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AC and DC systems interaction-opportunities and challenges of exchanging system services

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Abstract

Today, the world is facing a situation where only having an energy source is not the final priority, but, also having a clean energy source is the final concern. Where clean energy generation is concerned, only renewable energy resources come into the picture rather than conventional power generation sources. The tendency towards renewable energy sources has grown incredibly in recent years. It can be stated that wind and solar energy sources have the highest share of renewable energy sources. Nowadays, wind farms are usually located far away from load centers. Therefore, strong power transmission systems are required to transmit bulk power over long distances based on AC or DC solutions. Several detailed comparisons have been performed on High Voltage Alternating Current (HVAC) vs High Voltage Direct Current (HVDC) systems. It can be noted that the HVDC transmission system is the more feasible solution to transmit power in renewable energy power systems, especially collecting power from offshore power plants and distributing it among onshore consumers.

Line Commutated Converter (LCC) and Voltage Source Converter (VSC) are two available technologies in HVDC transmission systems. VSC (modern HVDC) technology with Pulse Width Modulation (PWM) has a number of advantages compared to the classical thyristor-based converters, such as the separate and fast-acting controls of active and reactive powers. Hence, VSC is the most suitable converter technology to make a multi-terminal DC (MTDC) power transmission system. It is desired that MTDC systems be capable of interfacing with all types of AC systems since the dynamic of MTDC systems is very fast. The main objectives to construct and use MTDC systems are: the large-scale integration of renewable energy sources into the existing AC grids and the expansion of international energy markets through super grids.

This thesis presents ancillary services from HVDC system and analysis power transmission systems based on VSC technology. The main focus of this thesis is to investigate interactions of AC and DC grids and sharing power between them. A network based on MTDC power transmission system is designed in MATLAB/Simulink by developing a Matlab example to demonstrate interactions between the four AC grids and the MTDC system. In the test model, two AC systems, which are located at two different areas, are transmitting power via two VSCs (rectifiers) to two VSCs (inverters), and the inverters are finally connected to two other AC systems. Dynamic performance of the VSC MTDC system is examined by simulating different conditions to illustrate the energy balance in multi-area grids. Detailed simulations results are presented for normal operation and two case studies with different control strategies, such as active power control and DC voltage droop control to illustrate the behavior of the entire system under different conditions.

Preface

I would like to express my sincere gratitude to my supervisor, Professor Olav Bjarte Fosso of the department of Electric Power Engineering at NTNU for his excellence in supervision, guidance, and providing me the opportunity to be involved in such an interesting subject.

I gratefully thank all my teachers in the department of Electric Power Engineering at NTNU for teaching me to improve my academic studies and to broaden my outlooks related to the engineering studies.

I would also much like to thank my international and Norwegian friends who have treated me kindly and helped me in my academic studies as well as social environment.

Finally, I would like to express my affectionate appreciation my parents, my wife and my daughter for their continuous support, care, love, patience and encouragement.

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Abbreviations

DC	=	Direct Current
AC	=	Alternating Current
HVAC	=	High Voltage Alternating Current
HVDC	=	High Voltage Direct Current
LCC	=	Line Commutated Converter
VSC	=	Voltage Source Converter
PWM	=	Pulse Width Modulation
MTDC	=	Multi-terminal Direct Current
FACTS	=	Flexible AC Transmission System
FDCTS	=	Flexible DC Transmission System
TSO	=	Transmission System Operators
IGBT	=	Insulated Gate Bipolar Transistor
MMC	=	Modular Multilevel Converter
AGC	=	Automatic Generation Control
SCADA	=	Supervisory Control And Data Acquisition
ACE	=	Area Control Error
CS	=	Control Structures
SVC	=	Static Var Compensator
STATCOM	=	Static Synchronous Compensator
ACE	=	Area Control Error
LFC	=	Load Frequency Control
FCNOR	=	Frequency Controlled Normal Operation Reserve
FCDR	=	Frequency Controlled Disturbance Reserves
SCR	=	Short Circuit Ratio
SPWM	=	Sinusoidal Pulse Width Modulation
PCC	=	Point of Common Coupling

Chapter 1

Introduction

1.1 Background

Most of electric power supply systems in the world are widely interconnected. Interconnected grids are mainly chosen for economic reasons, the reduction of cost for electricity, and improved reliability of the power supply. Transmission interconnection systems also provide taking advantage of the diversity of loads, access to sources, and fuel price in order to supply electricity to the loads at minimum cost with a required reliability.

