid connected to the generator. If there is a large VSC converter located close to the generator, it can have a large influence on the electrical damping. Typically, the electrical damping can be calculated with and without the VSC converter connected to study the influence of the converter. The mechanical damping D_m only considers the mechanical system (turbine-generator shaft) of the studied generator and not the electrical system. In general, any device that controls or responds rapidly to power or speed variations in the sub-synchronous frequency range is a potential source for excitation of sub-synchronous oscillations and should be included in the study [39].

To calculate the electrical damping the input speed to the generator model is set to $\omega_0 + \Delta\omega$, where ω_0 corresponds to the synchronous frequency and $\Delta\omega$ is a sinusoidal speed perturbation. This can be done in an EMTP circuit simulation software, including the generator, HVDC and the connecting grid. The generator/turbine shaft can not to be included in the model since the speed is anyhow used as input for the method, i.e. any multi-mass model will be disabled. Other controller may however be included, such as the automatic voltage regulator (AVR) and power system stabilizer (PSS). The sinusoidal speed perturbation should be repeated for each frequency of interest and the generator electrical damping torque transfer function, $D_e(f_n)$, can be calculated as [4]

$$D_e(f_n) = \mathrm{Re}\left\{\frac{\Delta T_e}{\Delta\omega}\right\} \tag{3}$$

By Fourier analysis it is possible to determine the amplitude and phase of sub-synchronous torque and speed. The input speed to the generator model should be set according to:

$$\omega(t) = \omega_0 + \Delta\omega = \omega_0 + A\sin(\omega_m t) \tag{4}$$

The choice of the perturbation amplitude A should be chosen to be a small value to avoid the system responding with non-linear characteristics typically due to limitations. As a starting point the perturbation amplitude may be set to a few percent. Depending on the response of the system the amplitude may have to be adjusted.

If the shaft torsional modes of the turbine are at a frequency range where the generator experience positive electrical damping torque, the sub-synchronous oscillation will be damped. If the generator experience negative electrical damping torque at the shaft torsional modes, the mechanical damping torque of the turbine needs to be greater than the negative electrical damping torque or oscillations with growing amplitude will arise (sometimes this is also referred to as the positive net stability criterion). In many cases the damping torque of the turbine is not known and assumed to be zero (or close to). In case of low or negative damping, the HVDC should be equipped with damping controller to provide the necessary damping.

3.2.2 Impedance frequency scan

Frequency scanning analysis is used for sub-synchronous analysis in series compensated transmission system. The impedance frequency scan measures the impedance as seen from the generator's rotor for each generator of interest and includes the electrical system connected to the rotor. Generally, the method only considers the circuit parameters (R, L and C) of the system and not the dynamic response of control functions (such as in WTGs and HVDC systems). This is due to the built-in functions in the simulation software that just consider circuit parameters (e.g. R, L and C) in the frequency sweep and not user-written models and black-box models (neither including control functions from the standard PSCAD library). Therefore, load flow or RMS type programs (such as Harmonic Impedance in Power Factory) may be used to calculate the sub-synchronous impedance.

The impedance obtained by the frequency scanning method may then be used to assess [17]:

- IGE by studying the resistance at reactance crossover frequency (i.e. when the reactance changes from being inductive to capacitive or vice versa).
- TI by studying the total damping (electrical and mechanical) as shown below.
- TA by investigating reactance dip. For instance, if a reactance dip larger than 5% occurs within ±3 Hz at the complement modal frequency of the turbine there is a risk of oscillations [3] [17].

Torsional Interaction

This impedance, from the frequency scan, can then be used to estimate the electrical modal damping for torsional interaction (TI) between thermal power plants and series compensated overhead lines. Negative electrical modal damping has potentially the risk for SSR torsional interaction. For the generators where the turbine torsional data is available the electrical modal damping factor is compared to the mechanical modal damping factor. In many cases the synchronous generator may be modelled by its induction machine equivalent [4] [6]. The generator in simulation packages is typically implemented as a Norton Equivalent which means that the circuit parameters are not all modelled explicitly in the circuit matrix, only the Norton impedance. This is one reason for using the induction machine equivalent.

The electrical modal damping factor, σ_{en}, can be estimated as [6]:

$$\sigma_{en}(f_n) = -\frac{f_{sub}}{8H_n f_n}\left(\frac{R_{sub}}{R_{sub}^2 + X_{sub}^2}\right) + \frac{f_{sup}}{8H_n f_n}\left(\frac{R_{sup}}{R_{sup}^2 + X_{sup}^2}\right) \tag{5}$$

where

f_n	Torsional mode frequency for mode n
f_0	Synchronous frequency
$f_{sub} = f_0 - f_n$	Sub-synchronous frequency
$f_{sup} = f_0 + f_n$	Super-synchronous frequency
R_{sub}	Resistance at $f_0 - f_n$
X_{sub}	Reactance at $f_0 - f_n$
R_{sup}	Resistance at $f_0 + f_n$
X_{sup}	Reactance at $f_0 + f_n$
H_n	Modal inertia time constant for mode n

The net torsional modal damping for mode n, σ_n, can be found from:

$$\sigma_n = \sigma_{en} + \sigma_{mn} \tag{6}$$

where σ_{mn} is the turbine/generator mechanical modal damping factor. The electrical modal damping, D_e, and mechanical modal damping, D_m, relates to the modal damping factor as [4]:

$$D_n = D_e + D_m = 4H_n\sigma_{en} + 4H_n\sigma_{mn} \tag{7}$$

and the electrical modal damping, D_e, may then be expressed as:

$$D_e(f_n) = -\frac{f_{sub}}{2f_n}\left(\frac{R_{sub}}{R_{sub}^2 + X_{sub}^2}\right) + \frac{f_{sup}}{2f_n}\left(\frac{R_{sup}}{R_{sup}^2 + X_{sup}^2}\right) \tag{8}$$

3.2.3 Impedance/admittance scanning by dynamic simulations

In this method the impedance or admittance is determined by dynamic simulations and is implemented by sub-synchronous current (or voltage) injection. By using dynamic simulations, the method also includes all active components, such as wind farms and HVDC systems since they can be represented in the dynamic simulation model with all relevant control systems (as compared to the method in Section 3.2.2 which only considers the circuit parameters). Then by measuring the resulting sub-synchronous voltages and currents the impedance or admittance may be estimated. The simulation has to be repeated to estimate the impedance or admittance for all sub-synchronous frequencies of interest. For a grid just represented by circuit parameters this method will give the same result as the impedance frequency scan described above.

The illustration in Figure 3 shows the frequency scanning using current injection by a current source (depending on the layout of the investigated system a voltage injection using a voltage source may be used instead). In the figure a sub-synchronous current, I_{inj}, is injected (generally one sub-synchronous frequency at a time) at a bus where the sub-synchronous impedance or admittance should be determined or measured. The injected sub-synchronous current will cause a corresponding sub-synchronous voltage. By Fourier analysis it is possible to determine the amplitude and phase of sub-synchronous voltage and current. This corresponds to the method used in a previous Energiforsk report (SSR and DFIG) [10].

It is important to select the amplitude of the injected harmonics to a suitable level. It should give a response that is possible to measure with good accuracy but not affect the operation of the system. As an example, the injected harmonics should not cause any saturation in controllers or any other non-linear phenomena.

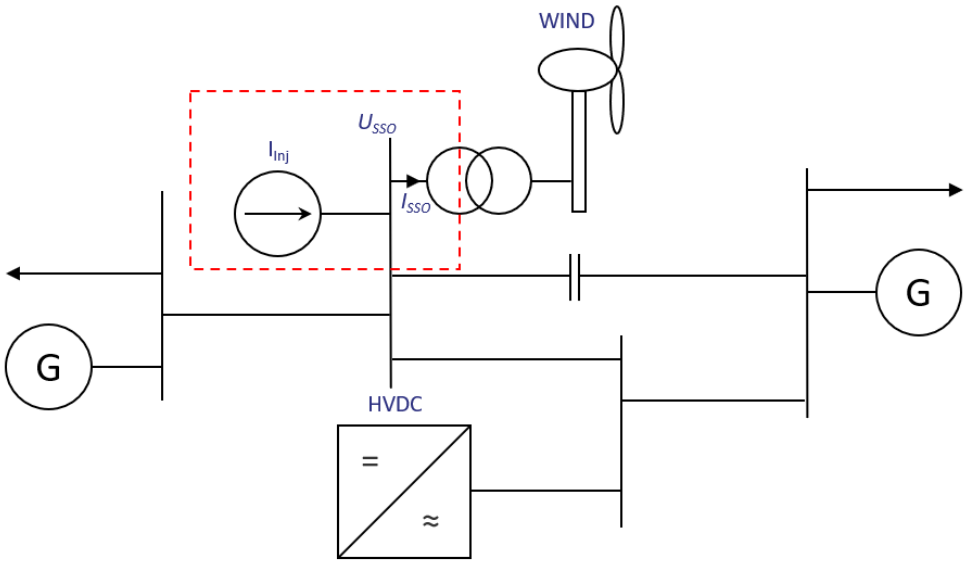

Figure 3 Frequency scanning by current injection.

In Figure 3 the sub-synchronous impedance is obtained for the wind park since the sub-synchronous current to the wind park and the resulting voltage are measured. Then the sub-synchronous impedance, Z, or admittance, Y, may be estimated from:

$$Z(j\omega) = \frac{1}{Y(j\omega)} = \frac{U_{SSO}(j\omega)}{I_{SSO}(j\omega)} \tag{9}$$

As an example, if the sub-synchronous reactance of the wind farm, in Figure 3, presents a zero-crossing this indicates that the wind farm presents a resonant condition at the zero-crossing frequency. If a matching resonant frequency exists in the transmission network, e.g. due to a series compensation, an SSO might be experienced. An unstable oscillation will be triggered if the sum of the equivalent resistance of the wind farm and the network resistance at the frequency of interest is smaller than zero (i.e. total negative resistance). The analysis is similar to the analysis of IGE, in Section 3.2.2.

It should be pointed out that the VSC converter's impedance or admittance becomes unsymmetric due to dc-link voltage control and phase-locked loop [40]. To represent the unsymmetric impedance or admittance it is useful to represent it as a matrix and not as a single complex-valued impedance, as in (9). Recent research has shown how to model the impedance or admittance of a VSC accounting for the unsymmetric characteristics [36][41][42][43]. In synchronous coordinates (dq-system), this may be represented as:

$$\begin{bmatrix} u_d \\ u_q \end{bmatrix} = \begin{bmatrix} Z_{dd} & Z_{dq} \\ Z_{qd} & Z_{qq} \end{bmatrix} \begin{bmatrix} i_d \\ i_q \end{bmatrix} \tag{10}$$

Then each transfer function in the impedance matrix needs to be identified.

Depending on the location of sub-synchronous current and voltage measurement the sub-synchronous impedance or admittance may be determined for different components or parts of the grid. Moreover, the frequency scanning has to be repeated for different operating conditions to account for non-linearities and other conditions that may have significant influence on the impedance. The amount of frequency scanning required for a specific study is difficult to stipulate (recommendations in the literature has not been found, at least by the authors) and has to be decided case-by-case depending on the discovered variations in impedance/admittance and the scope of the study.

3.3 TIME DOMAIN SIMULATIONS

In principle, it is possible to study all types of sub-synchronous oscillations by dynamic simulation in an electromagnetic transient program (EMTP). The simulation model in the EMTP software may be very detailed and include all relevant components and control loops. Moreover, there are no restrictions in modelling non-linear components.

Time domain simulation is particularly suited for TA, since the effect of TA occurs about 1 s following the initiating transient (such as a short circuit) [6]. The other types of SSO may results in a slowly growing oscillations requiring a long simulation time. Moreover, it may be difficult to set up the correct conditions for SSO and also the perturbation to initiate the oscillation (e.g. the method in Section 3.2.3 may be seen as a time domain simulation with sub-synchronous current injection as perturbation). Perturbation may be faults, connection or disconnection of components, change of reference values etc.

Time domain simulation is a great (maybe also necessary) complement to the methods in Section 3.1 and 3.2. The methods in these sections provides information of potential resonance frequencies and conditions, generally with a linearized model. Time domain simulations with a full-order non-linear model can then typically be used for validation purposes and to investigate or quantify the SSO response in the time domain.

3.4 COMPARISON OF THE STUDY METHODS FOR ANALYSING SSO

Here, a comparison of the different study methods is made based on the information in this chapter. In chapter 5, the implementation of the study methods is made on a generic test system and this will result in a summary of the study methods made in the discussion in chapter 6.

3.4.1 Properties of the different study methods

When comparing different study methods, the following factors are important:

- **Non-linear**: The study method can handle non-linear models of components in the system.
- **Black-box:** The study method can handle black-box models.
- **Includes controls**: The study methods can include controls (typically converter control or turbine governor).
- **Investigate subsystems**: it is possible to investigate one subsystem at a time and find out if the total system is stable.
- **Time efficient**: The study method is time efficient.

The study methods described in this chapter are evaluated for the above-mentioned criteria in Table 1.

Table 1 Comparison of limitations

	Non-linear	Black-box	Includes controls	Investigate subsystem	TIme efficient
Analytical – Time Domain			X		
Analytical – Frequency Domain			X	X	
Complex torque method		X	X		
Impedance frequency scan					X
Impedance/admittance scanning by dynamic simulations		X	X	X	
Time domain simulations	X	X	X		

Looking at the analytical methods, an analytical representation of all components included in the study is needed. Therefore, non-linear models have to be linearized and no black-box models can be included in the study. Also, these methods require complex calculations and can just handle smaller systems. For the frequency domain method, the system can be divided into subsystems that can be handled separately, which is not the case for the time domain methods.

The complex torque method uses an EMTP simulation program and can handle both black-box models and control systems. The whole electrical system is considered seen from the studied synchronous generator and therefore subsystems cannot be handled separately. Therefore, the VSC converter itself cannot be studied. Instead, the grid can be studied with and without the VSC to conclude if the VSC increases or decreases the electrical damping.

The impedance frequency scan shows the sub-synchronous impedance using the built-in frequency sweep in an EMTP software or harmonic impedance scan if available in RMS tools (such as in Power Factory). Consequently, no black-box models or control systems are considered using this method. This method is time efficient since it uses the built-in frequency scan in the simulation software.

The impedance/admittance scanning by dynamic simulations uses an EMTP software and calculate the impedance for each sub-synchronous frequency based on a time domain simulation for that frequency. This method will thereby include both black-box models and control functions. It is much more time consuming than the impedance frequency scan but will include more components. Since it is a numerical method, the scanning has to be performed several times to investigate the contribution from different equipment and operating conditions.

Time domain simulations are used to simulate the actual occurrence of sub-synchronous oscillations and will in addition to black-box models and control systems also include non-linear functions. However, it should be noted that time domain simulations are used to evaluate a certain event and not to characterize the system.

One drawback with the EMTP models is that normally only a smaller part of the grid can be included. The reason for this is that EMTP software requires a small time step and a too large grid may lead to unreasonable simulation times. Moreover, to model a very large system will require a tremendous effort. For this reason, only a smaller part can be represented as one-to-one and the rest of the grid needs to be represented as an equivalent grid. The grid represented as one-to-one needs to include all parts and equipment that contributes to the sub-synchronous oscillations. Ideally the border between the one-to-one representation and the equivalent grid should be chosen so that the equivalent grid, in the sub-synchronous range, can be approximated as Thevenin equivalents, i.e. voltage sources and impedances. Power system RMS-type simulation packages, such as PSS/E and Power Factory, has built-in functions to develop grid equivalents. Note that if RMS type programs assumes fundamental impedances during simulation, they may not be suitable for frequency scanning using dynamic simulations.

3.4.2 Proposed study methods

Looking at the characteristics of the different simulation methods described above, the suitability of using the study methods for different systems of interest are shown in Table 2. Note that for system including VSCs there are different methods proposed depending on if the models are known or if a black-box model is given.

Table 2 Comparison of use

	SG – Seris compen	VSC - SG	VSC-VSC	VSC – SG Black-box	VSC-VSC Black-box
Analytical – Time Domain	X	X	X		
Analytical – Frequency Domain		X	X		
Complex torque method	X*	X		X	
Impedance frequency scan	X				
Impedance/admittance scanning by dynamic simulations	X*	X*	X	X*	X
Time domain simulations	X	X	X	X	X

X* means that the method can be used but there are other more time-efficient or more suitable methods available.

For the traditional SSR between a synchronous generator and a series compensation all parameters are known, and the analytical time domain method can be used as well as the impedance frequency scan. Also, the complex torque method and frequency scanning by dynamic simulations can be used but are less time efficient.

For the systems with VSC-SG as well as VSC-VSC the analytical time domain method can be used if the detailed model of the VSCs including the control are known. For a system consisting of several VSCs with known parameters the analytical frequency domain method can be suitable since it can handle one converter at a time. For these methods, the impedance frequency scan cannot be used since they include control functions.

If black-box models are given for any of the VSC converters or if a larger system should be studied, the analytical functions are not suitable. In that case the system with synchronous generator and a VSC can be studied using the complex torque method, which works both with and without black-box models.

For the system with two VSC converters, the complex torque method cannot be used since there is no synchronous generator included. In that case the impedance/admittance scanning by dynamic simulations is a suitable method both with and without black-box models.

Time domain simulations are suitable for verification in case of all systems.

Consequently, since models of the VSCs are usually given as black-box models for commercial products, the recommended method for a system with a synchronous generator and a VSC is the complex torque method that will indicate risk of SSO. The impedance/admittance scanning by dynamic simulations can be used to study a part of the system in more detail, for example see how parameter variations affect the sub-synchronous impedance of a VSC since the complex torque method does not give the detailed characteristics of the VSC separately.

4 Description of converters for HVDC and wind power

The amount of power electronics in the power system is increasing, and there is also a trend to connect large components with power electronics. With these large installations, such as VSC-HVDC transmission and wind farms, the converters can also have a large impact on the power system compared to smaller installations. Consequently, there is also a risk for these components to be a part of sub-synchronous oscillations.

In this chapter, a qualitative description is made for the differences between wind power converters and VSC-HVDC links with regards to their contribution to sub-synchronous oscillation modes. For VSC-HVDC converters, possible topologies are shown, and the design of the control is discussed. For the FPC wind farms, the physical construction is shown, and the design of the control is discussed both for a single wind turbine and the park control.

4.1 VSC CONVERTERS

The voltage source converter (VSC) converts between AC and DC circuits. The VSC consist of forced commutated valves and can operate independently of the AC grid (in contrast to thyristor converters). Figure 4 shows an example of two VSCs connected back-to-back. This means that the DC-side of both VSC are connected to each other through a DC-link capacitor. The DC-link capacitor is required as short-time energy storage to maintain the DC-link voltage (approximately) constant [11].

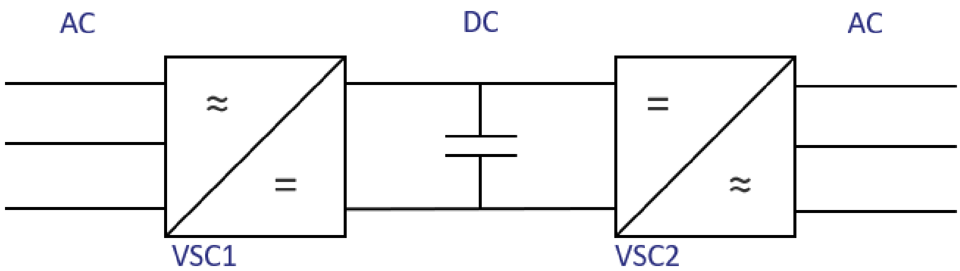

Figure 4 Two VSC connected back-to-back.

Both HVDC systems and wind power converters have the same principle as the back-to-back VSC converter shown in Figure 4. For an HVDC transmission the two converters, VSC1 and VSC2, correspond to the two converters in each end of the transmission link and the DC link includes the DC cable or OH (overhead)-line instead of just a capacitor. For a wind turbine converter, one of the VSCs is connected to the wind turbine generator and the other converter is connected to the grid. The rated power differs depending on the application, a single HVDC converter can have a rated power up to just below 1000 MW and a DC voltage of 500 kV. A converter in a wind turbine handles the power of a single turbine, typically 2 MW but also up to 10 MW for offshore applications.

The VSC has two degrees of freedom, which means that it is possible to control two variables independently from each other. For a grid connected VSC this could be, for instance, active and reactive power and for VSC connected to a generator this could be, for instance, torque and flux.

One common way to control the VSC is to use space vectors, i.e. the three-phase system (zero-sequence is ignored) has been reduced to an equivalent two-phase system which then can be represented as a complex quantity. It is possible to transform the space vector to a synchronous coordinate system or *dq* coordinates. The synchronous coordinate system must be aligned with a quantity, normally the flux of a machine or the grid voltage. Space vectors in synchronous coordinates will be DC quantities in the steady state. There are also other methods to control the VSC such as direct torque control (DTC) and direct power control (DPC), for instance used in a large manufacturer's wind turbine converters [38].

VSCs are typically used in variable-speed drives, wind turbines, HVDC systems, STATCOMs (static synchronous compensator) and uninterruptible power supplies. VSC converters can have different topologies, where the most common topologies are the two-level converter and the multi-level converter.

4.1.1 Two-level converters

The two-level converter is the most common VSC for voltages up to 1800 V and is presented in Figure 5.

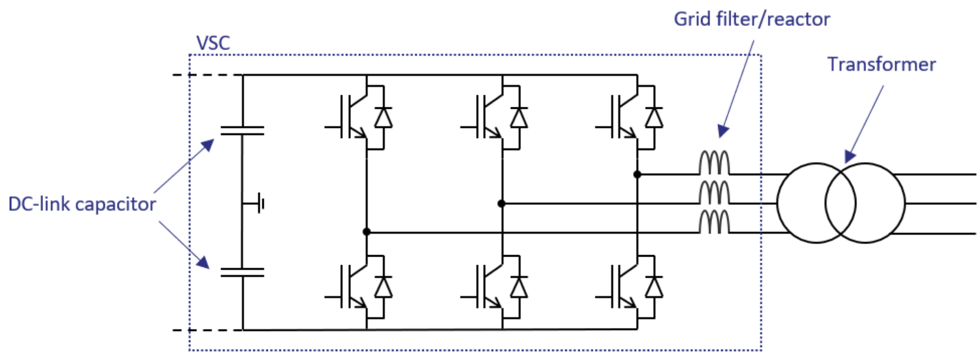

Figure 5 Two-level VSC.

In the two-level converter each phase leg consists of two series connected semiconductor valves. These semiconductor valves can consist of different devices, from a single Mosfet (metal oxide semiconductor field effect transistor) for smaller converters to many series connected IGBT (insulated gate bipolar transistor) modules for HVDC converters. The AC terminals are formed in the middle of the phase leg. To maintain the current fairly constant during the switching of the phase legs, an inductor is connected in series with the AC-terminals. This inductor can either be a separate physical device, as for a grid connected converter with phase reactors, or indirectly as the inductance in a transformer or an electric machine [11].

Grounding for the converter can be made in two ways, either by grounding the DC-link as shown in Figure 5 or by grounding the neutral of a Y-connected converter transformer.

In addition to the AC-side filter/reactor shown in Figure 5 there can also be filters tuned for special harmonics if needed [20].

The two-level converter is usually controlled using pulse-width modulation (PWM) as seen in Figure 6.

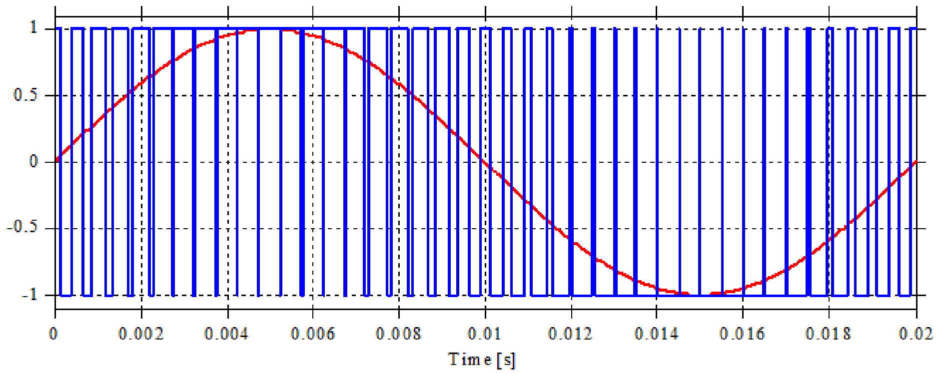

Figure 6 PWM switching pattern for a two-level converter.

The principle of PWM operation is to form the switching pattern for the upper and lower semiconductor valves in the phase leg so the average value of the voltage at the AC terminal is the same as the reference value of the AC voltage. Note that the switching frequency in Figure 6 is very low for illustration purpose. The switching frequency for a two-level converter is generally above 1 kHz, and considerably higher for smaller converters. For details about the operation of a phase leg refer to [11].

The two-level VSC is an economical solution to low power ratings and low voltages but have drawbacks for higher voltages. As seen in Figure 6 there are large harmonics in the AC-voltage at the switching frequency and multiples of the switching frequency. As the voltage rating of the converter increases semiconductor devises with higher voltage ratings are used which also have larger switching losses. Therefore, large converters tend to have lower switching frequency and thereby also lower order harmonics. Even though there are semiconductor devices with a couple of kilovolts blocking voltage a grid connected converter must have many semiconductor devices connected in series [11].

To improve the characteristics for large converters there are several different options for multilevel converters such as three-level, five-level and seven-level converters. In these converters, there are several DC-link capacitors resulting in that several DC levels can be created inside the converter. As an example, the three-level converter can give the voltage levels 1, 0 and -1 as output compared to 1 and -1 for the two-level converter. The resulting AC arm voltage for a three-level converter can be seen in Figure 7.

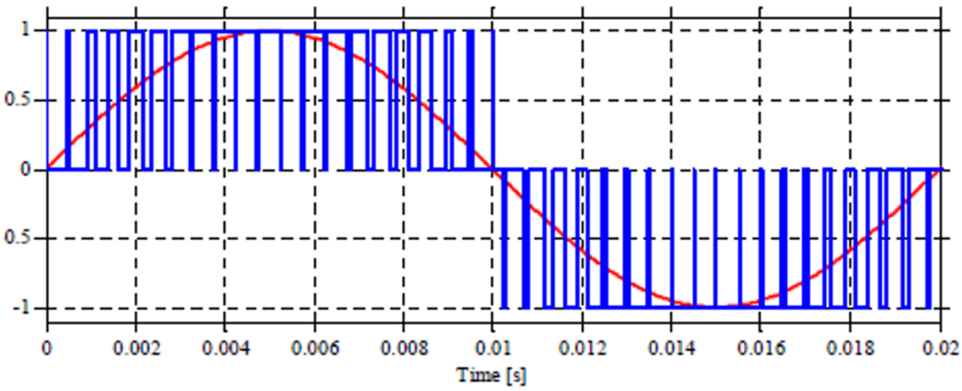

Figure 7 PWM switching pattern for a three-level converter.

The multi-level converters have been used extensively for medium voltage applications. However, since it is not convenient to extend the levels above a few, series connection of semiconductor devices is needed for converters connected to the transmission system. [11]

4.1.2 Modular multi-level converters

As discussed in the previous section, the two-level converter is a convenient solution for smaller converters. However, with an increasing power and voltage rating the drawbacks with the two-level converter are more significant. This can be avoided using multilevel converters for medium voltages as mentioned above, but these topologies are not suitable for high voltage converters. To improve the performance of the converter at transmission voltage, cascaded multilevel converters are introduced.

A cascaded multilevel converter is based on series connected converter elements, submodules, which each contain semiconductor valves and DC capacitors. In Figure 8 a modular multi-level converter (MMC) is shown, which is a cascaded multilevel converter and the topology used in HVDC applications.

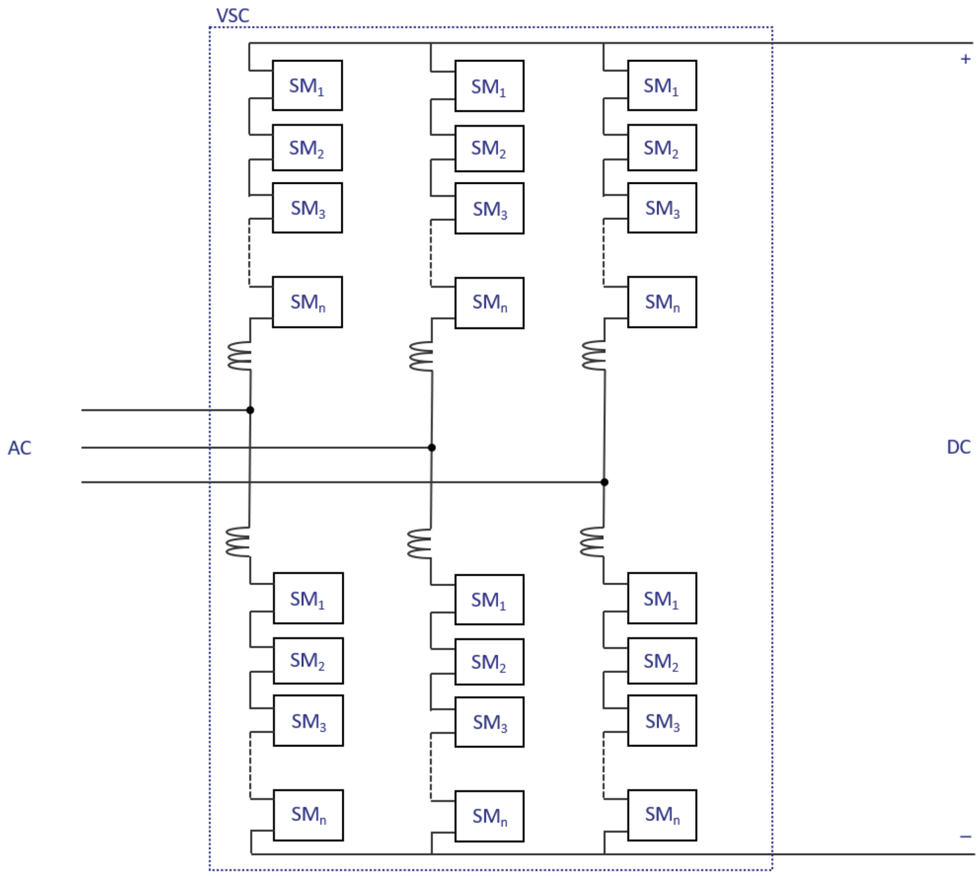

Figure 8 Modular multi-level VSC.

Figure 9 shows the two most common types of submodules (SM), i.e. the full bridge and the half bridge.

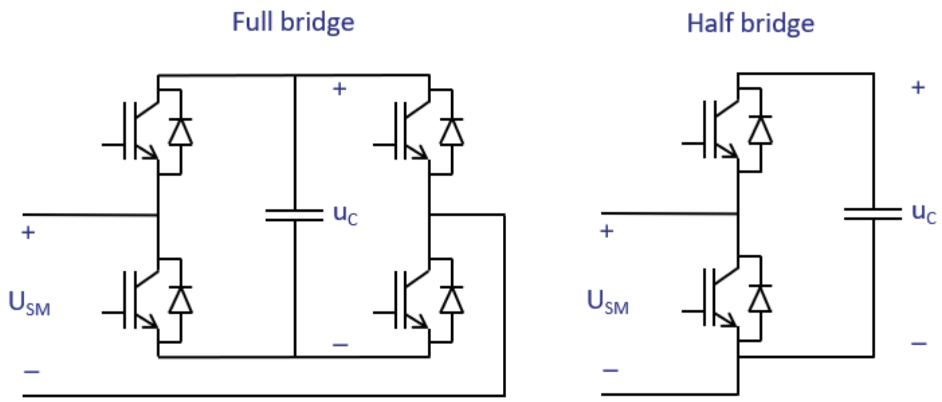

Figure 9 Common types of SM.

The full bridge SM may produce three voltage levels, 0 V and ± u_c V, while the half bridge may produce two voltage levels, 0 V and + u_c V [11]. The capacitor in the submodule has to be large enough to maintain a relatively constant voltage while carrying a significant current during the fundamental period. For HVDC systems the half bridge is the most common type of submodule since the full bridge SM is more expensive.

As seen in Figure 8 the submodules are connected in series forming a submodule string. The submodules are controlled in order to form an AC-voltage that corresponds to the reference voltage as seen in Figure 10.

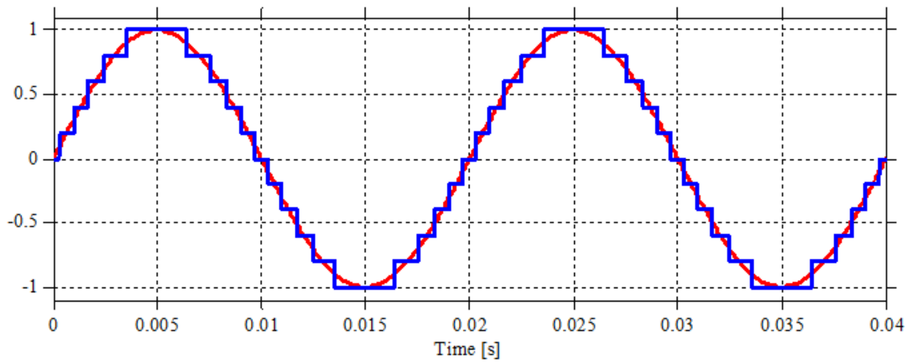

Figure 10 Arm voltage for the Modular Multilevel converter.

It can be seen that the submodules are switched one at a time to follow the reference value of the AC voltage. Note that Figure 10 uses just a few submodules for illustration purpose, in MMC converters for HVDC applications the number of submodules is significantly larger and the arm voltage is very similar to the reference value. Each submodule is just switched with the fundamental frequency and the switching losses are thereby very low. Also, the AC voltage is very close to a sinusoidal waveform and the harmonics will be low, reducing the need for AC side filters. On the other hand, the capacitance in each submodule must be large and the switching must be done carefully to maintain balance between the voltage in each submodule. This is shown in detail in [11].

In the same way as for the two-level converter, grounding for the converter can be made either by grounding the DC-link as shown in Figure 5 or by grounding the neutral of a Y-connected winding in the converter transformer.

Since the multi-level converter has less harmonics due to the switching pattern there is also less need for AC-side filters.

4.1.3 Control of grid connected VSC

In the sections above, different converter topologies have been shown. These topologies are different, but they all have the aim of producing AC-voltages as close to given reference voltages as possible.

For a VSC, the aim is to transmit active and reactive power between AC and DC, and it can control the active power and reactive power independently. An example of the overall control strategy for a VSC can be seen in Figure 11.

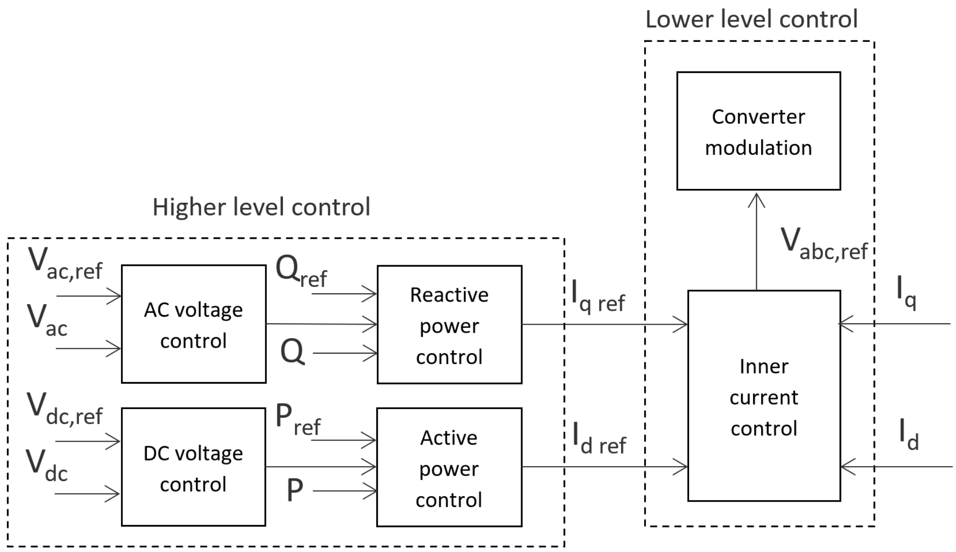

Figure 11 Overall control principle for the VSC control.

The input to the VSC control is the reference values for the active power, P_{ref}, and the reference value for the reactive power, Q_{ref}. The origin of the references varies depending on the application of the converter. For a grid connected converter, the reactive power reference is typically either set to a constant value or a result of a voltage control to support the grid. The active power reference can also either be set to a constant value or be a result of a DC-link voltage control or a frequency control for the AC grid. There are also several different examples of controllers for the active and reactive power, such as grid forming converters or virtual synchronous machines. The controllers resulting in the reference currents is called higher level control [11].

The inner current controller will then calculate the voltages needed to obtain the required currents. These voltages are then the input to the converter modulation where the semiconductor components are controlled to make the phase voltages follow the given reference voltages. The inner current controller and the converter modulation form the lower level control. Comparing different converter topologies, it is the converter modulation that is different for the topologies, the other controls are designed due to the application.

When controlling a VSC, vector control is commonly used. When using vector control the three-phase system is reduced to a two-phase system with α and β that are phase shifted 90°. These α and β vectors can then be projected to a coordinate system that rotates with the fundamental frequency, called the synchronous coordinates or the dq-frame. The dq-coordinates are illustrated in Figure 12.

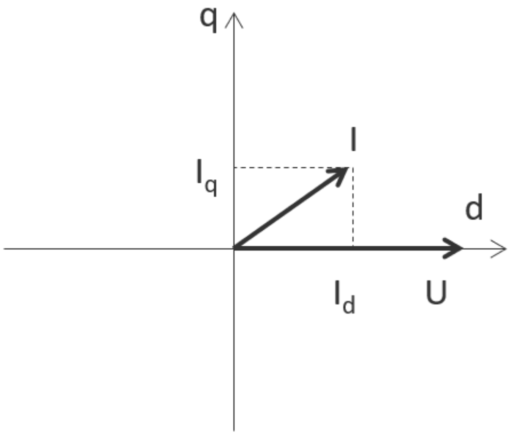

Figure 12 Illustration of the dq-frame.

In Figure 12 the synchronous coordinates are aligned with the voltage. As a result, the current in d-direction, I_d, gives the active power and the current in q-direction, I_q, gives the reactive power. For a converter controlling a machine, the d-direction can instead be aligned with the flux in the machine. The reference value for I_d and I_q are inputs to the inner current controller as seen in Figure 13.

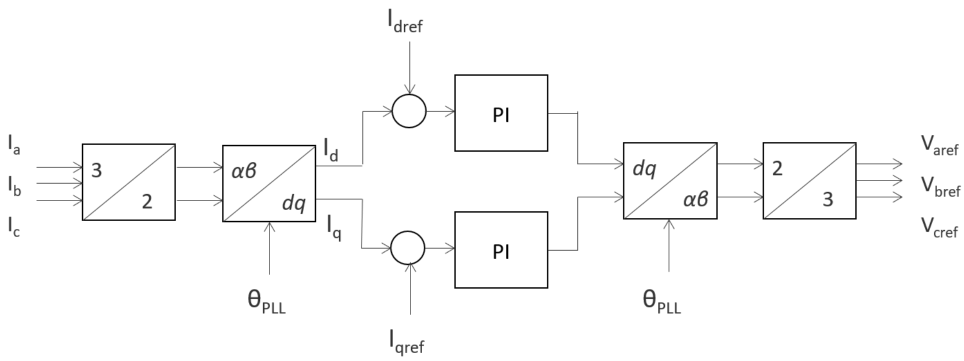

Figure 13 Inner current controller.

For the inner current controller, the reference values for I_d and I_q are compared to the measured values. To achieve the measured values of I_d and I_q, the phase currents are measured and first transformed to the αβ frame and then to the synchronous coordinates d and q. This transformation is shown in detail in [11].

When transforming to the synchronous coordinates, a phase locked loop (PLL) is needed to identify the angle of the voltage that is used in the transformation to and from synchronous coordinates. The resulting angle Θ_{PLL} is used as an input in the inner current controller. For details about the PLL refer to [11].

When having the measured values of I_d and I_q these are compared to the reference value and the resulting deviation is used as an input to the PI-controllers giving reference values for the voltages V_d and V_q in synchronous coordinates. These voltages are transformed to the αβ frame and then to three phase system giving the reference voltages V_{aref}, V_{bref} and V_{vcref} which are the outputs of the inner current control as shown in Figure 11 and Figure 13.

These references for the AC-voltages are then the input to the converter modulation. This modulation was shown in the sections above, in Figure 6 for the two-level converter, in Figure 7 for the three-level converter and in Figure 10 for the modular multilevel converter. Looking at the overall control strategy in Figure 11 it should be noted that the deviation in the control for the different topologies of VSC is in the converters modulation, the other parts of the control is the same for the different topologies.

Looking at the overall control structure in Figure 11 there is a cascaded controller with different layers:

- Higher level control: Calculates the reference values of the currents, can be active and reactive power control, voltage control or frequency control.
- Inner current controller: Calculates the reference values for the arm-voltages, included in the lower-level control.
- Converter modulation: Calculates the switching patterns for the arm voltages to follow the reference values, included in the lower-level control.

To have a stable controller the inner control loops must be significantly faster than the outer control loops. An indicative illustration of control bandwidths can be seen in Figure 14.

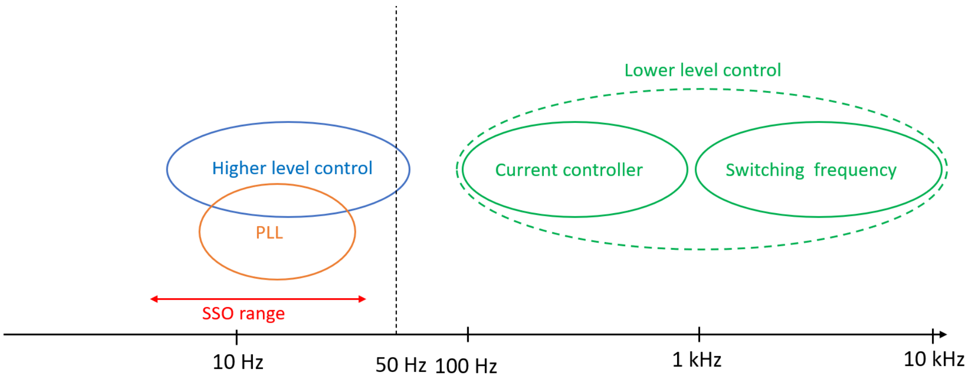

Figure 14 Bandwidths of the controllers in a converter controller.