Modern power systems are complex and are expected to support the growing demands of power whenever and wherever required, with suitable quality and costs. The electric power grids are experiencing increased needs for enhanced bulk power transmission capability, reliable integration of large-scale renewable energy sources, and more flexible power flow controllability. However, it has become a challenge to increase power delivery capability and flexibility with conventional AC expansion options in meshed, heavily loaded high voltage AC networks. Also, renewable energy sources have increased the uncertainties in power system operation.

Moreover, both overhead and underground AC grids expansion options are often limited by voltage or transient instability problems, the risk of increased short circuit levels, and impacts of unaccepted network loop flows. Therefore, upgrading power grids with advanced transmission technologies such as HVDC systems and Flexible AC Transmission System (FACTS) devices becomes more attractive in many cases to achieve the needed capacity improvement while satisfying environmental, economic, and technical requirements. Power electronic controllers can effectively solve the problems of expansion of transmission networks. These controllers allow flexible operation of AC transmission systems without stressing the system. Power electronic controllers were first introduced in HVDC transmissions to regulate the power flow and improve system stability.

Based on the experience with large blackouts, strategies for the development of large power systems go clearly in the direction of hybrid transmissions, consisting of AC and DC interconnections, including FACTS when needed. These hybrid interconnected systems can offer significant advantages both technical and in terms of system reliability. Exchanging and sharing the power and required services in the multi-area grids is one of the best advantages which results from AC and DC links for increasing transmission capacity and improving systems stability.

HVDC technology has played an important role in transmission engineering. HVDC transmission technologies have been recognized as effective in several cases such as transmission systems over long distance, bulk power applications, and interconnection of asynchronous AC systems. HVDC links can also strengthen the AC interconnections at the same time, in order to avoid possible dynamic problems which exist in huge interconnections.

In a deregulation market, generation, transmission, and distribution are separated into independent companies. Hence, the relation between the different parts has changed from being non-clear and internal to instead being clear and external communication between various stakeholders [1]. These stakeholders of the energy chain can trade and exchange their products such as energy, ancillary services, and transmission capacity. Ancillary services are all services that Transmission System Operators (TSOs) need to guarantee a specific level of continuity.

1.2 Scope

In the first part of the thesis works, ancillary services from HVDC systems in interconnected grids are analyzed through available literature. Exchange and sharing energy and reserves in multi-area grids are also illustrated. Challenges from HVDC classic (LCC) systems and a comparison with modern HVDC (VSC) systems are investigated.

In the second part of the thesis, a network based on a VSC MTDC transmission system is designed in Matlab/Simulink and the simulation studies provide a demonstration of interactions between AC and DC grids under different conditions, as well as opportunities and challenges.

1.3 Thesis Outline

This thesis is organized into five chapters, and the outline of the work is provided as follows:

- Chapter 1 - Introduction, provides the brief description for the thesis work conducted and transmission systems.
- Chapter 2 Literature Review, explains the brief overview of HVDC technology and ancillary services where HVDC systems can contribute.
- Chapter 3 - Theoretical Background, first, investigation for exchange and sharing energy and reserves in multi-area grids. Next, challenges of traditional HVDC systems

(LCC) vs modern HVDC systems in reactive power/voltage support are presented.

- Chapter 4 Simulation, contains simulations results regarding simulation studies of sharing active power and DC droop control in a network based on a VSC MTDC transmission system.
- Chapter 5 Conclusions and Future Works, gives a review of the project works done in this thesis, describes limitations and suggestions for future works.

Chapter 2

Literature Review

In this chapter, the literature review for HVDC technology is presented briefly to have a general overview in this research area. Ancillary services from HVDC systems are also introduced in this chapter for the readers to be familiar with the background knowledge of this thesis work.

2.1 Electrical Power Systems

Generally, an electrical grid power system can be divided into a generation unit that supplies power, a transmission system that carries power from the generation units to load centers, and a distribution system that feeds power to nearby homes and industries.

Typically, generation units of AC grids are centralized near to load centers to minimize the cost of transportation and storage of fossil fuels and to minimize transmission losses. On the other hand, renewable power generation plants are usually built where renewable energy sources are more available. Today, with the increase in the production and utilization of renewable energy, electrical power systems need a series of requirements in order to optimally use these energy sources.