For a grid connected VSC the switching frequency is generally above 1 kHz [36] and higher for smaller converters. The bandwidth of the inner current controller should then be less than one fifth of the switching frequency. The higher level controller including the voltage controllers should then have a bandwidth well below the bandwidth of the current controller, a common factor is that the current controller is ten times faster than the voltage controller [32] [36]. The phase locked loop (PLL) should track the frequency of the voltage and the bandwidth should be chosen below the fundamental frequency and much lower than the inner current controller [36].

Looking at the bandwidths for the controllers in Figure 14 it can be seen that the controllers with possible interaction with sub-synchronous oscillations are the phase locked loop and the higher level controllers. Note that also grid forming converters or virtual synchronous machines have special deigns of the higher level controls in the frequency range indicated in Figure 14. Also, in [36], the design of the outer voltage controller and the PLL are considered for SSO. The converter modulation, which is different for different converter topologies, has the bandwidth of the switching frequency. Thereby, the higher-level control of the converter is affecting the risk of SSO, but not the chosen topology since the lower-level control is at higher frequencies.

For grid connected converters, there are often grid supporting control functions that can affect the reference values of the active and reactive power. These are described for the wind power converters and the HVDC converters respectively in the coming sections.

4.2 WIND POWER CONVERTERS

For the FPC (full power converter) wind farms, the physical construction for the wind farm is shown as well as the topology of the wind turbine converters. The design of the control is discussed both for a single wind turbine and the park control.

4.2.1 Wind park layout

In a wind farm, there are several wind turbines connected to a local collection grid acting as a generating unit towards the grid. A principal layout of a wind park can be seen in Figure 15 [20].

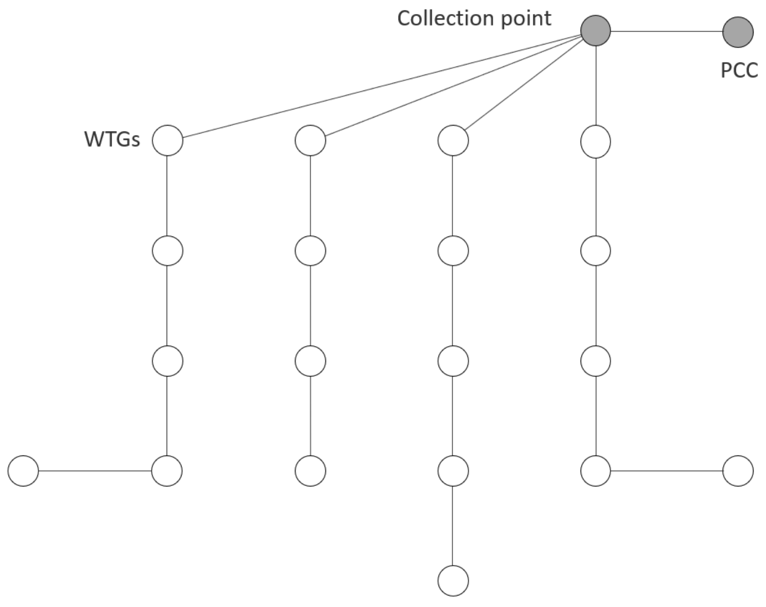

Figure 15 Typical layout of a wind park.

The wind turbine generators (WTGs) in the wind park are located in a favourable way according to wind conditions and other limiting factors. There are several different ways of connecting the WTGs in the collection grid, in the example in Figure 15 the WTGs are connected in four radials that are connected to the collection point in the wind park. From this collection point there is a connection to the point of common coupling (PCC), which is the interface between the grid and the wind park.

Looking further into the electrical system for the wind park, the main components from the WTG to the grid connection can be seen in Figure 16 [20][21]. The wind turbine is a full-converter turbine also called type 4 wind turbine [22].

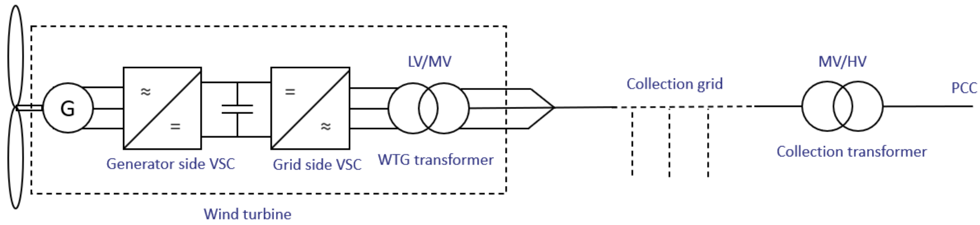

Figure 16 Electrical main components for a wind park.

In a wind farm with a full-power converter the wind turbine generator is connected through a back-to-back VSC. In this converter there is a generator side converter controlling the generator and a grid side converter controlling the DC-link voltage and the reactive power towards the grid. The output voltage from the generator varies between different WTG designs, in the example in Figure 16 there is low voltage output from the generator and also the grid side converter, typically 690 V. This voltage is increased to the medium voltage level for the collection grid in the WTG transformer. The output from each WTG is then connected to a radial of the collection grid as shown in Figure 15. All radials are collected in the collection point and connected to the collection transformer. The collection transformer handles the power of the whole wind park and increase the voltage level to the voltage level of the point of common connection (PCC).

Seen from the transmission system, there are typically two transformers between the connection point of the wind park and the WTG converter, the WTG transformer and the collection transformer.

4.2.2 Converter topology

The full power converter in the wind turbine is a back-to-back VSC as shown in Figure 16. In Figure 17 the wind turbine converter is shown in more detailed implemented as a two-level VSC converter.

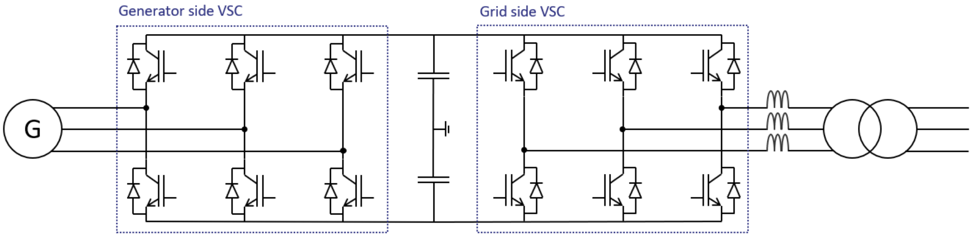

Figure 17 Wind turbine with full-power converter.

The topology of the wind turbine converter can vary between different turbines. In [11] it is stated that the two-level converter is by far the most commonly used topology for all applications with DC side voltages up to 1800 V, which is the case for the common WTG generators with 690 V output voltage.

In [26] it is stated that the two-level topology can suffer from high losses for wind turbines with higher power rating. Also, the cabling at voltage levels below 1 kV is a challenge for high power levels. As a solution it is stated that there is common for wind turbines with a power higher than 3 MW to have multicell converter configurations, where for example two two-level VSCs are connected in parallel to cope with the high power. There is development ongoing for the converter technology for higher voltage and power where the multilevel converter is a possible choice, such as the three-level converter [26]. This topology can for example be used in wind turbine converters for 3.3 kV generators with the rating 4-12 MW [13]. There are several additional options for future use in wind turbines shown in [26].

4.2.3 VSC control for wind turbine

The main task of the generator-side VSC is, of course, to control the generator. In many cases this is done by having an inner fast field-oriented current control loop that controls the generator current. Then outer slower control loops, acting on the current references, may be added to control the flux and the torque or speed of the generator. The aim of the control is to obtain the required operating point for the generator which either can be the optimum speed of the wind turbine to achieve as much power as possible at the present wind speed [21][26] or to obtain a certain power setpoint for the converter.

The main objective of the grid-side VSC is to control the dc-link voltage. The control of the grid-side VSC consists in many cases of a fast inner current control loop, which controls the grid current, and outer slower control loops that controls the dc-link voltage and the reactive power as shown in Figure 11. The reactive power for the grid-side converter is controlled to follow the reference value given by the park controller.

4.2.4 Park control

With the increased share of wind power in the grid, the requirements for wind generation has also increased. In the requirements for connection of generators [18], the requirements are specified for power generating units based on their rated power, which could be a single large synchronous generator as well as a wind park including a large number of wind turbines.

Structure of the wind park controller

Since the wind park is acting as a single generating unit towards the grid, there is a park control that coordinates the active and reactive power towards the grid. This park control calculates total reference values for the active and reactive power and then distributes these reference values to the turbines [19]. An overview of the control structure of a wind park can be seen in Figure 18.

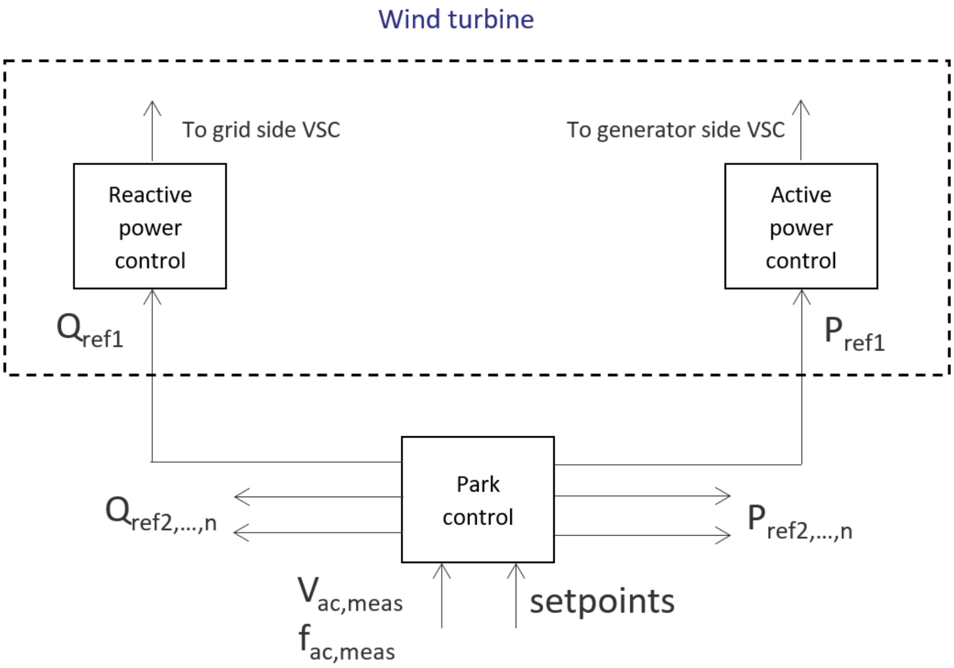

Figure 18 Overall control principle for wind park control.

The park control is the interface towards the grid and is controlling the active and reactive power in the PCC according to the requested operation. The input to the park control can be setpoints for the active and reactive power and there can also be settings for voltage control and frequency control. The park control can also contain ancillary services such as frequency support, inertial response and power oscillation damping [19]. Since the park control is a control loop outside the converter control in each turbine and requires communication to the turbines, the time constants for the controllers are slower. In [19] response times for the controllers in the range of a few hundred milliseconds to a second is mentioned. Therefore, the park control is considered to be slow and the possible contribution to sub-synchronous oscillations is at quite low frequencies.

The outputs from the park control are reference values of the active power and the reactive power to each wind turbine in the park. In the wind turbine note that the reactive power can be handled separately for the grid side converter and the generator side converter and the reference value for the reactive power is given to the grid side converter. For the active power reference, the value from the park controller is the input to the generator side converter while the grid side converter controls the DC-link voltage.

Grid code requirements

There are many requirements for each generating unit. However, the requirements to be considered in this study are the requirements affecting the control of the generator, i.e. requirements that affect the reference values of active and reactive power for the wind park. Since a wind park is considered as a generation unit new installations should follow the European Commission Regulation 2016/631 [18] and also the Swedish regulation EIFS 2018:2 [34] and the Finnish regulation VJV2018 [45].

Frequency control

The generation unit should be able to provide active power variation, ΔP, depending on the frequency variation, Δf, with a given droop, s, and frequency threshold, Δf_1, as follows:

$$\frac{|\Delta P|}{P_{ref}} s = 100 \frac{|\Delta f| - |\Delta f_1|}{f_n}$$

The value of the active power reference value P_{ref} for a power generating unit that is not synchronous is defined as the present active power at the moment of the disturbance.

The time for the power response should be agreed with the grid owner.

For a power generating unit that is not synchronous, the grid owner can demand synthetic inertia during very fast frequency variations. The characteristics and control principle of the synthetic inertia as well as the parameters should be given by the grid owner [18].

Reactive power

The grid owner should be able to assign a required capability for reactive power.

The power generating unit should be able to produce reactive power according to control of the voltage, the reactive power or the power factor. For a step change the time for the control to reach 90 % of its final value should be given by the grid owner and is within the range 1-5 s [18].

Other controls

Power generating units that are not synchronous should be applied with power system stabilizers (PSS), that should damp oscillations in the range 0.25-1 Hz according to the Swedish requirements [34]. For the requirements in Finland, it is stated that the impact of the controller on the dynamics of the power system should be taken into control. Simulations should be made to study electromechanical oscillations related to angle stability at frequencies 0.2 – 2 Hz [45].

4.2.5 SSO mitigation functions

For grid connected converters, there is extensive research ongoing considering frequency response of grid-connected converters [1][2] [32][37]. From the frequency response the system can be studied to see how the controller design and settings affect the stability of the system, i.e. if there is a risk for SSO to occur [32].

To avoid SSO, the operation of the converter at critical frequencies is considered with the aim to have positive electrical damping (the converter dissipating energy) at these frequencies [36] [37]. To improve the electrical damping the control of the converter, outer voltage control and the PLL, can be adjusted or active damping can be added [32] [37].

Another example to improve the controller is to have a dual current controller for the positive and negative sequence as shown in [20]. This controller uses two rotating reference frames, the positive sequence reference frame and the negative sequence reference frame. These are used to control the positive sequence current and the negative sequence current respectively. The advantage of this current controller is that it has infinite gain at the fundamental positive and negative sequence current and high gain at other frequencies. In [20] this is stated to be favourable to avoid SSCI between full power converter wind turbines and series compensated lines.

Note that for a wind farm, both the control in each wind turbine and the control for the park have a risk of contributing to SSO. The PLL is typically located in each turbine while the AC voltage control is in the park controller. This makes SSO mitigation more complex compared to an HVDC converter where a sub-synchronous damping controller is commonly used if needed.

4.3 HVDC CONVERTERS

For the HVDC transmission systems, different configurations and topologies are shown, and the control of the converters is discussed.

4.3.1 Topology

A grid connected HVDC converter has a similar topology compared to a back-to back VSC converter, with the difference that there is a DC transmission cable or OH-line for the DC link. The converter is connected to the transmission system via a converter transformer.

Each converter can be either a two-level converter or a multilevel converter as seen in section 4.1. The first VSC HVDC system was based on two-level converters and were relatively small systems. Today, all new VSC HVDC transmission systems are based on MMC.

An HVDC transmission system can be configured in several different ways as shown below [12].

A symmetric monopole has one VSC converter in each end with symmetric voltages as shown in Figure 19.

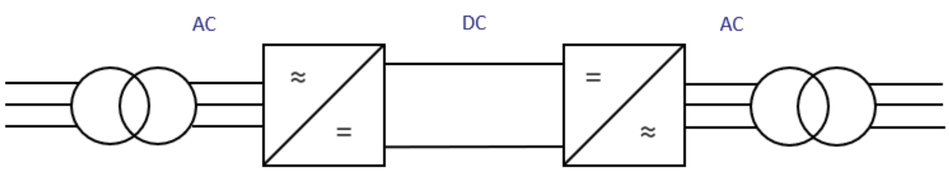

Figure 19 Symmetric monopole HVDC transmission.

With this configuration the voltage Vdc between the poles is distributed to $+V_{dc}/2$ on one pole and $-V_{dc}/2$ on the other pole.

One alternative to the symmetric monopole is to have an asymmetric monopole where one pole is grounded. This can be made either with a metallic return as shown in Figure 20 or with a ground return as shown in Figure 21.

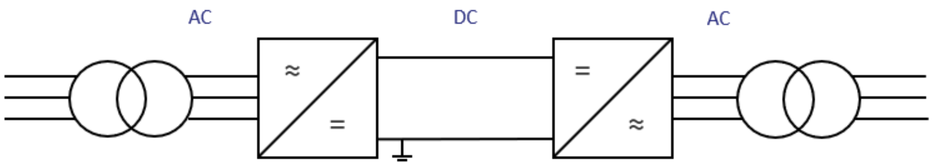

Figure 20 Asymmetric monopole HVDC transmission with metallic return.

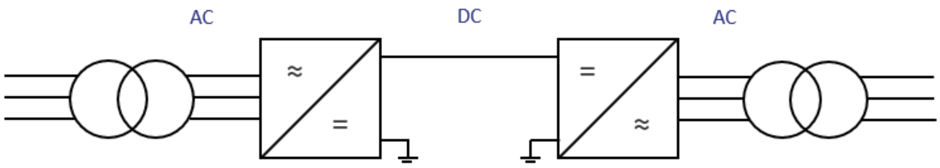

Figure 21 Asymmetric monopole HVDC transmission with ground return.

For the asymmetric system, one pole has the voltage V_{dc} and the other pole is grounded.

There is also an option of having two converters in series resulting in a bipolar converter as seen in Figure 22.

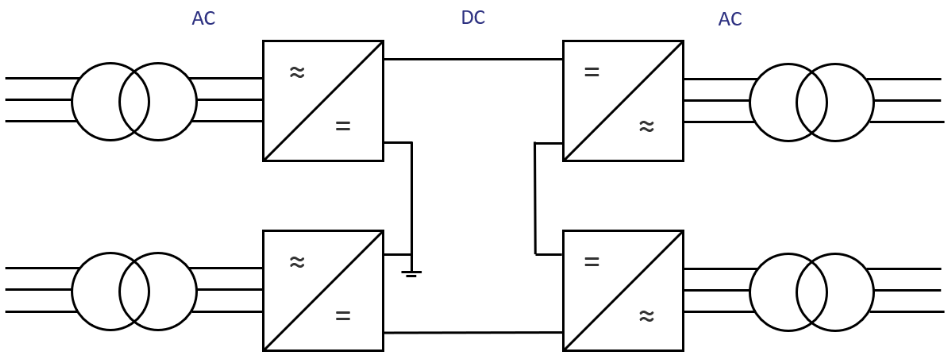

Figure 22 Bipolar HVDC transmission.

For the bipolar converter, one pole has the voltage $+V_{dc}$ and the other pole has the voltage $-V_{dc}$. The larger HVDC transmission systems are usually bipolar systems, where one converter is rated half of the power of the bipolar transmission system.

There is also the possibility to have a multiterminal HVDC system with three or more terminals. There is extensive research ongoing at the moment on these systems, but they are not included in this report.

4.3.2 Control of HVDC transmission system

The HVDC system is used to transmit large amounts of power over long distances, it can be a connection between two asynchronous systems, transmission within a power system or connection to remote generation such as offshore wind power.

For HVDC transmission there are general requirements in a similar way as for generating units given in the European Commission Regulation 2016/1447 [35].

Since the HVDC system is a large unit in the transmission system there are usually also specifications on the operation given by the grid operator.

Active power [35]

The grid owner gives the maximum time within which the HVDC link should be able to control its active power after receiving the setpoint.

The responsible for the HVDC system should show how the active power should change in case of disturbance in one or several of the connecting AC grids. This change should be started within 10 ms. Reversing the power from full power in one direction to full power in the other direction should be possible as fast as it is technically possible, and should not take more than 2 s.

If the grid owner requires, the HVDC system should be able to give synthetic inertia as a response to fast frequency variations. The principle for this control system should be agreed with the grid owner as well as the parameters.

The HVDC system should be able to control the frequency in the connected AC grids independently. The principle for this control system should be agreed with the grid owner as well as the parameters.

Reactive power [35]

The HVDC system should be able operate in the following control modes; voltage control, reactive power control and power factor control.

For a step in the voltage reference, 90 % of the final value should be reached within a time agreed with the grid owner within 0.1- 10 s.

Additional control modes can be agreed with the grid owner.

Other control functions [35]

When several converter stations or other equipment are electrically close the grid owner can require an investigation of possible negative interaction. If there is a negative interaction, investigations should be made to reduce the risk and thereby fulfil the requirements [35].

The HVDC system should be able to contribute to damping of power oscillations in the connected AC grids. The control system for the HVDC may not decrease the damping of power oscillations. The grid owner should give a frequency range where the control actively should damp the oscillations in the grid and make the necessary investigations. The grid owner and the owner of the HVDC system should together agree on parameters for this control [35].

For sub-synchronous torsional interaction (SSTI), the HVDC system should contribute to electrical damping of the torsional frequencies. The grid owner should provide necessary information and the SSTI studies should be performed by the HVDC owner. The studies should identify possible conditions where SSTI exists and give suggestions on actions to reduce the risks [35].

Also, additional control features for the HVDC link can be specified by the system operator such as emergency power control, black-start and other protection schemes.

4.3.3 VSC control

The control of an HVDC VSC is done in the same way as the general control shown in Figure 11. There are outer active/reactive power controls that give references to the inner current control. From the inner current control, the voltage references are given to the converter modulation (converter firing control) [12].

For a two-terminal HVDC system, one converter is operating with active power control and one converter is operating with DC-voltage control. The reactive power is controlled independently for the converter.

For a multi-terminal HVDC system, it is stated in [12] that one converter should operate in DC voltage control mode and the other converters should operate with active power control. It should be noted that it can be additional control functions present in case of multiterminal systems such as droop control of the DC voltage.

4.3.4 SSO mitigation functions

For an HVDC converter, it is stated that the system should contribute to electrical damping of the torsional frequencies [35]. In literature, it is a general approach to VSC converters to adjust the control parameters to achieve positive electric damping for the torsional frequencies [32] [37].

For HVDC, a sub-synchronous damping controller (SSDC) is traditionally used for damping of SSO instead of adjusting the control parameters [28]. In the SSDC controller, a damping is added for each torsional frequency. A band-pass filter will obtain the oscillations at each torsional frequency. To these oscillations a gain and a phase shift is added, and the resulting damping is added to the reference currents in the controller [28].

4.4 COMPARISON OF CONVERTERS CHARACTERISTICS

4.4.1 Comparison of physical construction

The difference in the physical construction of the HVDC converters compared to the wind power converters is mainly due to the size of the converters.

- The wind turbine converter is connected to the medium voltage collection grid via a turbine transformer and the whole wind part is connected to the high voltage transmission system via a collection transformer.
- The HVDC converter is a single grid connected converter with high power (up to 1000 MW) and output voltage connected to the transmission grid via one converter transformer. The wind power VSC converters are smaller converters with lower power (2-10 MW) and lower output voltage.

The topology of the converter also depends on the voltage and power of the converters.

- For the relatively small wind turbine converters common topologies are the two-level converter and the three-level converter, however there is ongoing research on new possible topologies. Due to the power rating two parallel converters can be used to reduce the current rating.
- For the larger HVDC converter the modular multi-level converter is the topology generally used on the recently installed HVDC systems. In the early VSC HVDC systems the two-level converter was used.

It should be noted that the difference in topology mainly affects the converter modulation that is in a frequency range considerably higher than the studied sub-synchronous oscillations.

4.4.2 Comparison of controller design

Looking at the controllers there are different regulations for wind power, that is defined as a generating unit, and an HVDC transmission system. There are general requirements, such as frequency control and AC voltage control, that are similar but the HVDC system has more specifications for additional controllers. As an example, the HVDC system should have power oscillation damping and also damping of sub-synchronous torsional interaction (SSTI) if needed. For the wind turbine a park controller is used to make the wind turbines operate as a single generating unit towards the grid. This control is relatively slow and can affect sub-synchronous oscillations in the lower frequency range. Also, a wind farm is required to have a power oscillation damping.

The controllers for the converters are implemented by the manufacturers and are generally not public information. However, the common control strategies for the converters are similar independent of the power and voltage rating of the converters and the topology used. It has also been found that there are the higher level control that handles frequency control, AC voltage control etc., as well as the PLL that have similar bandwidths as the sub-synchronous oscillations. For the wind park controller, the bandwidths of the controllers are limited by the delay in the communication between the park controller and the wind turbine. Therefore, if the sub-synchronous oscillations are caused by the controller in the wind turbine, the damping of the oscillations also must be implemented in the wind turbine controller. However, it should be noted that there are also controllers in the park controller, such as for example AC voltage controller that can cause oscillations is the lower frequency range.

4.4.3 Comparison of SSO mitigation

Comparing the SSO mitigation it can theoretically be made in the same way for HVDC systems and wind power converters. However, for HVDC systems damping of SSO, mostly referred to as SSTI, is general practice and stated in regulations and specifications. This is traditionally made using a SSDC (sub-synchronous damping controller) that will damp oscillations at the present torsional frequencies. For wind turbine converters damping of SSO is still in the research stage where proposed methods are to increase the electrical damping either by adjusting the control structure/parameters or to add a damping controller.

5 Conditions for sub-synchronous oscillations

For obtaining amplified sub-synchronous oscillations, certain criteria have to be fulfilled. The components, in this case a synchronous generator and a voltage source converter, have to oscillate against each other at a frequency where the damping is low.

In this chapter, a generic test system is used to illustrate different factors that affect the risk of sub-synchronous oscillations in the system. This is made by using the evaluation methods described in this report and thereby the implementation of the methods is shown.

5.1 GENERIC SYSTEM USED FOR STUDIES

For studying the principle of SSO a generic test system is used. The two main components in the model are the synchronous generator and the converter as seen in Figure 23.

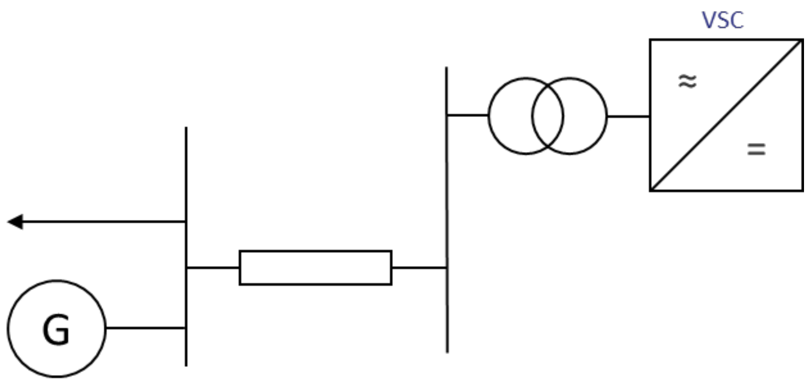

Figure 23 Generic test system.

In the model, there is also an impedance between the generator and the VSC transformer as well as an equivalent grid model connected to the generator bus.

The system voltage is 415 kV and the short circuit power at the generator bus from the grid equivalent is 5490 MVA and the short circuit power at the HVDC bus from the grid equivalent is 5350 MVA. The rated power of the HVDC link is 1000 MW and the generator is rated 600 MVA.

The system is modelled in PSCAD.

5.1.1 Generator model

The generator model is a generic model of a 600 MVA synchronous generator, with known torsional modes around 16 Hz and 28 Hz, based on the standard synchronous generator model using default parameters is PSCAD including a multi-mass model for the turbine string. The generator transformer is rated 650 MVA and a leakage reactance of 10 %. To characterize the generator model, a frequency sweep is made for the generator and the generator transformer and the resulting sub-synchronous impedance is plotted in Figure 24.

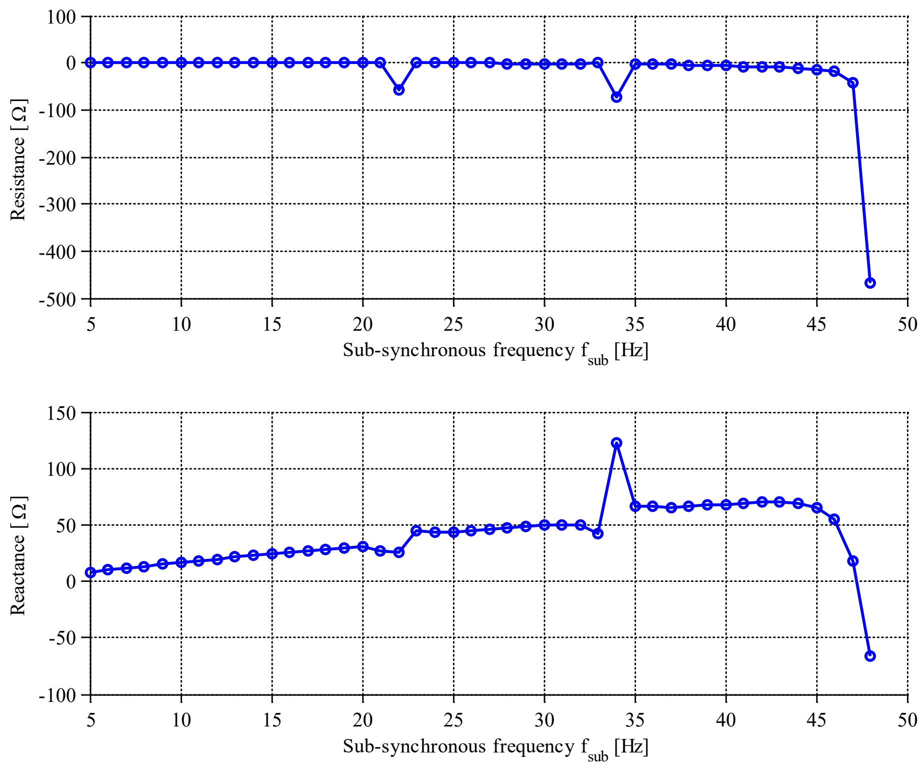

Figure 24 Frequency scan of the impedance for the generic generator model.

Having the torsional mode frequencies f_n at 16 Hz and 28 Hz might result in sub-synchronous frequencies at f_0-f_n. This gives the possible sub-synchronous frequencies 50 - 16 = 34 Hz and 50 - 28 = 22 Hz which also are the frequencies identified for the generator model in Figure 24.

5.1.2 Converter model

The VSC converter is modelled as a generic converter that either can be seen as an aggregated model of several wind turbine converters or a single HVDC converter. The VSC is connected to the grid via a single transformer (600 MVA and a leakage reactance of 10 %) as is the case for the HVDC converter. This is used as a starting point in order to have a system that is as simple as possible.

The converter model is based on controllable voltage sources and therefore the modulation is not included. The modelling and control of the converters are following what is outlined in [11].

The control of the converter is as described in section 4.1.3, see Figure 11 and Figure 13, including inner current control loop as well as outer control of the active and the reactive power. There is also a phase locked loop (PLL) that gives the angle as input to the inner current controller. The converter can either be operated as inverter or rectifier depending on the direction of the power flow and can either be controlling the active power according to a fixed reference value or controlling the voltage for the DC link.

For a wind turbine converter, the grid side converter will operate as inverter and control the DC link voltage. For an HVDC link, one of the converters is controlling the DC link voltage while the other converter will have a fixed reference value for the active power (or operated in frequency control mode).

As seen in section 4.1.3 the controllers that have bandwidths in the SSO range are the PLL and the active/reactive power controls.

In the generic test system, the converter is set to control the active power and the AC voltage.

5.2 EVALUATION OF THE RISK OF SSO

Knowing the mechanical torsional modes of the turbine-generator set, the connected system should be evaluated regarding the electrical damping at the torsional frequencies.

5.2.1 Complex torque method

Using the complex torque method, described in section 3.2.1, the electrical damping is simulated as seen from the rotor of the generator for the generic test system. For comparison, the electrical damping is also obtained for the case with the converter valves replaced by voltage sources. The resulting electrical damping for both cases for different torsional mode frequencies are shown in Figure 25.

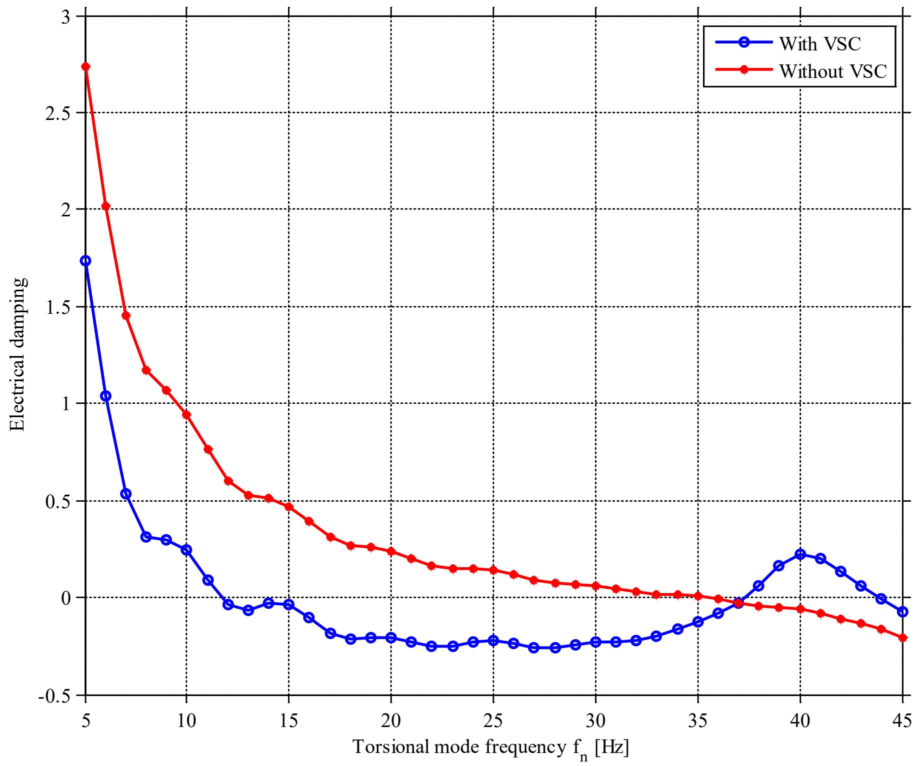

Figure 25 Electrical damping for the test system, with and without VSC.

In the figure, it can be seen that the VSC will give negative damping at frequencies between 12 Hz and 37 Hz. It is also obvious that the damping is decreased by the VSC compared to the system without the VSC present. The synchronous generator behaves as an induction machine equivalent for sub-synchronous frequencies and will therefore have a negative resistance below 50 Hz (e.g. negative slip). When approaching a torsional frequency of 50 Hz the negative resistance has an increasing value giving a total negative electrical damping.

Comparing the electrical damping to the characteristics of the generator, it can be seen that the electrical damping is negative at the frequencies where the generator has torsional modes, at frequencies f_n = 16 Hz and f_n = 28 Hz. Therefore, there is a risk for oscillations in the system. Looking at the torsional mode frequencies, the electrical damping is lower at 28 Hz than at 16 Hz and therefore indicates at a higher risk of oscillations at 28 Hz. However, this also depends on the mechanical damping for the torsional modes, which is not usually known to any detail.

Note that when performing a study of the electrical damping, it is important that the operating condition for the system is realistic and that the variation in the speed for the rotor does not result in any non-linearities in the controllers.

5.2.2 Impedance scanning by dynamic simulations

The sub-synchronous impedance was measured for the VSC at the generator side of the line connecting the generator and the VSC as shown in Figure 23.

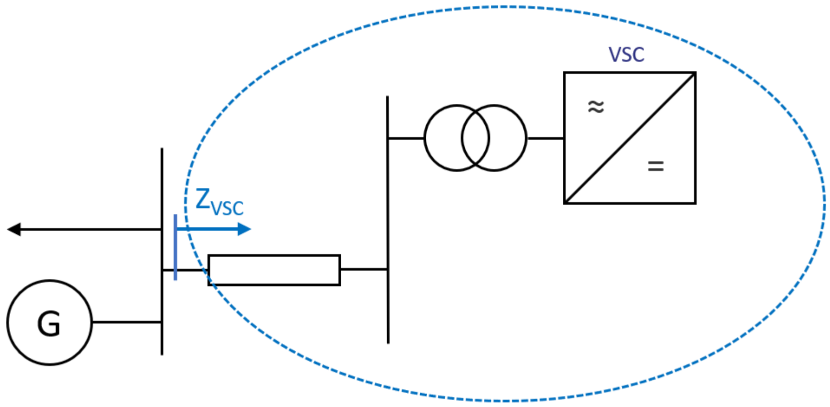

Figure 26 Frequency impedance measurement for the VSC.

The measurements are made as show in [10] and the method is described in Section 3.2.3. In this example the single-valued complex impedance is studied and any unsymmetric impedances, as mentioned in Section 3.2.3, is not considered here in this simplified example. The resulting resistance and reactance, as a function of the sub-synchronous frequency, are shown in Figure 27.

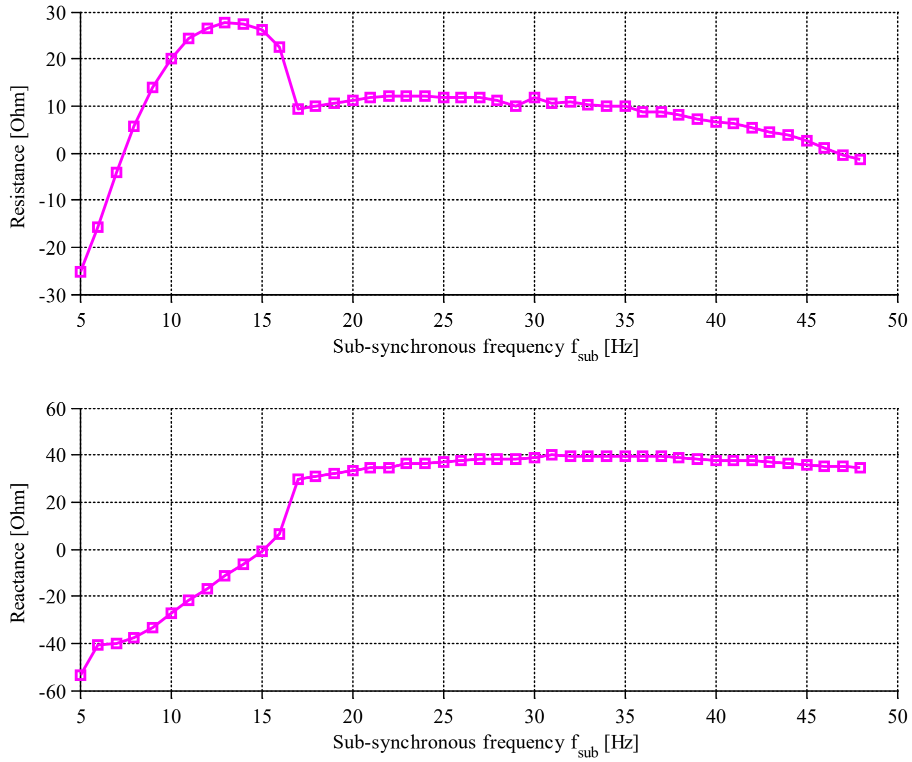

Figure 27 Sub-synchronous impedance for the VSC.

For the sub-synchronous frequencies, f_{sub}, corresponding to the torsional modes, 50 - 16 = 34 Hz and 50 - 28 = 22 Hz, the harmonic impedance is quite constant. Both the sub-synchronous resistance and the sub-synchronous reactance are positive.

The impedance at sub-synchronous frequencies will be used when comparing the characteristics of the VSC when for example changing the controller.

5.2.3 Time domain simulations

From the results using the complex torque method and the impedance scanning, there is an indication for a risk of sub-synchronous oscillations. Therefore, a time domain simulation has been made with the generic test system shown in Figure 23 and also a system where the VSC converter is replaced with a voltage source.

The resulting rotational speed, voltage, active power and reactive power are shown in Figure 28 for the complete test system and in Figure 29 for the case with the VSC replaced by a voltage source. The measurements for the generator are made at the low-voltage side of the generator transformer and the measurements for the VSC (or the equivalent voltage source) is made at the high voltage side of the VSC transformer.

At 16 s, a fault with a duration of 50 ms is made at the high voltage side of the generator transformer in order to trigger the oscillations.

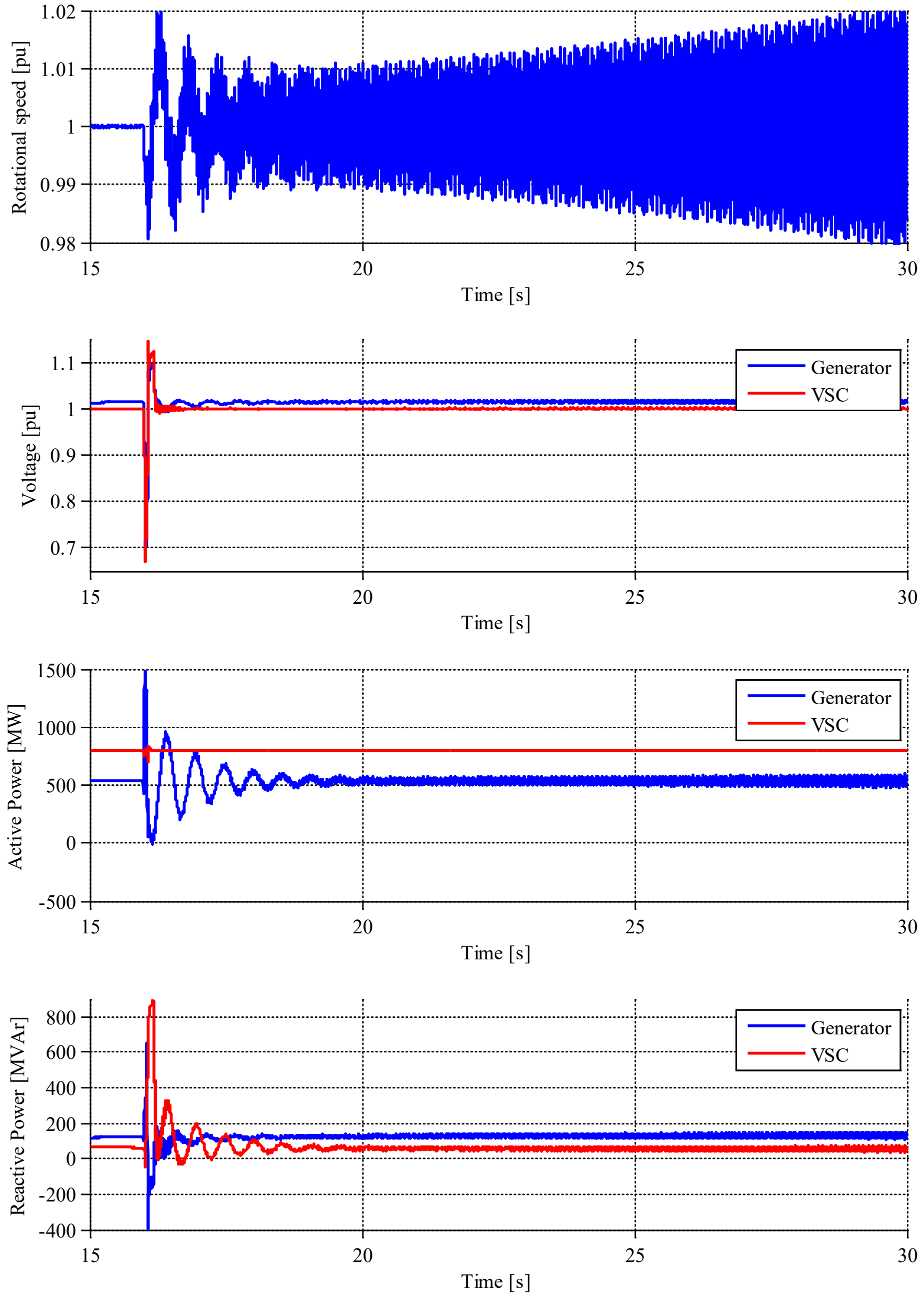

Figure 28 Time domain simulations for the generic test system.