AC and DC technologies have their own advantages and disadvantages. An engineering analysis is required to find an optimal solution to expand existing transmission networks. The AC transmission system is a well-known technology and the main driving force in industrial and residential areas. Under some conditions, the AC technology is a reliable solution for transmitting high power through overhead lines. Also, DC systems are the better solution for long-distance power transmission via cables and environmental issues. It can be noted that, a mix of both technologies can be helped to the optimal use of their advantages.

2.2 HVDC Technology

HVDC technology has developed to meet a combination of technical and economic considerations. The 20 MW, 100 kV Gotland 1 was the first commercial HVDC link from 1954 in the world. Today, more than several hundred transmission systems have been installed or are in the construction phase around the world. The common advantages of HVDC are: the potential for long-distance transmission, producing an asynchronous interconnection, lower power losses than an HVAC with the same capacity, higher system controllability, increased connected systems stability, improvements to power quality, and less environmental impact. [4].

Converters are the main parts of an HVDC link. As mentioned, LCC and VSC technologies are two available types of HVDC converter. Figures 2.1 and 2.2 show these technologies.

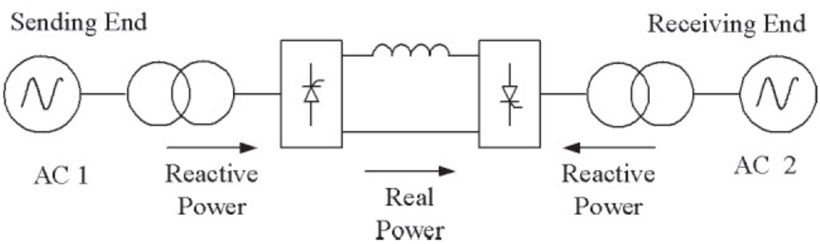

Figure 2.1: LCC HVDC link between two AC systems [5]

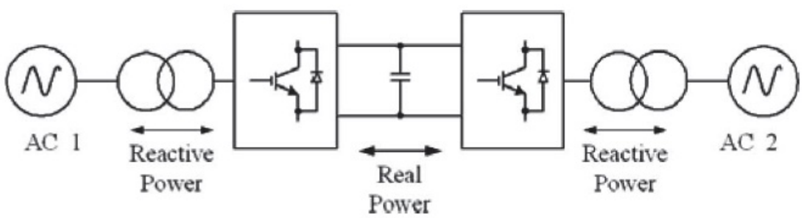

Figure 2.2: VSC HVDC link between two AC systems [5]

2.2.1 Line Commutated Converters

LCCs are based on thyristor technology. A thyristor is a solid-state semiconductor device with four layers of N and P-type material which acts as a bi-stable switch. LCCs need high synchronous voltage sources. Therefore, there is no the capability for a black start operation in this technology. HVDC classic links have had the highest power rating level and voltage level [6].

Controlling the thyristor-based converters are performed by controlling the firing angle of thyristors on both rectifier and inverter sides. The output current can keep at a constant level by injecting a uni-directional line commutated flow of DC current into the AC receiving side. Changing the DC voltage polarity in both stations is the only way for reversing the direction of power. Generally, LCC technology is the mature technology but suitable for transmitting bulk power and the high voltage level with good reliability. According to Ref [4], the main drawbacks of LCCs are as follows:

- High reactive power consumption (50-60% of active power transmitted)
- Sensitive to the strength of AC systems and commutation failures, particularly at inverters.
- Generating AC and DC harmonics on both sides and need to AC and DC filters.

2.2.2 Voltage Source Converters

HVDC classic was the only available HVDC technology until 1997. VSC technology was introduced by ABB to the HVDC transmission market in the experimental Hellsjon project with ± 10 kV and 3 MW. VSCs are based on Insulated Gate Bipolar Transistor (IGBT) valves. In these converters, the current can turn on and turn off at any time independent of the AC voltage.

VSCs operate at high frequency with PWM which allows keeping DC voltages constant in steady-state and normal operation. VSC technology has a high degree of flexibility with the capability to control both active and reactive power independently as shown in Figure 2.3.