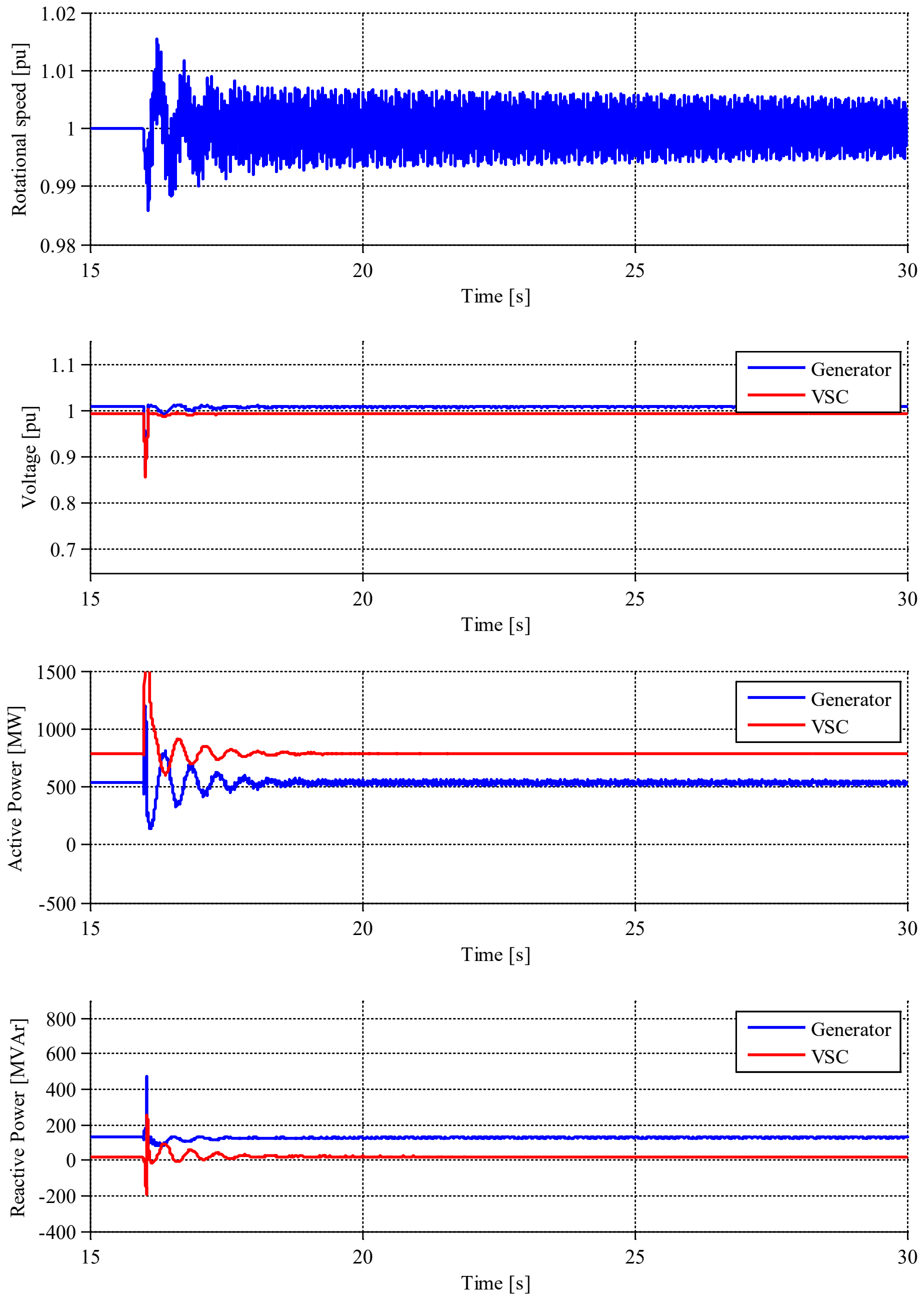

Figure 29 Time domain simulations for the generic test system with the VSC replaced by a voltage source.

Comparing the results, the initial transients at about 2 Hz following the fault are of similar magnitude for both cases. However, the oscillations at higher frequency (but still below 50 Hz) are damped slowly for the case without the VSC and are increasing in magnitude for the case with the VSC. This shows that the control of the VSC results in an amplification of the sub-synchronous oscillations.

These oscillations are shown in more detail in Figure 30 and Figure 31.

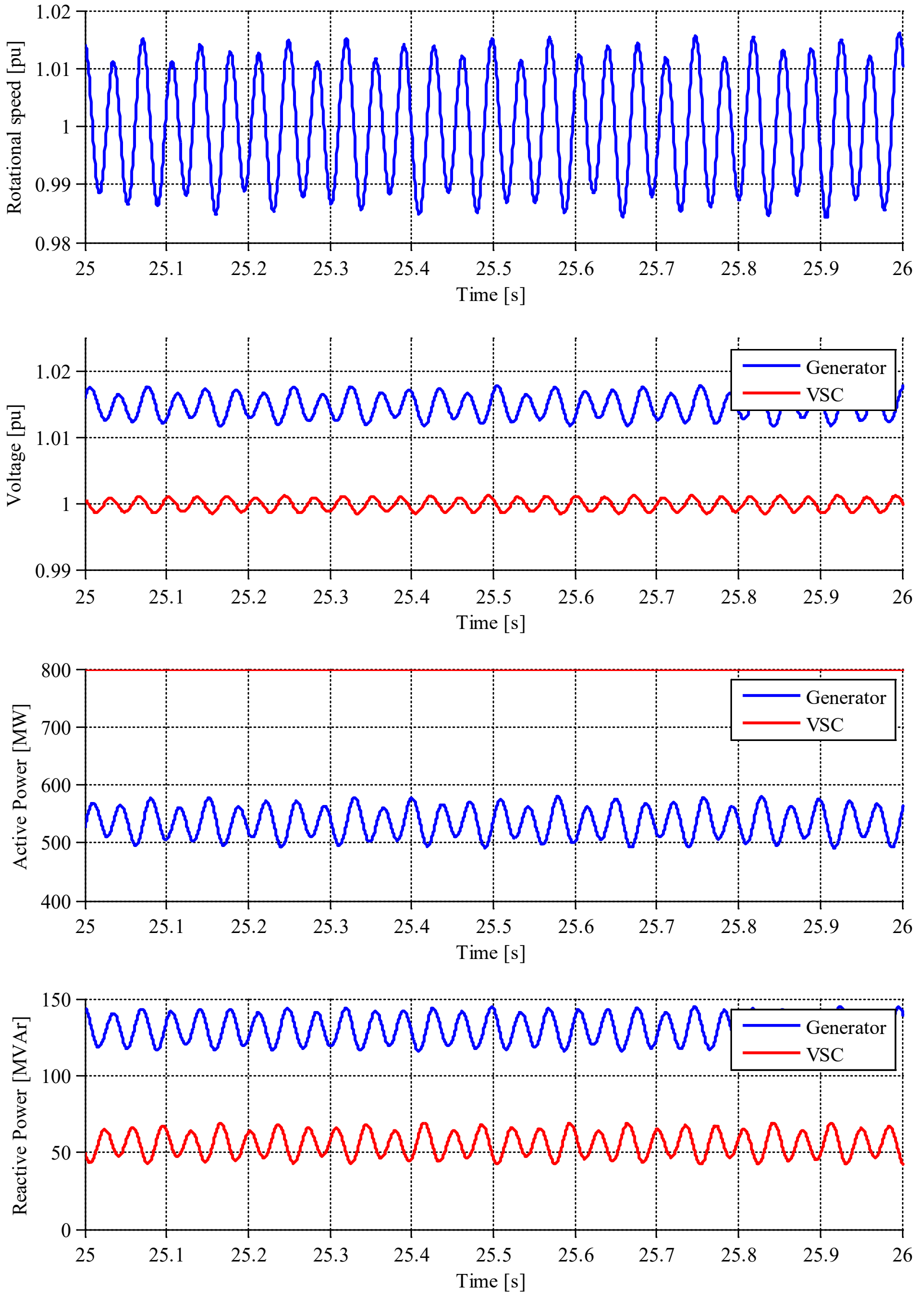

Figure 30 Time domain simulations for the generic test system.

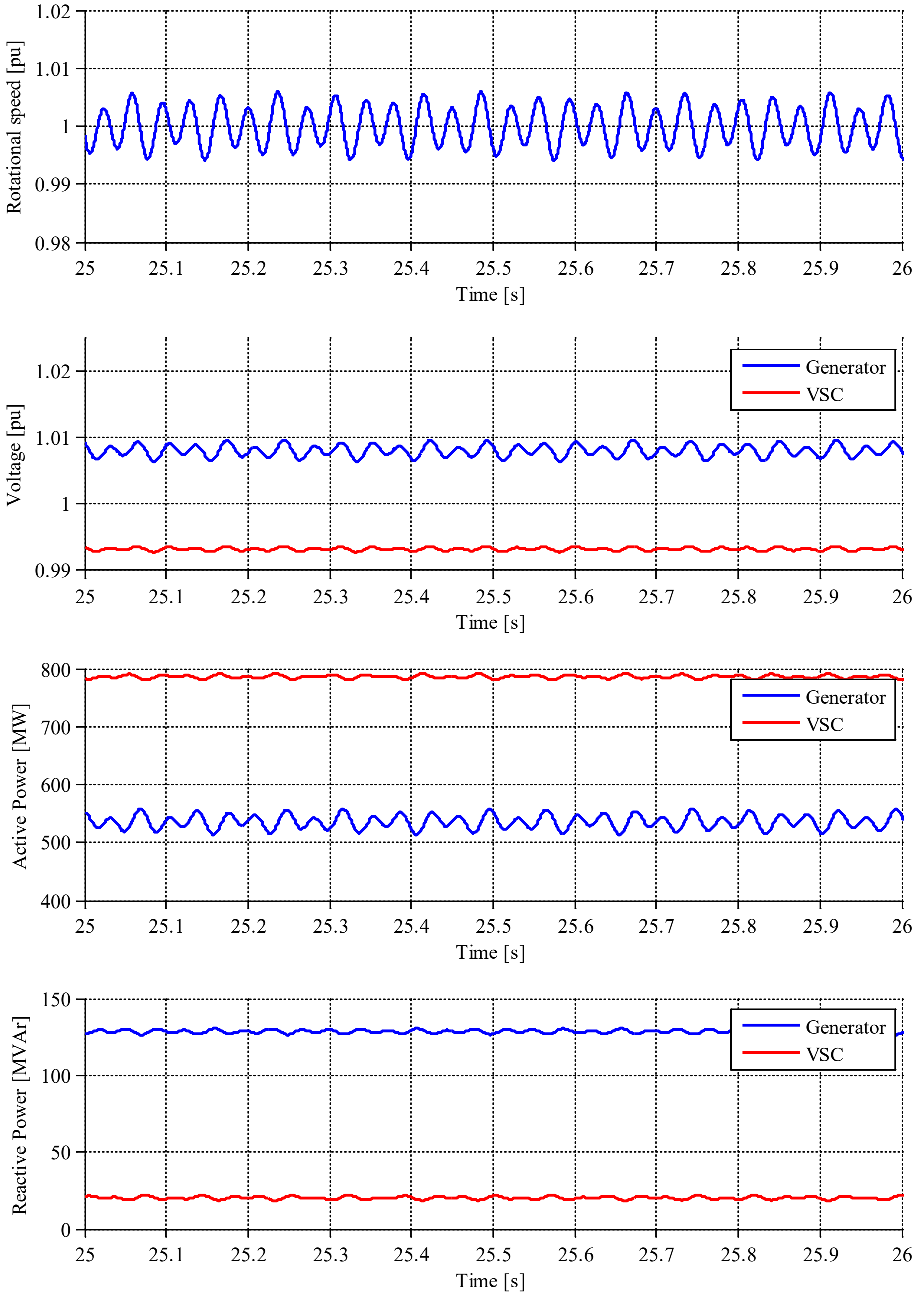

Figure 31 Time domain simulations for the generic test system with the VSC replaced by a voltage source.

There are obvious oscillations in the generator speed as well as in the voltage and power for both cases at about 28 Hz. For the case with the VSC, there are oscillations in the reactive power but not in the active power, which indicates that the oscillations are amplified by the reactive power controller in the VSC, in this case an AC voltage controller.

5.3 CONTROL PARAMETER VARIATIONS

To study the impact of the fast AC voltage controller present in the generic test system, which is the cause of the oscillations, the following modifications are made:

- Mod 1: Decrease the gain for the AC voltage controller to 20 % of the original value.
- Mod 2: Change to reactive power control.

The electrical damping is obtained for Mod 1 and Mod 2 and compared to the original case in Figure 32.

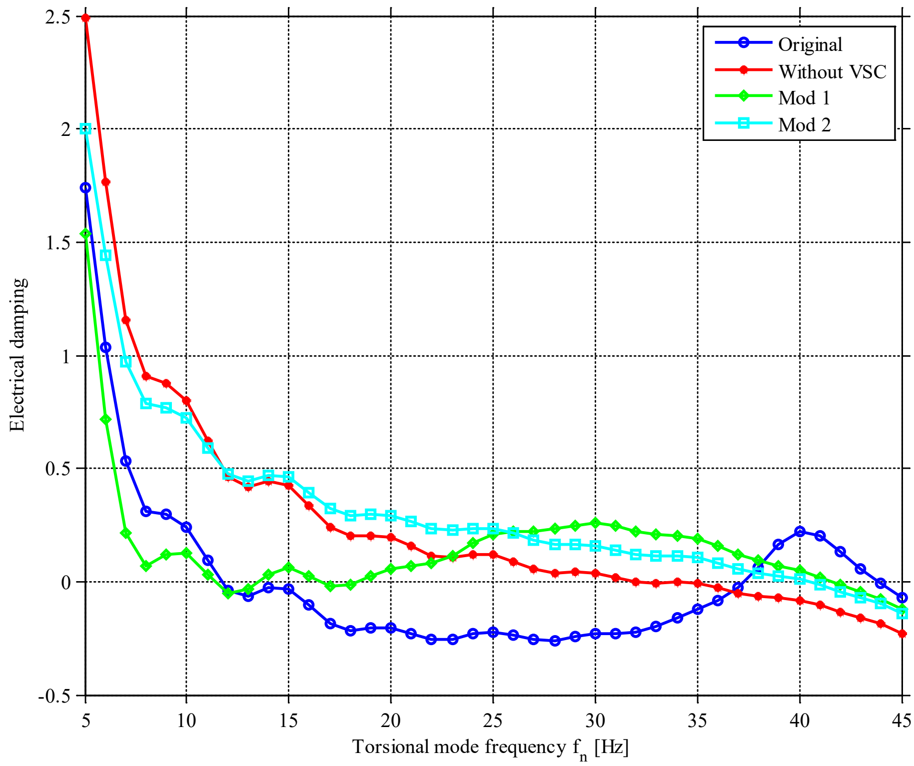

Figure 32 Electrical damping for the test system compared to Mod 1 and Mod 2.

It can be seen that lowering the gain for the AC voltage controller, as for Mod 1, or change to another controller, in this case a reactive power controller for Mod 2, will increase the electrical damping and therefore also reduce the risk for oscillations.

Also a frequency scan of the impedance of the HVDC seen from the generator bus is made for Mod 1 and Mod 2. The results for Mod 1 can be seen compared to the original control in Figure 33.

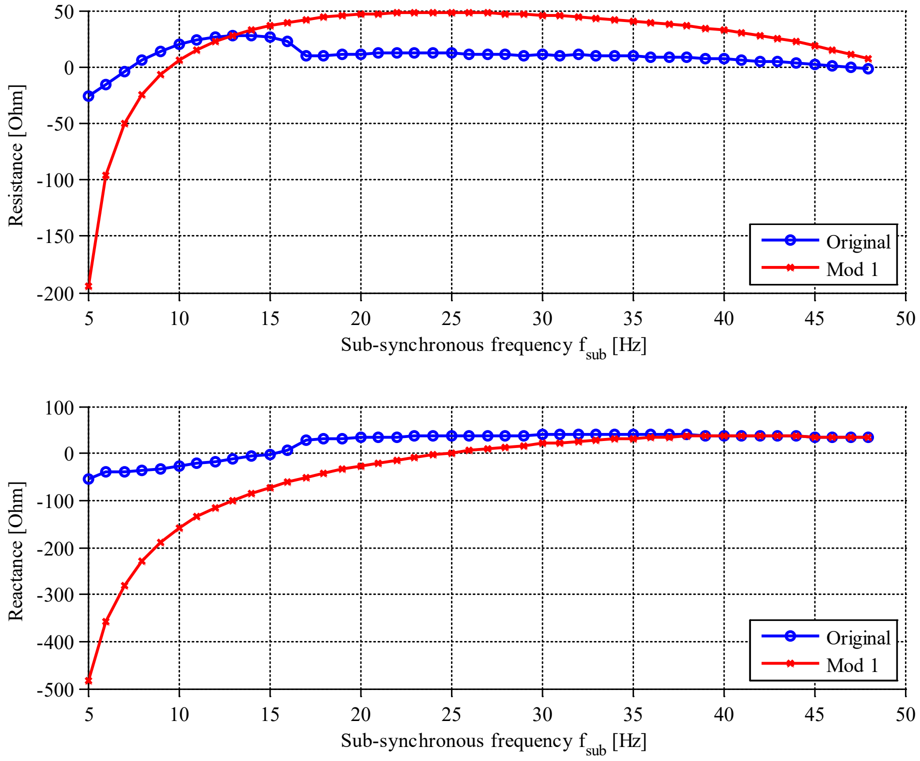

Figure 33 Sub-synchronous impedance for the VSC, Mod 1 compared to the original control.

Lowering the gain for the AC voltage controller will give a higher resistance at the sub-synchronous frequencies, f_{sub}, 50 - 16 = 34 Hz and 50 - 28 = 22 Hz, and the risk of amplification of oscillations at these frequencies is therefore reduced.

In Figure 34, also the sub-synchronous impedance for Mod 2 is shown and compared to the sub-synchronous impedance for the original case and Mod 1.

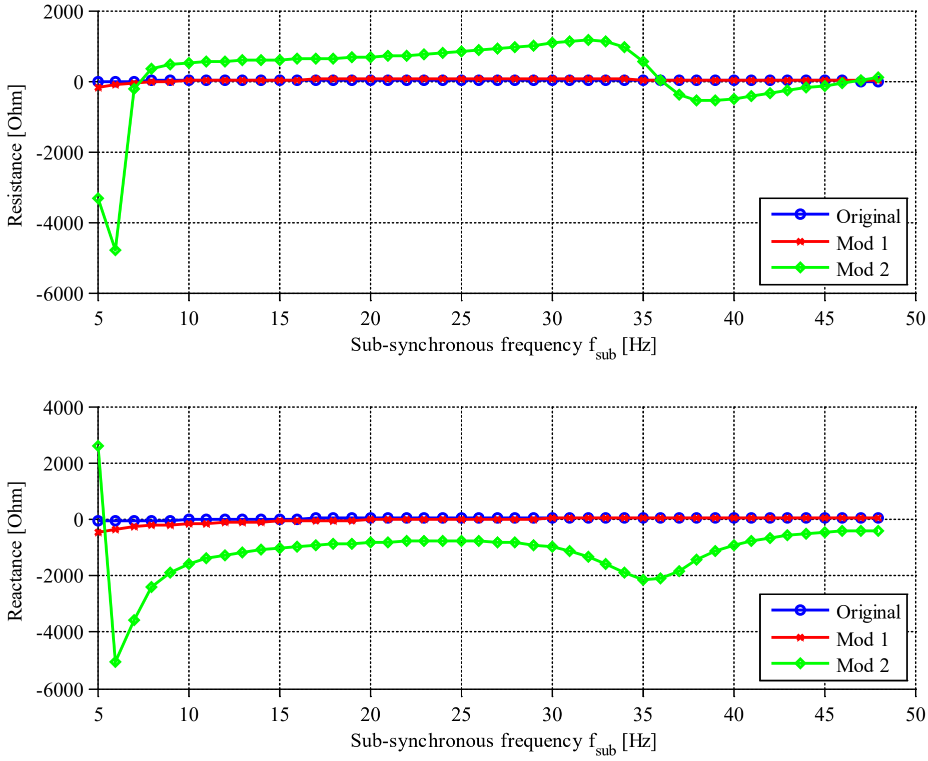

Figure 34 Sub-synchronous impedance for the VSC, Mod 1 and Mod 2 compared to the original control.

The sub-synchronous resistance for Mod 2 is significantly higher at the sub-synchronous frequencies and therefore the risk of amplification of these oscillations is even lower for Mod 2.

As seen by the electrical damping and the harmonic impedance, the risk of sub-synchronous oscillations is lower for Mod 1 and Mod 2 compared to the original case. The damping is expected to be higher for Mod 2 compared to Mod 1. This is verified by time domain simulation where the results are shown in Figure 35 for Mod 1 and in Figure 36 for Mod 2.

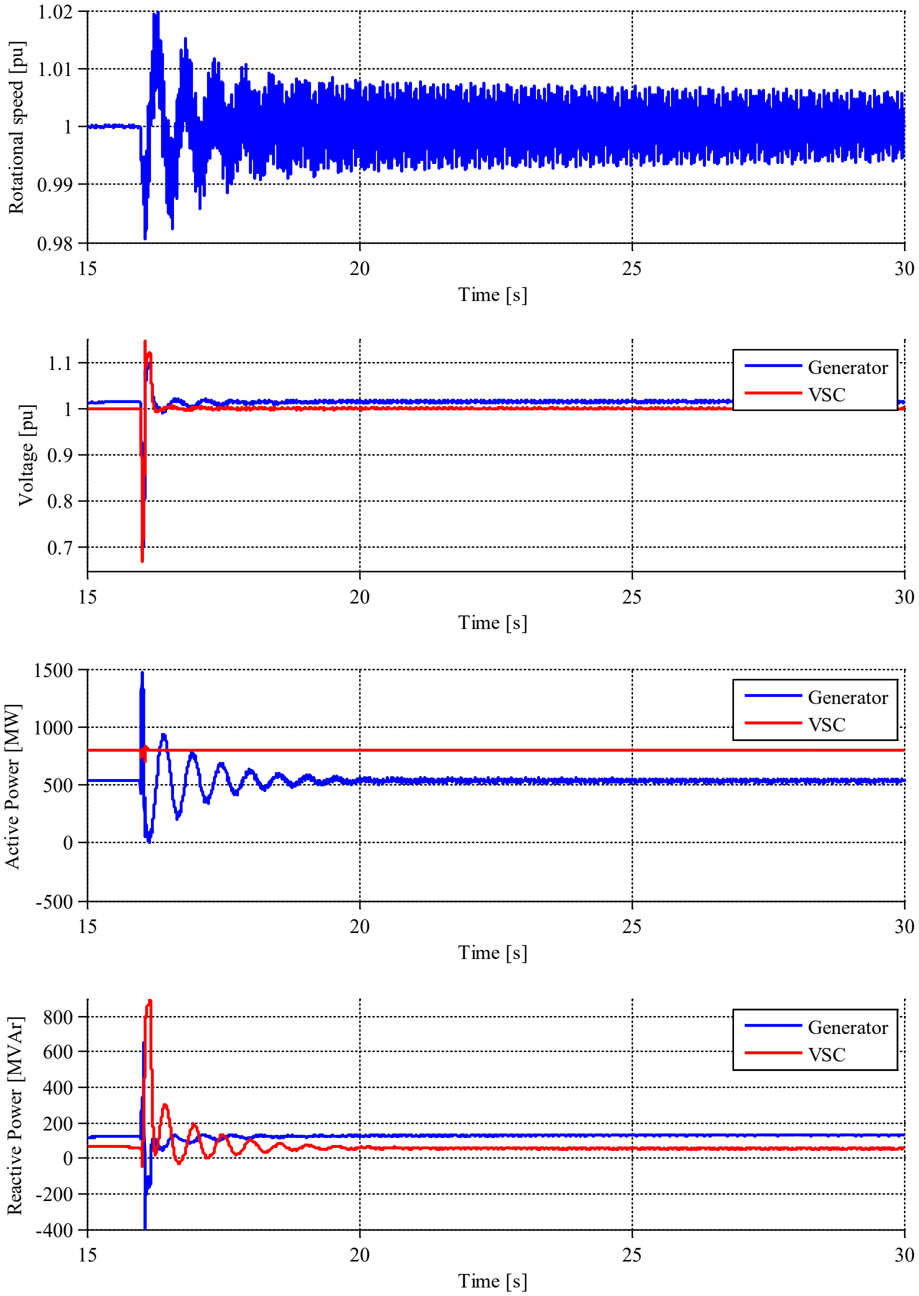

Figure 35 Time domain simulations for the generic test system with lower gain for Vac control, Mod 1.

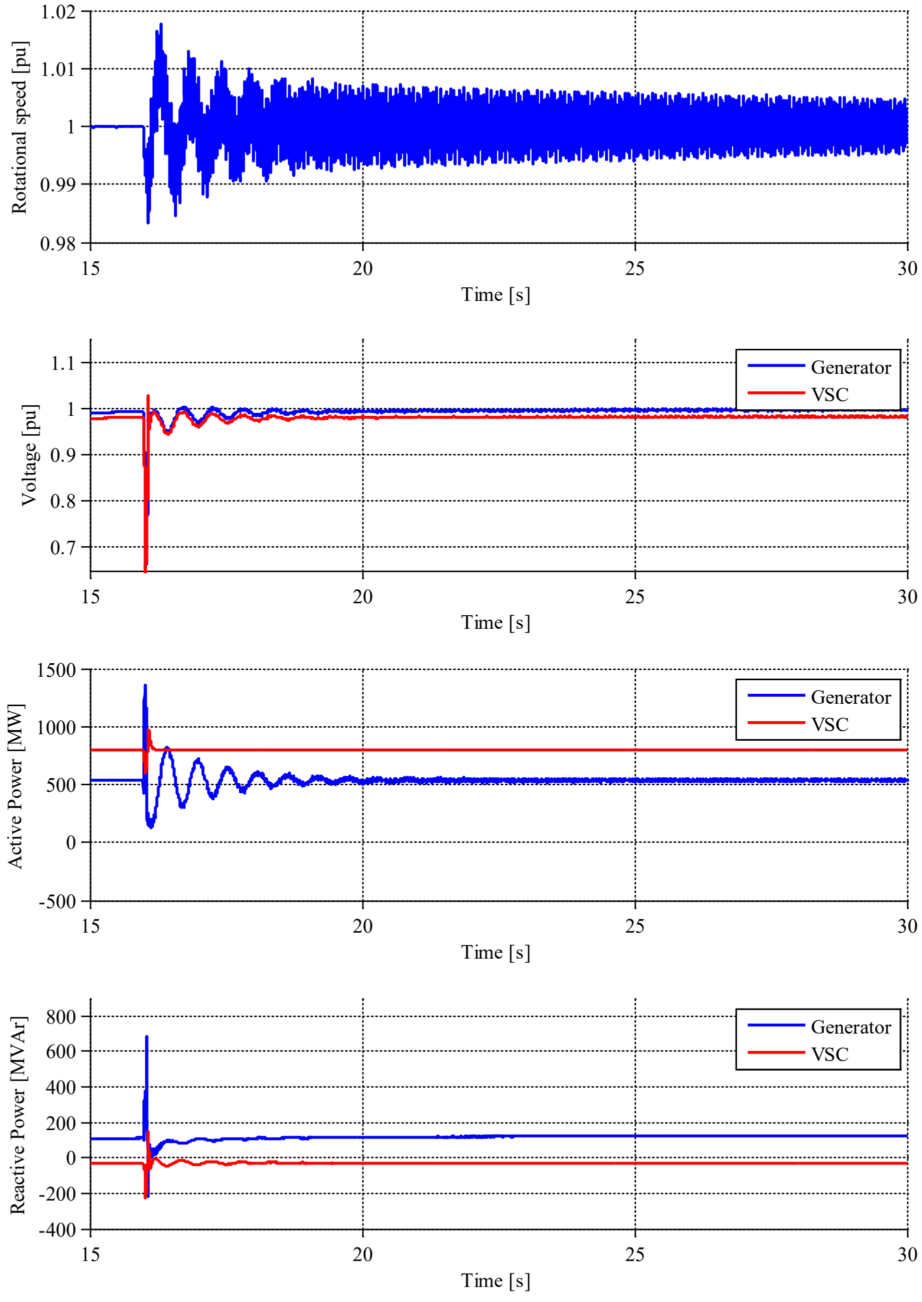

Figure 36 Time domain simulations for the generic test system with reactive power control, Mod 2.

As seen by the electrical damping, the sub-synchronous impedance and also the time domain simulations, the outer voltage controller has a large impact on the risk of sub-synchronous oscillations. In this particular case, the cause of the oscillations is the AC voltage controller, and by reducing the gain of the AC voltage controller or by changing to a slower reactive power controller will, in this case, result in damped oscillations.

It should be noted that changing the characteristics of the AC-voltage controller will have an impact of the performance of the controller. Reducing the gain of the

AC-voltage controller as made for Mod 1 gives larger variations of the AC-voltage, so while reducing the risk of sub-synchronous oscillations Mod 1 will result in larger voltage variations during normal operation. Instead changing the control to have a constant reference for reactive power, as for Mod 2, the system will in this case have a lower risk for sub-synchronous oscillations but the VSC will not control the AC voltage.

5.4 LOCATION IN THE SYSTEM

To identify the impact of the strength of the connecting grid, which in the original case is 5490 MVA, the following modification is made:

- Mod 10: Increase the short circuit power of the connecting grid to 10 pu of the original value, which gives an increase from 5490 MVA to 54900 MVA.

Note that the increased grid strength is for illustration purpose and the short circuit power is higher than the actual short circuit power in the grid.

When looking at the risk of oscillations between a VSC and a synchronous generator, the unit interference factor, UIF, is used as described in section 2.3. The UIF is calculated for each synchronous generator seen from the VSC.

The UIF_i for the i:th generator unit is defined according to [14]:

$$UIF_i = \frac{MVA_{HVDC}}{MVA_i}\left(1 - \frac{SC_i}{SC_{\mathrm{TOT}}}\right)^2 \tag{11}$$

where:

MVA_i is the MVA for the i:th generator unit

SC_{TOT} is the Short Circuit Capacity at the HVDC converter station with the i:th generator unit in operation

SC_i is the Short Circuit Capacity (fault level) at the HVDC converter station with the i:th generator unit disconnected

For the original case, the UIF is calculated as

$$UIF_{orig} = \frac{MVA_{HVDC}}{MVA_i}\left(1 - \frac{SC_i}{SC_{\mathrm{TOT}}}\right)^2 = \frac{1000}{600}\left(1 - \frac{5320}{6800}\right)^2 = 0.079$$

For the case Mod 10 with higher short circuit power for the grid equivalent, the UIF is calculated as

$$UIF_{Mod1} = \frac{MVA_{HVDC}}{MVA_i}\left(1 - \frac{SC_i}{SC_{\mathrm{TOT}}}\right)^2 = \frac{1000}{600}\left(1 - \frac{43450}{44700}\right)^2 = 0.0013$$

Looking at the requirements generally used for UIF, a value of UIF higher than 0.1 indicates that there is a risk of SSO between the VSC and the synchronous generator. In the original case for the generic test system, UIF is 0.079 which is close to the value indicating a possibility of SSO while Mod 10 with the strong grid has UIF 0.0013 meaning a very low risk of SSO.

The electrical damping is obtained for Mod 10 and compared to the original case in Figure 37. Note that the damping is changed with the short circuit impedance of the equivalent also for the case without the VSC connected.

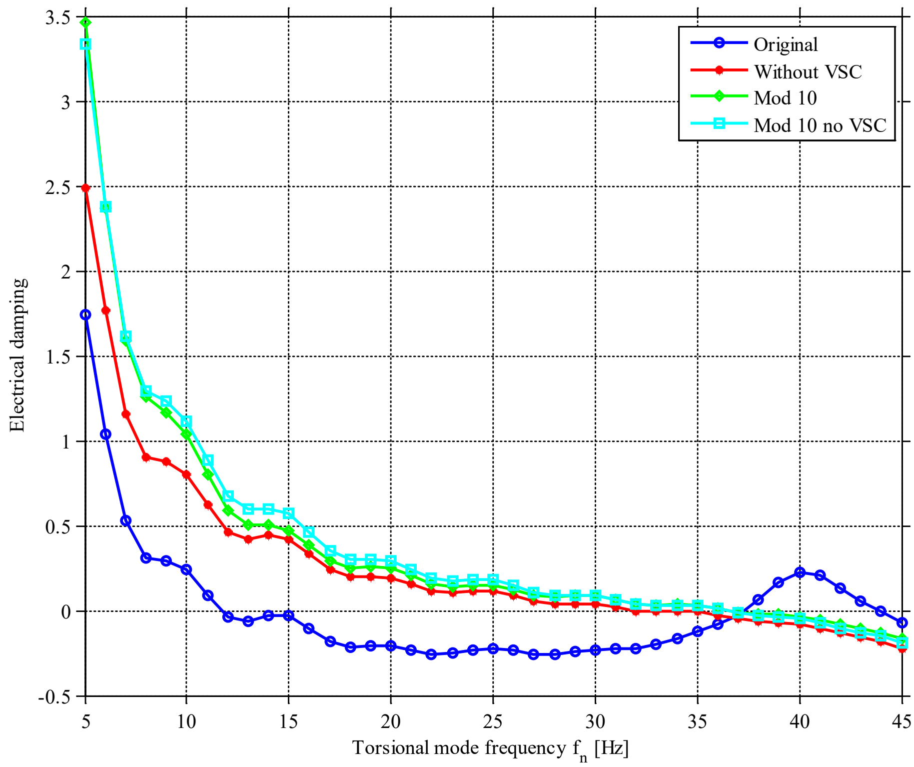

Figure 37 Electrical damping for the test system compared to Mod 10.

When having a strong grid as for the case mod 10, the VSC does not have a significant impact on the electrical damping and oscillations at the torsional modes are likely to be damped.

Since the VSC is not changed the sub-synchronous impedance for the VSC is the same as for the original case.

Looking at the electrical damping for Mod 10, it indicates a low risk for oscillations at the torsional mode frequencies, which is verified by a time domain simulation as seen in Figure 38.

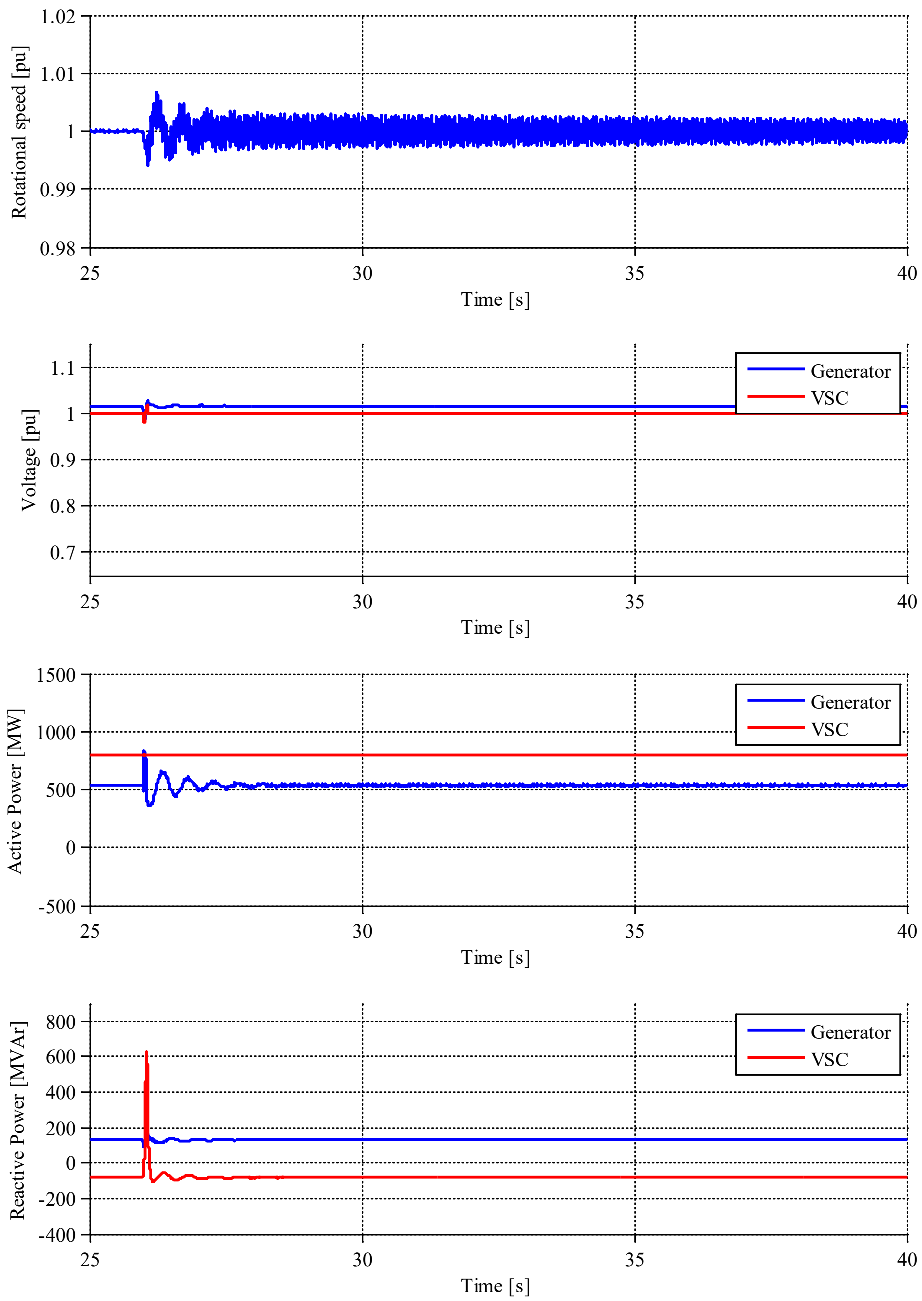

Figure 38 Time domain simulations for the generic test system with strong grid, Mod 10.

5.5 WIND TURBINE CONVERTERS

In the generic test system shown in Figure 23, there is one transformer between the transmission line and the VSC, which is the typical case for an HVDC converter. To study the impact of the connection on a lower voltage level, the modifications listed below are made:

- Mod 20: Add one additional transformer with ratio 1:1 between the VSC transformer and the VSC bus as shown in Figure 39.
- Mod 21: Add one additional transformer with ratio 1:1 between the VSC transformer and the VSC bus as shown in Figure 39. Also reduce the gain of the AC voltage controller to 20 % of the original value.

This is made to include the impedance of the wind turbine transformer, but the ratio is chosen to 1:1 to keep the same converter model. The added transformer has rated voltage 415 kV, rated power 1200 MVA and short circuit voltage 0.1 pu.

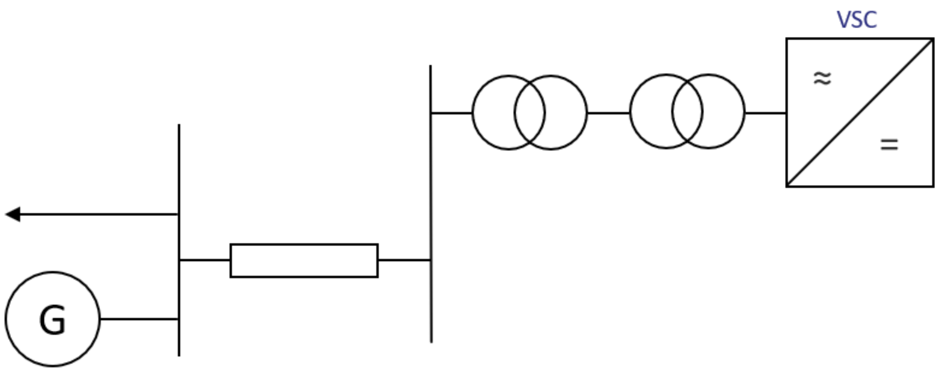

Figure 39 Generic test system with one additional VSC transformer for Mod 20.

For this case, the VSC can be seen as an aggregated model for 500 WTGs of 2 MW each where each turbine has a turbine transformer and the whole wind park has another transformer for the grid connection. This is an assumption made in this study and an aggregation is often made for large wind farms if it is not possible to model all wind turbines in detail. However, it should be noted that the internal grid in the wind park (often cables grid) can impact the results as well as possible deviations in operation between the wind turbines.