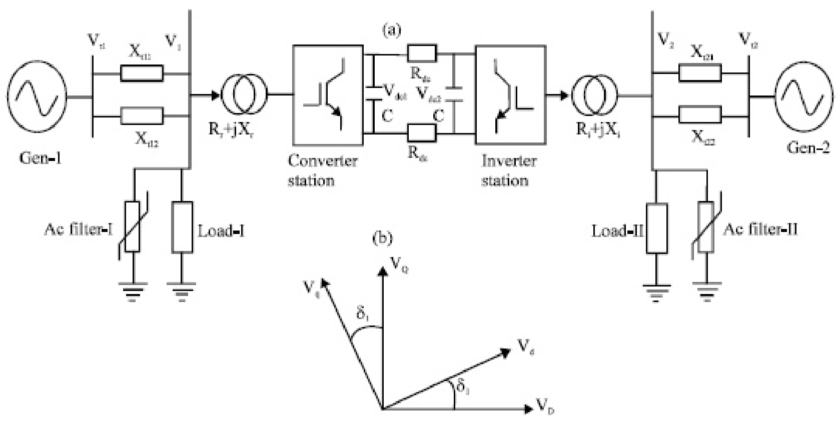

Figure 2.3: Schematic of a transmission system with the VSC HVDC link [7]

Two-level voltage source converters are the first and simplest type of three-phase VSCs. Most of the VSC HVDC links built were based on the two-level voltage source converters. In this type, the voltage at the AC output of each phase is switched between two voltage levels corresponding to the electrical potentials of the positive and negative DC terminals. High harmonic distortion, high transient stresses, and high level of electromagnetic interference are the main disadvantages of two-level VSCs [8]. To improve the poor harmonic performance of the two-level converter, three-level converters have been used in some HVDC links. In three-level voltage source converters, zero voltage level is also added in addition to two levels of voltage.

Modular Multilevel Converter (MMC) is the newest technology of VSCs and now becoming the most common type of VSCs for HVDC links [9]. The MMC technology has higher efficiency, lower harmonic distortion, and fewer components than two-level and three-level VSCs. The overall losses of MMCs are also lower than other types of VSCs, namely around 1% per converter. In this thesis, focus is on the two-level and three-level of VSCs due to the complexity of the MMC technology and the lack of sufficient information.

2.3 Super Grid

Super grid or mega grid is a wide electrical network which crosses national borders. The super grid creates an electricity market to trade across long distances. The history of super grids dates back to the 1960s, when it was first used to unify the Great Britain grid [15].

Network complexity, transmission congestion, rapid diagnostics, and control issues are the main challenges for transmitting huge volumes of electricity through super grids. European grid (UCTE grid) is the largest unified grid between 24 countries. By connecting the European grid to the CIS countries (IPS/UPS grid), this mega grid would span 13 time zones expanding from the Atlantic to the Pacific [16].

2.3.1 AC or DC Super Grid?

HVAC and HVDC technologies have their own advocates. The advocates of HVAC technology believe HVDC links require complex communication and expensive control equipment compared to the simple step-up transformers in HVAC links. They also believe HVAC technology can be an economic solution if there is no limitation to place the transmission lines.

On the other hand, the advocates of HVDC technology believe HVAC technology is not a suitable option to make a super grid due to its disadvantages. Also, offshore renewable energy sources need cable connections which make an AC super grid inappropriate. In addition, environmental issues are so important and there are oppositions against the HVAC carbon footprint due to its destructive effects. Therefore, a mix of AC and DC technology to use the advantages of each technology can be considered as a suitable solution to make a super grid [10].

2.4 Ancillary Services

Transmission System Operators (TSOs) support grids by ancillary services to maintain integrity, stability, and power quality of grids. These services are usually provided by connecting or disconnecting generators, loads and other controllable grid equipment. Some of ancillary services are fixed for grids and some of them are obtained as requirements by TSOs to maintain the power system conditions with respect to operational limits or to recover grids to the normal state in case of disturbance or failure. Some of the main ancillary services are: balancing and frequency control, droop control, voltage/reactive power support, and inertia provision. The rest of this chapter introduces the main ancillary services in power systems.

2.4.1 Definition of Ancillary Services

Today, because of uncertainties and variations of renewable energy sources, power systems need more balancing by controlling the voltage and frequency of grids. Ancillary services are some operational reserved services procured by TSOs to keep a balance between supply and demand, to stabilize transmission systems, and to maintain the power quality on an economical basis in any competitive electricity market environment. Maintaining frequency and voltages within the allowed ranges is one of the main tasks of a power system. In a multi-area network, a system operator can provide ancillary services from other participants in the network due to the price of required services or the inability to provide these support services.

According to EURELECTRIC [17], the definition of ancillary services is:

- All grid support services required by the transmission or distribution system operator to keep the integrity, stability, and power quality of the power system. These support services can provide by connecting or disconnecting generators and other network devices such as controllable loads.