For the case Mod 20 and Mod 21 with two transformers for VSC, the UIF is calculated as

$$UIF_{orig} = \frac{MVA_{HVDC}}{MVA_i}\left(1 - \frac{SC_i}{SC_{\mathrm{TOT}}}\right)^2 = \frac{1000}{600}\left(1 - \frac{3738}{4313}\right)^2 = 0.030$$

The UIF for case Mod 20 and Mod 21 is 0.03 which is lower than the original case and also a value which is generally considered to indicate a low risk of SSO.

The electrical damping is obtained for Mod 20 and Mod 21 and compared to the original case in Figure 40.

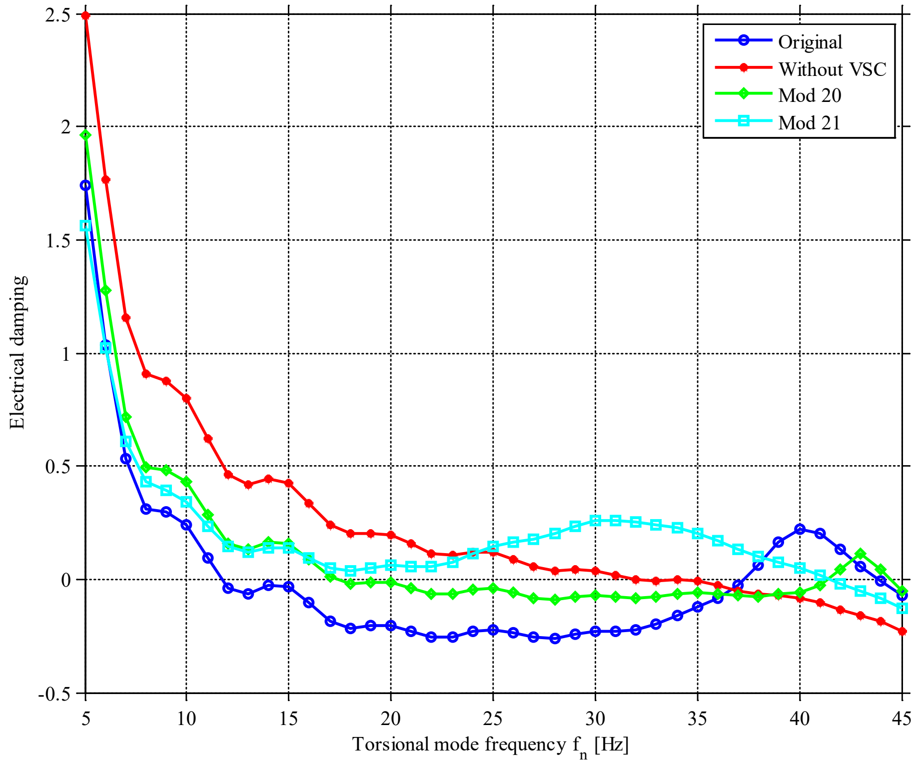

Figure 40 Electrical damping for the test system compared to Mod 20 and Mod 21.

When having one additional transformer, the electrical damping is higher and the risk of oscillations at the torsional frequencies is reduced.

Looking at the electrical damping for Mod 20, it indicates a low risk for oscillations at the torsional mode frequencies, and for Mod 21 with a lower gain for the AC voltage control the risk of oscillations is further reduced.

The extra transformer added for Mod 20 and Mod 21 gives a weaker grid, resulting in large oscillations caused by the voltage controller when the same parameters are used as in the original case. Since the original AC voltage controller is badly tuned for the weaker grid, the AC voltage controller used in Mod 21 is considered more likely.

The time domain simulation for Mod 21 is shown in Figure 41 and verifies that there are no amplified oscillations as indicated by the electrical damping.

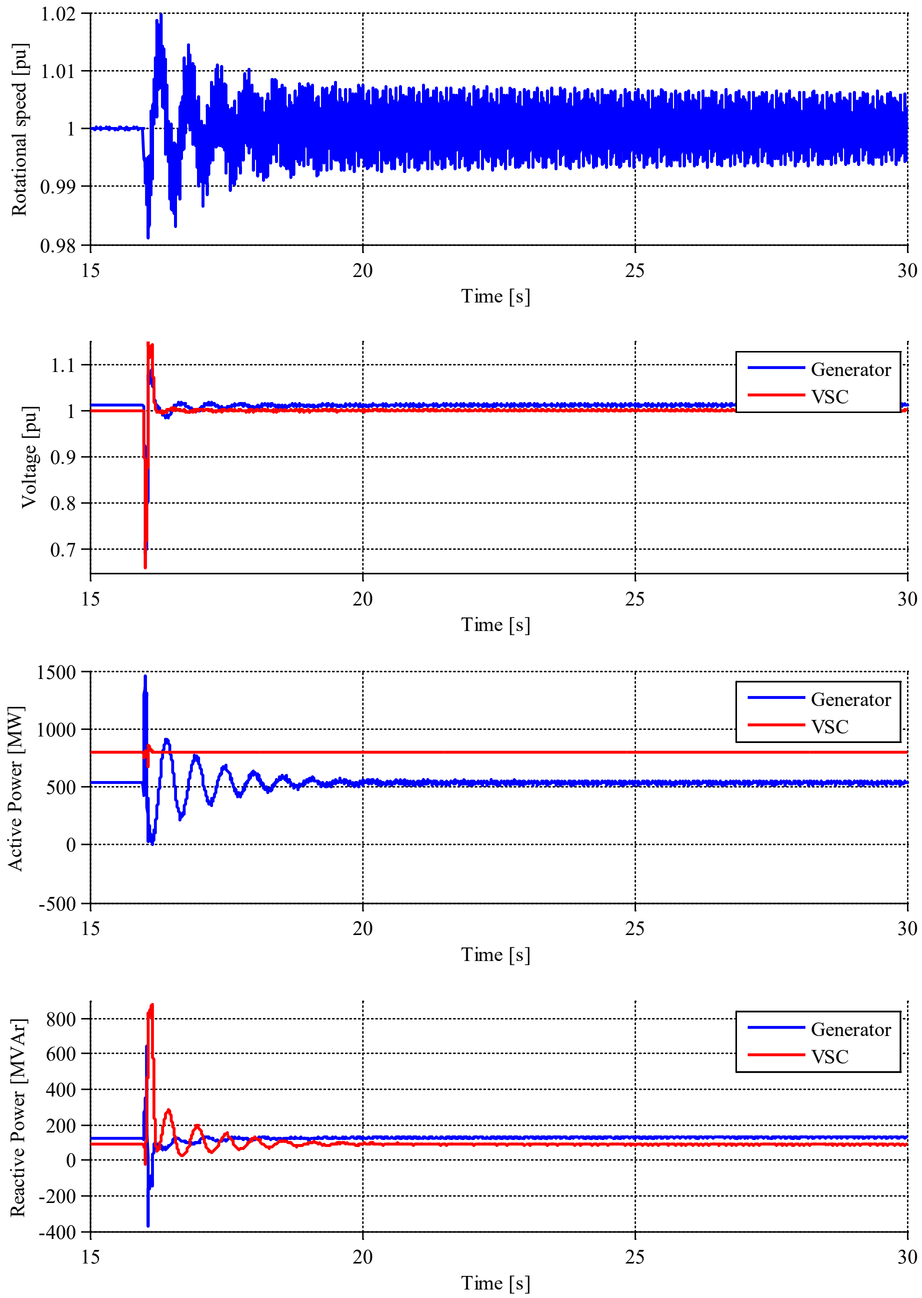

Figure 41 Time domain simulations for the generic test system one additional transformer and lower gain for the AC voltage controller, Mod 21.

5.6 SUMMARY OF RISK FOR SSO

Studying the examples above, some general trends can be seen:

- A strong grid will reduce the risk of SSO. A possible future decommissioning of synchronous generation can reduce the grid strength and increase the risk of SSO.
- A larger impedance between the synchronous generator and the VSC will reduce the risk of SSO. Here is a difference between wind power and HVDC where the HVDC converter generally just has one transformer between the converter and the transmission system while the wind turbine converter usually has two converters up to the transmission system.
- The UIF that indicates a risk of SSO agrees well with the results in this example.
- The controller of the VSC has a very large impact on the SSO. The frequency range for SSO coincides with the frequency range of the PLL and the outer control for active and reactive power. In this example it is the AC voltage control that causes the oscillations, but each converter has its own control loops and must be studied independently.

Since the control loops have a very large impact on the risk of SSO, it should be noted that even an update of the control system of a large VSC, or all VSCs in a wind farm, might require a new evaluation regarding SSO. For example, a change from a relatively slow active/reactive power controller for an energy storage to a control as a virtual synchronous generator can change the risk for SSO.

5.7 OSCILLATIONS BETWEEN CONVERTERS

In power systems with many large grid connected voltage source converters, there is a risk of oscillations between two converters. In this case there are no torsional modes that define the possible frequencies for oscillations, instead the oscillations can occur at any frequency.

For studying the principle of SSO between two VSCs a second generic test system is used. The two main components in the model are the VSC modelling a wind park and the VSC modelling a HVDC transmission as seen in Figure 42.

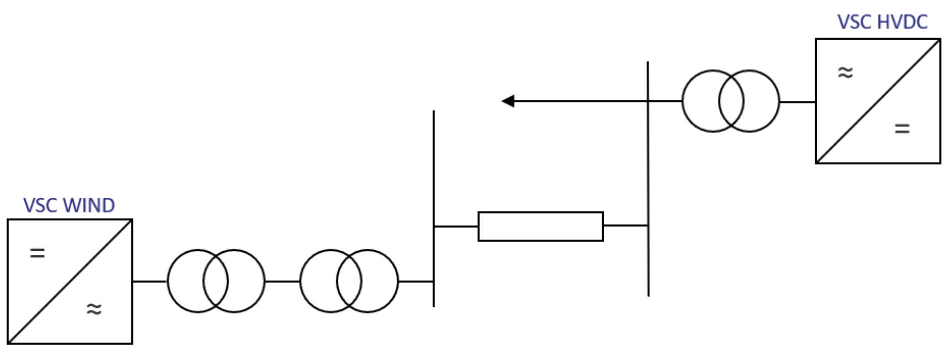

Figure 42 Second generic test system.

In the model, there is also an impedance between the wind farm and the HVDC as well as an equivalent grid model connected to the HVDC bus.

The system voltage is 415 kV and the short circuit power at the HVDC bus from the grid equivalent is 6100 MVA and the short circuit power at the wind park bus from the grid equivalent is 4900 MVA. The rated power of the HVDC link is 1000 MW and the wind park is rated 500 MW.

To evaluate the risk for oscillations, a frequency scan is made for the impedance for both the wind park seen from the HVDC bus, Z_{wind}, and the impedance for the HVDC and the connected grid seen from the HVDC bus, Z_{HVDC} as seen in Figure 43. In this example the single-valued complex impedance is studied and any unsymmetric impedances, as mentioned in Section 3.2.3, is not considered here in this simplified example.

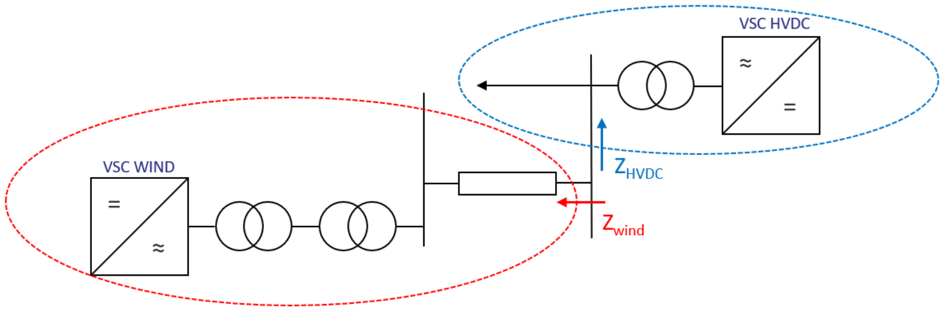

Figure 43 Frequency scan of the impedance for the second generic test system.

When performing the impedance scan, a time simulation is made with a sub-synchronous frequency component is injected either as a current or as a voltage. One simulation is made for each sub-synchronous frequency of interest and the impedance is calculated for that frequency.

The time simulations for the wind park are made by connecting a voltage source including injected sub-synchronous voltage harmonics at the 415 kV bus. The HVDC and the grid equivalent is not included in the simulation.

For the time simulation including the HVDC parallel connected to the grid equivalent, it is not suitable to connect another voltage source at the HVDC bus since there is already a voltage source in the system. Therefore, a sub-synchronous current is injected at the HVDC bus instead.

The control of the HVDC is the same in all simulations but for the wind park VSC the controller is implemented both with a fast phase locked loop and a slow phase locked loop. The phase-locked loop is tracking the frequency and the phase of the voltage and having a fast PLL will detect changes in the frequency and phase faster, for example in case of disconnection of a line. The resulting harmonic impedance is seen in Figure 44 and Figure 45.

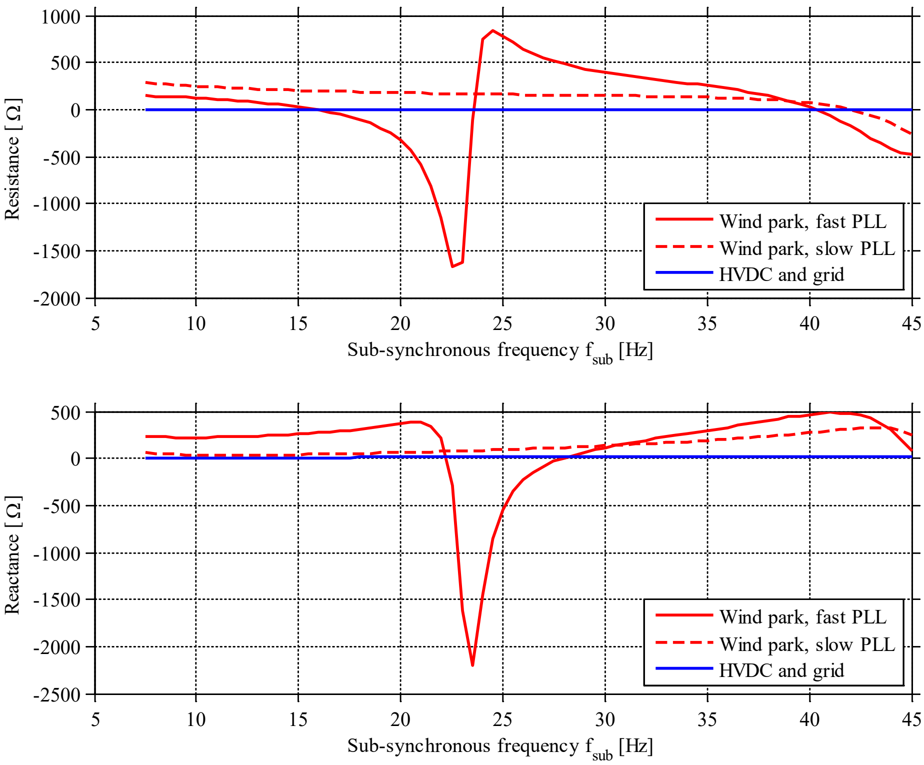

Figure 44 Sub-synchronous impedance for the second generic test system.

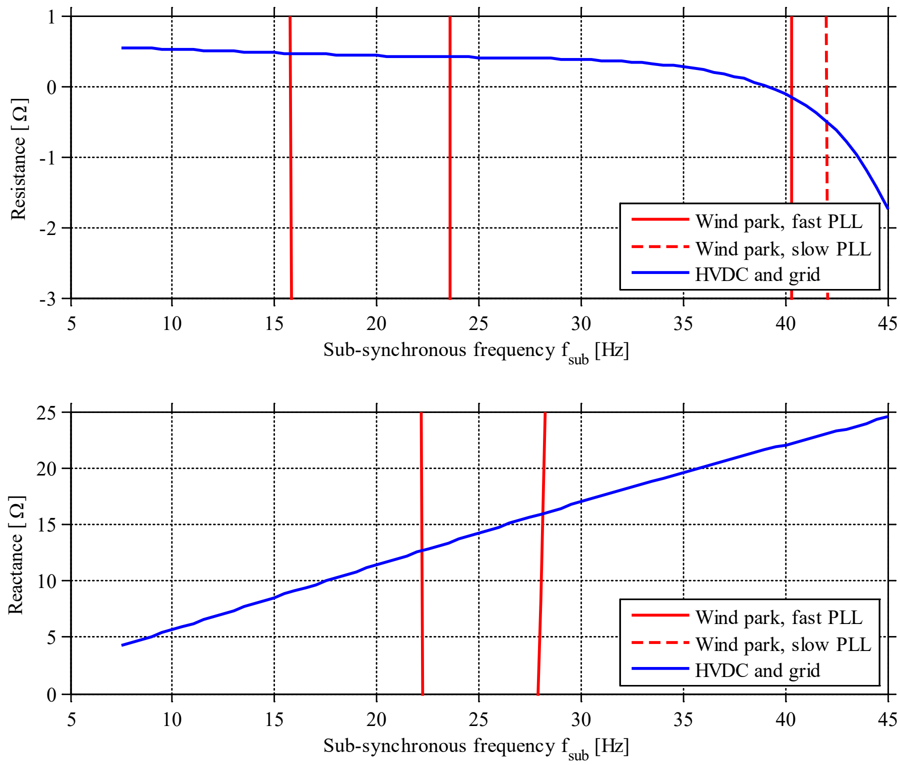

Figure 45 Sub-synchronous impedance for the second generic test system, zoomed figure.

From the sub-synchronous impedance, it can be seen that the resistance for the HVDC in parallel with the grid equivalent is small but positive until 39 Hz where it gets negative. For the wind park, the bandwidth of the PLL gives a large difference, where the slow PLL gives a positive resistance up to 42 Hz. For the fast PLL there is a large variation in both the resistance and the reactance at the sub-synchronous frequencies. Between 22 Hz and 23 Hz the reactance goes from positive to negative and the resistance has a negative peak. This indicates a resonance and a risk for oscillations.

Note that in this example the VSC-HVDC is chosen to be electrically closer to the strong grid. It is not the application (wind, HVDC, solar etc…) itself that cause the oscillation, it is due to the converter. In this illustrative example the wind park is chosen to be the cause of the oscillation. In reality, it may be any converter-controlled equipment (or combination of) that cause the oscillations.

Time simulations for the test system with both the slow PLL and the fast PLL for the wind park are made with a step in the active power for the wind park at 2 s. The results are shown in Figure 46 for the slow PLL and in Figure 47 for the fast PLL.

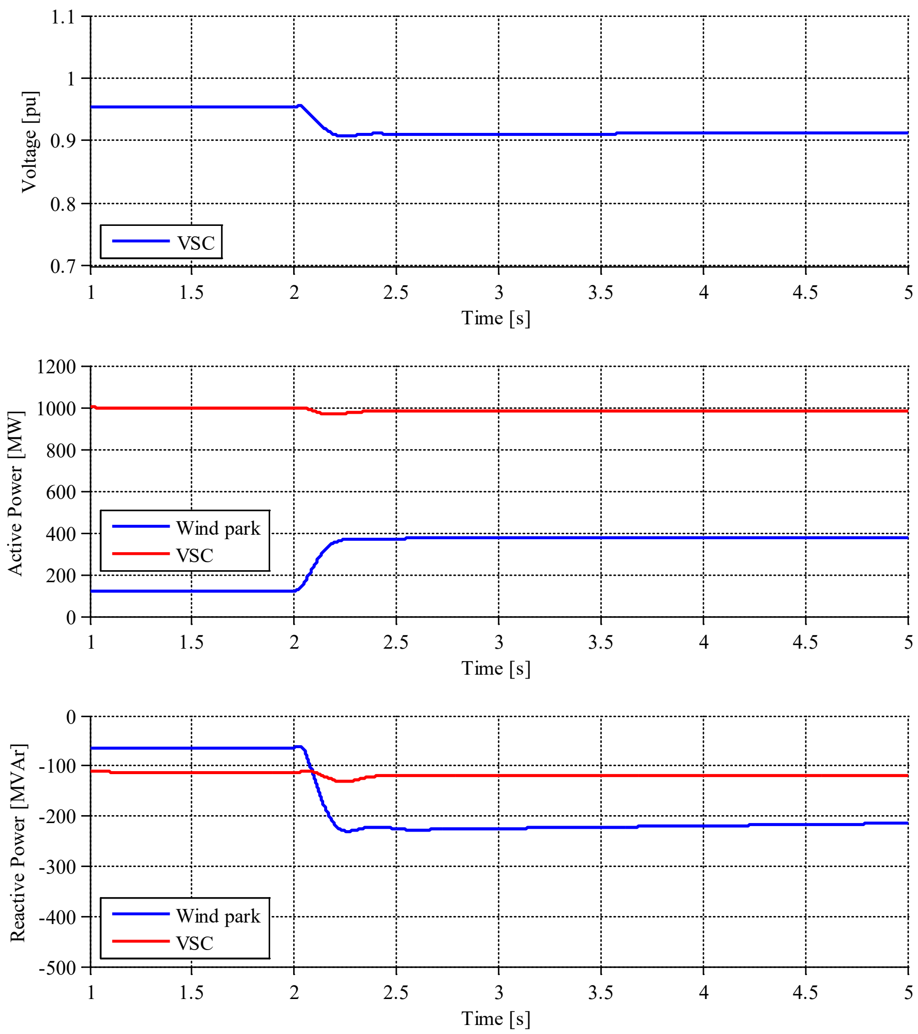

Figure 46 Time domain simulations with the second generic test system, slow PLL for the wind farm.

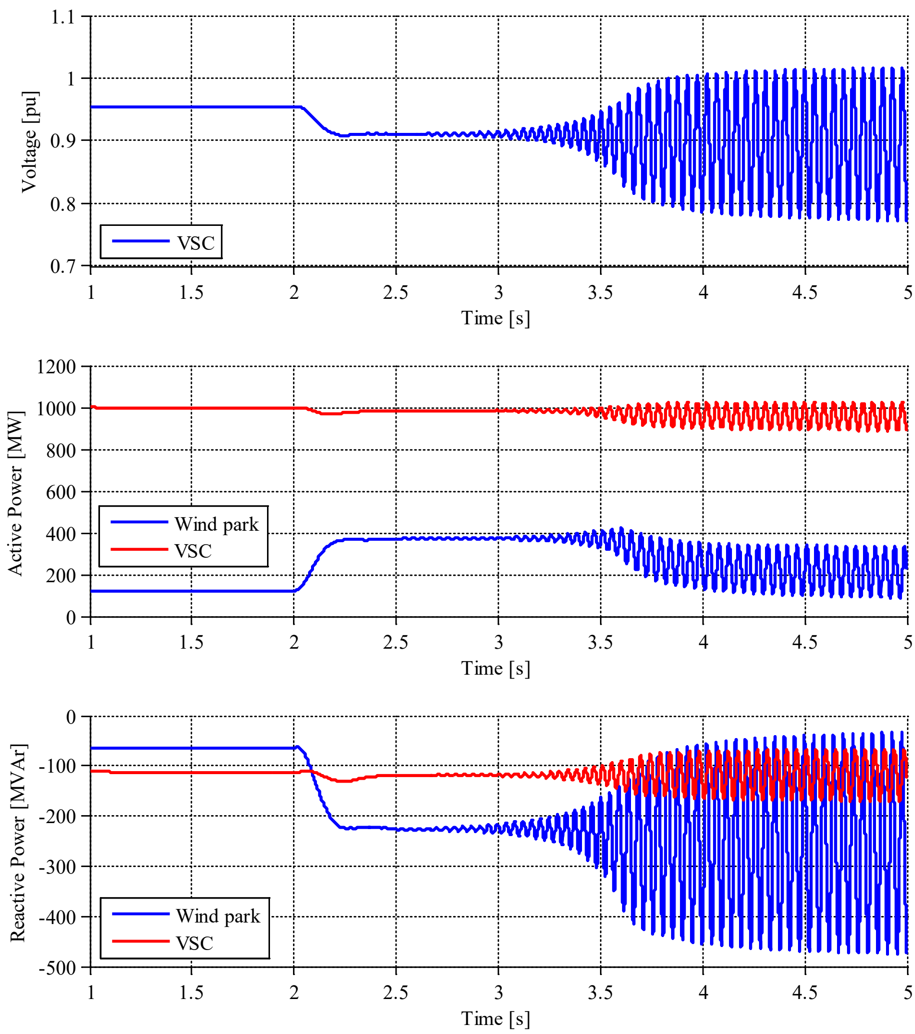

Figure 47 Time domain simulations with the second generic test system, fast PLL for the wind farm.

For both test systems, the operation at low power for the wind park is stable. However, when increasing the active power in a step the system with the wind park with slow PLL is stable while the test system with the fast PLL for the wind park shows amplified oscillations. The sub-synchronous oscillations have a frequency at about 21 Hz as seen in Figure 48. This also indicates that the results depend on the operating condition of the VSC (e.g. a high or a low power level).

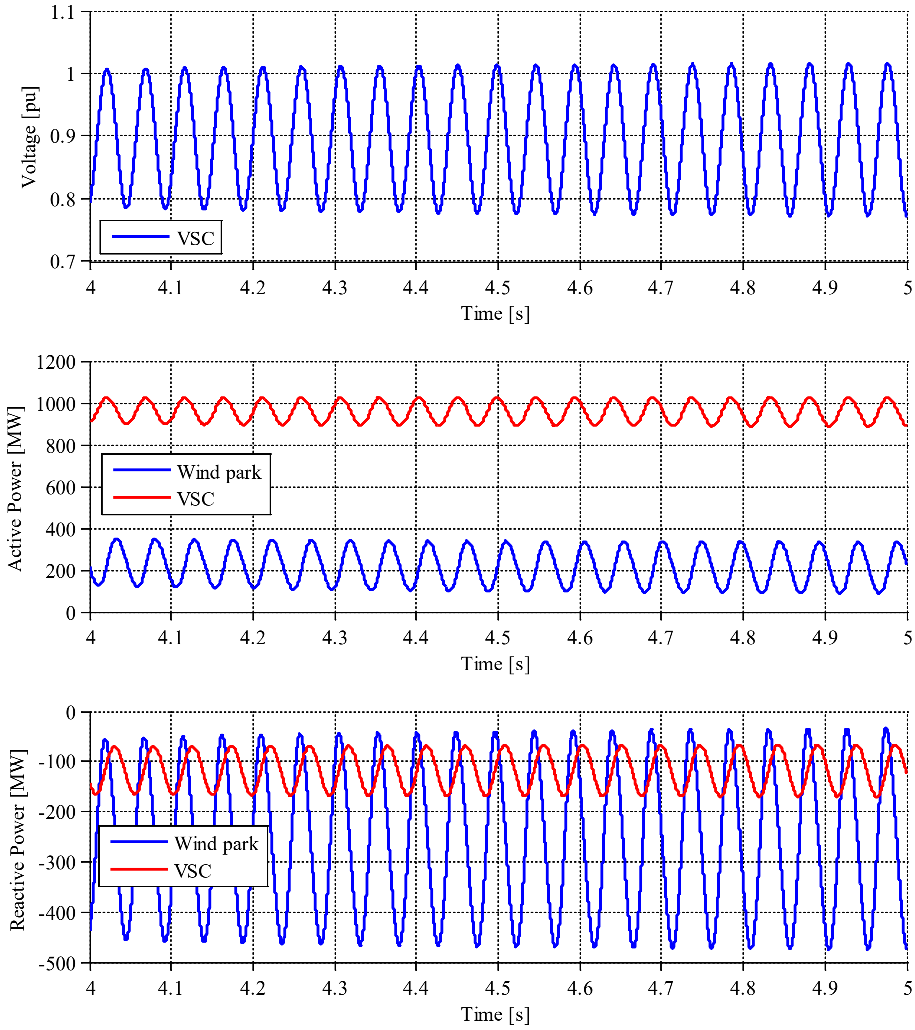

Figure 48 Time domain simulations with the second generic test system, fast PLL for the wind farm.

6 Discussion

The risk of obtaining sub-synchronous oscillations depends on many different factors such as the size and the design of the generator, the location in the system and the size and control of the VSC as well as the operating point.

In this chapter, the results in the report are discussed according to the suitability of the proposed study methods, the parameters affecting the risk of SSO to occur and the frequency intervals where SSO can occur.

6.1 RISK OF SSO

As seen in chapter 5, there are some factors that influence the risk of SSO. A large synchronous generator and a large VSC compared to the grid strength increase the risk of SSO. Also, if the generator is located close to the VSC there is an increased risk of oscillations. The mechanical damping of the torsional modes for the turbine-generator set is important and given by the design of the generator.

It should be noted that the risk of SSO is strongly depending on the operating conditions. Connecting or disconnecting grid components such as lines, cables, reactors or capacitors to the system will change the impedance of different frequencies and can therefore impact the risk of SSO. Also, the operating condition of the synchronous generator can influence the risk of SSO.

Looking at the VSC, the characteristics that influence the risk of SSO are the outer control loops. With the increasing demands on performance on the grid connected VSCs, these control loops can be affected. A VSC can for example act as grid forming converter or be providing virtual inertia. Changing the control of the converter will strongly affect the risk of SSO and each converter therefore must be studied in detail.

6.2 EVALUATION OF THE STUDY METHODS

The study methods are described theoretically in chapter 3 and selected study methods are implemented for a generic test system in chapter 5. Here, a summary is made for the study methods focusing on the suitability for a system with a synchronous generator and a VSC.

Analytical – time domain and frequency domain

As seen in chapter 3, the analytical methods require complete information about the system, including control methods. This makes the method suitable for research and development where the complete system is known. In this case, with a generator and a converter including control, which is usually not known for the user, this is not a suitable method and it is not studied further.

Impedance frequency scan

Performing impedance frequency scan using the built-in frequency scan component in for example PSCAD gives the impedance at each frequency for the circuit elements such as resistance, inductance and capacitance. This method is fast and can be suitable to find possible resonance points for a grid that is modelled using circuit elements. However, for the test system that is including both control of the generator and the converter, this method is not suitable since the controls are not included.

Complex torque method

The complex torque method gives the electrical damping of the system as seen from the rotor of the generator. This is a suitable method for possible sub-synchronous oscillations including a generator and not suitable for control interaction between two converters.

The results using the complex torque method is the electrical damping as a function of the frequency and the risk for amplified sub-synchronous oscillations can be evaluated at the torsional mode frequencies for the generator. Having a negative electrical damping at any of the torsional mode frequencies indicates a risk of amplified sub-synchronous oscillations.

Since the electrical damping is given for the whole system, including grid components, series compensation and converters, the damping for the VSC itself is not given. However, the electrical damping can be obtained for the system including the VSC and excluding the VSC to find the impact on the electrical damping from the VSC. The example shows that a change in the control gives a clear impact on the electrical damping and the risk of amplified sub-synchronous oscillations.

Note that the complex torque method just considers oscillations including the generator, it does not evaluate other oscillations such as oscillations between two VSCs in the system.

The complex torque method requires a time simulation for each frequency and is therefore quite time consuming.

Impedance/admittance scanning by dynamic simulations

The impedance scanning gives a value of the impedance/admittance at each frequency. This method can be applied at any component or part of the system.

The results from the method is the impedance at each frequency and a low (or negative) resistance at the torsional mode frequencies for the generator can indicate on a risk of amplified sub-synchronous oscillations. The results show the impact of a change in the system, for example if a control change gives a higher resistance at the torsional modes the risk for amplified oscillations is reduced.

If there are oscillations between two VSCs or between a VSC and a series compensation, the complex torque method can not be used, instead the impedance scan by dynamic simulations is used. Having a zero crossing of the reactance and at the same frequency negative peak in the resistance indicates a risk of oscillations.

In the same way as for the complex torque method, the impedance/admittance scanning by dynamic simulations requires one time-domain simulation for each frequency and is therefore quite time consuming.

Time domain simulations

Time domain simulations is important to verify conclusions from the studies using the complex torque method and the impedance/admittance scanning. If the mechanical damping of the generator is not known, it is important with time domain simulations to study if the oscillations will be damped or amplified. It is also important to include possible non-linear functions in the model such as saturations in the controller.

Unit interference factor

The Unit Interference Factor (UIF) is a parameter to assess the risk of torsional interaction between a generating unit or power plant and an HVDC converter. Using this factor, it can be decided if there is any risk of oscillations between a VSC and a synchronous generator. A screening of the UIF is usually made as a first part of the study to identify where there is a risk amplified oscillations. From the example, it is shown that the UIF is a good indication on if a generator is close enough to a VSC to have a risk of SSO However, since the UIF factor is mainly verified for LCC converters, it is recommended to lower the limit of UIF from 0.1 for deciding if a study of possible SSO between a generator and a VSC should be performed. In the example the UIF for the case with amplified SSO was 0.079, which is lower than 0.1 but still in the same range.

The results for the UIF are only based on the size of the VSC and the generator and their location in the system and show if these components are close enough and located in the system in a way that gives a risk for sub-synchronous oscillations.

The UIF is normally used when screening synchronous generators for possible interaction to an HVDC converter. It can also be used to assess the size of a VSC to be connected close to a synchronous generator. By calculating the possible size of the VSC where the UIF does not exceed the decided limit for the nodes close to a synchronous generator, it can be evaluated for which nodes the largest realistic size of a VSC gives a risk of SSO. This study is relatively easy to perform and not very time consuming since it in principle only requires short-circuit calculations. However, to obtain reliable results a grid model (typically in PSS/E or Power Factory) from the grid owner is required. This to ensure that the short-circuit power and operating conditions are correct and the possibility to consider contingencies.

6.3 PROPOSED STUDY METHOD

As seen from the example, a suitable method for the system including a synchronous generator and a VSC is to use the complex torque method to evaluate the risk of amplified oscillations for the generator. Using this method, the whole system is included, including converters and control, series compensation, cables and other grid components. If a large converter should be added close to a synchronous generator it is recommended to evaluate the electrical damping with the VSC and without the VSC to find the impact of the VSC on the electrical damping at the torsional mode frequencies. Then the conclusion can be made if the VSC to be connected will increase the risk of sub-synchronous oscillations.

If the mechanical damping is not known, time domain simulations are important to find if there will be amplified sub-synchronous oscillations.

If the frequency response of a special part of the system should be studied for the case mentioned above, or if an electrical resonance should be found, an impedance frequency scan can be made. If the system/component of interest contains anything else that standard circuit parameters, the frequency scanning must be made using a time domain simulation at each frequency.

If the oscillations of interest do not include a synchronous generator, the impedance frequency scan is used to evaluate the risk of sub-synchronous oscillations.

When using the complex torque method and impedance frequency scan, it is important to verify the results with time domain simulations to include non-linear conditions.

Also, the Unit Interference Factor (UIF) is a useful tool to identify where there is a risk for amplified sub-synchronous oscillations and should be used to decide where further studies are needed.

6.4 FREQUENCY INTERVALS

Looking at the frequency intervals for possible sub-synchronous oscillations, it can be said that for oscillations including the torsional modes for the generator, all torsional modes for the generator with low damping should be studied. Examples given in [28] show torsional modes from about 7 Hz to a few Hz below the synchronous frequency (50 Hz or 60 Hz).

The risk of resonance depends on the system including grid components, series compensation and converters including control etc., and is different for all systems. Therefore, it is recommended that all torsional modes are taken into consideration.

In the example used in this report, for example Figure 32, it can be seen that the electrical damping is negative between 12 Hz and 37 Hz for the original system with the VSC.

It is also shown that the electrical damping is strongly dependent on the control of the converter, which can vary strongly depending on the operation on the converter. In [46] it is stated that the rise time for application controls, which include the higher-level controls such as voltage controls, is in the range 1 ms to 1 s. Therefore, no general conclusions can be made regarding frequency intervals where VSC have a risk of SSO. Instead, each VSC has to be studied independently and the controller has to be properly designed in order not to avoid the risk of oscillations.

6.5 MODELLING OF A WIND PARK

When modelling a wind park, there are many components to consider. It can be a large number of turbines, there is an internal grid, often cables, and also a park controller. Studying the literature, the common way of modelling a wind park is to use an aggregated model for the wind turbines, which is a model similar to a single wind turbine, but the power is increased to represent the correct number of wind turbines in the park. An aggregated model is also used for the wind turbine transformers and the internal grid in the wind farm.

When performing analytical evaluation of sub-synchronous oscillations, the complexity is increased significantly if more than one aggregated wind turbine model should be used. When performing an evaluation based on frequency scanning and /or time domain simulations using a dynamic simulation model, more wind turbine models can be used. However, if having a large number of wind turbine models, the simulation model will be large with increased complexity and simulation time.

An aggregated model of a wind farm assumes identical wind turbines which are operating at the same operating point. Looking at amplification of sub-synchronous oscillations, having all wind turbines operating at the condition that gives most amplification for oscillations at a certain frequency is deemed to give the worst case. Thereby, an aggregated model is deemed suitable for showing if there is a risk of oscillations.

What is not included in an aggregated model is the difference in dynamic operation of the wind turbines due to the different lengths of cable and/or OH line to the collection point and the impact of the difference in operating point. If there are different types of wind turbines in a park, one aggregated model should be made for each type.

6.6 FUTURE RESEARCH TOPICS

The issue of sub-synchronous oscillations between large synchronous generators and VSCs is a topic of high importance considering the large increase of penetration of VSCs in the power system. This report is an introduction to the subject and reflects the state of the research at the present time. Since the subject of SSO including converters is a relatively new research topic, there are several important topics where research is ongoing. In the review of the current research made in this report, the following subjects have been identified as interesting research topics to follow:

- The risk of SSO for multi-terminal HVDC systems.
- General consequences of emerging control strategies such as grid forming converters and virtual synchronous machines.
- Possible mitigation function in addition to the SSDC function described in section 4.3.4.
- The effect of having a large number of smaller converters instead of one large converter. For example, having a large wind farm where wind turbines might

operate at different active and reactive power as well as the possible impact of differences in the dynamics of the controller in the converters.

- The suitable limit for UIF for oscillations between a large synchronous generator and a VSC.
- Different methods for frequency scanning, specially how unsymmetric frequency scanning is implemented in a more complex system.

7 Conclusion

In this report, study methods suitable for evaluation of sub-synchronous oscillations between large synchronous generator and voltage source converters (VSCs), such as HVDC converters and large wind farms, are evaluated.

For the grid connected voltage source converters, there are many different topologies. Newly installed HVDC converters are generally modular multi-level converters while the wind turbine converters more tend to be two-level converters or three-level converters, depending on the size of the converter. However, looking at the characteristics in the frequency range of sub-synchronous oscillations, it is the control of the converter that have similar bandwidth. The modulation of the converter, which is different for different topologies, is at a much higher frequency and can therefore be neglected in the study of sub-synchronous oscillations. The control of the converters is different for different applications and must be evaluated separately for each case. When having sub-synchronous oscillations including a VSC, it is often either the PLL or the control of the active or reactive power, for example an AC voltage controller, that is a reason for the amplification of the oscillation. These control loops are designed depending on the application of the converter and can have a wide range of risetimes. Therefore, no general conclusions can be made on frequency intervals where VSCs are especially prone to participate in sub-synchronous oscillations.

When studying the risk of possible oscillation, a first step is usually to make a screening of the VSCs located nearby the synchronous generator. This is made by the unit interference factor (UIF) that gives if the generator and HVDC are large enough and close enough in relation to the grid strength to have a risk of amplified sub-synchronous oscillations. Risk factors for having sub-synchronous oscillations it to have a large synchronous generator close to a large HVDC converter connected to a relatively weak grid.

When having identified the generator and the VSC where there is a risk for oscillations, there are different study methods. There are analytical methods requiring complete knowledge of the system and large computational power. These methods are suitable for research when the system is well specified but is not applicable for studies when for example the VSC is a black-box model or a large system must be considered.

For evaluating larger systems that can also include black box models, frequency scanning methods can be used. For a system including a synchronous generator, the complex torque method can be used and gives the electrical damping seen from the generator. For this method, the damping is given for the whole system and the contribution from the VSC can be seen by comparing the electrical damping with the VSC to the electrical damping without the VSC.

If the electrical damping is low, or negative, at the torsional mode frequencies for the generator shaft, there is a risk for an amplified sub-synchronous oscillation. If the mechanical damping is not known, a time domain simulation can be used to see if there will be any oscillations. Time domain simulations are also useful for including non-linearities in the model and is an important complement to the frequency scanning methods.

Another method for evaluating the risk of sub-synchronous oscillations, that also can be used for oscillations that does not include synchronous generators, is frequency scanning of the admittance/impedance by dynamic simulations. Here, the impedance or admittance is obtained for each frequency and a low or negative resistance at sub-synchronous frequencies indicates a risk of amplified sub-synchronous oscillations.

If there is a high risk of sub-synchronous oscillations, and the performance of the VSC should not be changed, a damping controller can be added. This damping will eliminate the amplification at the specified torsional frequencies. The damping controller is well studied and is used in HVDC converter, which is also specified in the requirements. For wind turbines there are many different suggestions given in literature for damping of oscillations but no general method. The damping controller used for sub-synchronous oscillations between an HVDC VSC and a large synchronous generator is tuned to damp oscillations at the torsional modes which are very well defined. For control interaction between two VSCs, there can be a larger frequency range with negative damping and the damping controller that builds on eliminating amplification at certain frequencies is harder to implement.

There are some factors that influence the risk of SSO. A large synchronous generator and a large VSC compared to the grid strength increase the risk of SSO. Also, if the generator is located close to the VSC there is an increased risk of oscillations.

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Keywords

Sub-synchronous oscillations, sub-synchronous resonance, full power converter wind farms, nuclear power plants, voltage source converters

SUB-SYNCHRONOUS OSCILLATIONS BETWEEN FPC WIND FARMS, VSC-HVDC LINKS AND NUCLEAR POWER PLANTS

Sub-synchronous oscillations between large synchronous generators and voltage source converters, VSCs is an emerging topic with the increased penetration of grid connected VSCs. There are several different study methods used for evaluating the risk for sub-synchronous oscillations.

In this report, the study methods for sub-synchronous oscillations including large synchronous generators and VSCs are evaluated regarding the suitability for different systems. Also, converter design and control are described with focus on the contribution to sub-synchronous oscillations.

It is shown that there are screening methods suitable for finding risks for possible sub-synchronous oscillations. For evaluating the risk of oscillations between a certain synchronous generator and a VSC, there are frequency scanning methods that can be used together with time domain simulations.

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