- System services are all services that are provided by a system operator to users connected to the system.

The main categories of grid support services are: frequency support, voltage support, and restoration services. Also, according to the European Network of Transmission System Operators for Electricity (ENTSO-E) [19] division, the main grid support services are: frequency control with different timescales, voltage control, and black start for system restoration. Generally, system operators can manage ancillary services by providing from service producers. The producers of services can add their own share, such as the implementation of controls and load dispatching functions to achieve an appropriate level of security.

There are different ancillary services under the different groups that generators and controllable loads can deliver to system or network operators to support the systems or networks operation. Figure 2.4 shows the delivering procedure of ancillary services from generators. This procedure indicates that in order to provide ancillary services, the system operator must send generators the requirements and capabilities. For example, when the generator is available to provide a service, the system operator sends a request to activate the service while taking into account the situation.

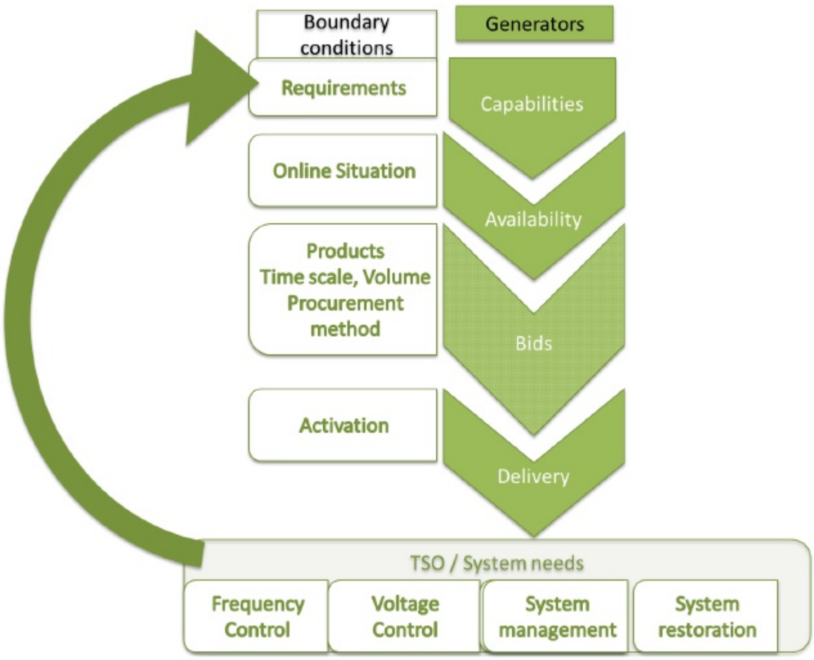

Figure 2.4: Delivering procedure of ancillary services from generators [18]

2.5 Ancillary Services and HVDC Systems

In this section an overview of the different possibilities of HVDC systems with respect to ancillary services is presented. As mentioned before, a mix of HVAC and HVDC systems is an appropriate way to use the advantage of HVDC links that interconnected between two or more HVAC systems. According to Ref [20], there are six types of stakeholders that interface with each other:

- AC grid - AC system operator.
- AC grid - AC equipment.
- AC grid - interface between AC and DC.
- DC grid - DC system operator.
- DC grid - DC equipment.

- DC grid - interface between AC and DC.

Analyzing the six mentioned types is required in order to provide the providers and users of ancillary services in a power system with HVDC links. There are 64 combination forms of these six types. It is possible to ignore 49 of them as not logical and redundant, so only 15 forms are available. Figure 2.5 shows the 6 main combination forms. Dark grey rectangles show equipment that can provide ancillary services, the black arrows indicate some types of ancillary services which are delivered to a grid from equipment, and dashed lines represent borders between control areas.

Each grid can include AC/DC equipment such as generators, converters, transformers, lines, substations, circuit breakers, etc. By analyzing Figure 2.5, one can see that there are four feasible origins to provide ancillary services in a power system with respect to the kinds of grids and equipment. These origins are: ancillary services from AC equipment for AC grids, ancillary services from DC equipment for AC grids, ancillary services from AC equipment for DC grids, and ancillary services from DC equipment for DC grids. Figure 2.6 presents an overview of these four origins. In this thesis focus is on ancillary services from DC equipment for AC grids.

2.6 Ancillary Services from DC Equipment for AC Grids

So far there is no a complete definition of ancillary services from DC equipment for AC grids because some of these services do not exist yet [20]. Therefore, ancillary services provided by DC equipment for AC grids are usually defined on a case-by-case basis for existing DC links. So, the technical configuration is the most important issue to exchange and share the specified ancillary services.

Use of multi-terminal configuration of HVDC links has received much attention. By using MTDC system, we must consider the operation of this system and its interactions with other grids (onshore/offshore stiff, weak, and passive grids). Also, VSC HVDC links are more controllable and can provide ancillary services to AC grids much more than LCC HVDC systems. In a VSC HVDC converter station, the reactive power injection can be controlled without impact on the other converters. Moreover, the active power injection depends on the power flows through the HVDC grid, and can be controlled by DC voltages, DC currents, and voltage/current droops at the converter stations [21].

Figure 2.7 represents an example of a network with five AC areas interconnected by an MTDC system. In this system, only area 1 and area 2 synchronize together. The colored pentagons show the AC areas, the squares are the AC/DC converters, and dark lines are DC transmission lines.

Several ancillary services are reviewed and explained in the available literature. Ref [21] addressed balancing and frequency control, voltage/reactive power control, and rotor angle stability-related control that each service can be divided into few subgroups. In addition, ENTSO-E also provided a draft list of ancillary services such as active power

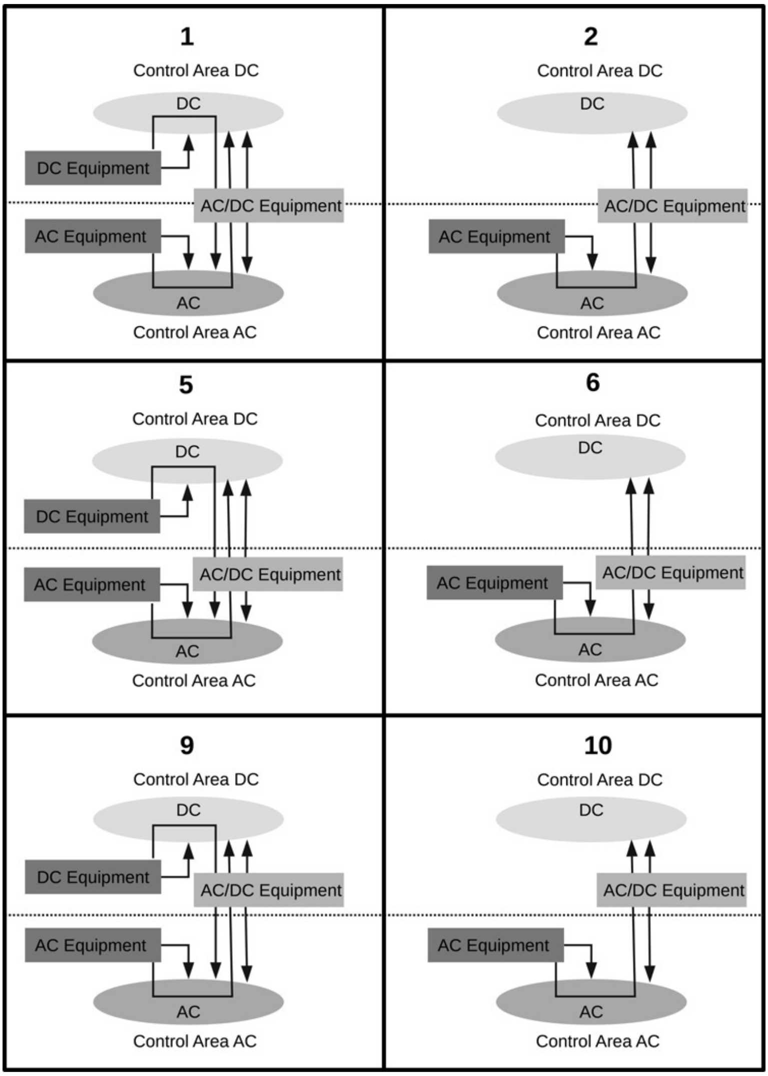

Figure 2.5: Different possible combinations of stakeholders that interface with each other [20]

control and frequency support, reactive power control and voltage support, short-circuit power, power oscillation damping capability, and black start capability [19]. Some of the most important ancillary services are explained in the following.

2.6.1 Balancing and Frequency Control

Frequency is the number of occurrences of a repeating event per unit of time. In cyclical processes, the frequency is defined as a number of cycles per unit time. Generally in a power system, when total generation is greater than customer demand and the net power is

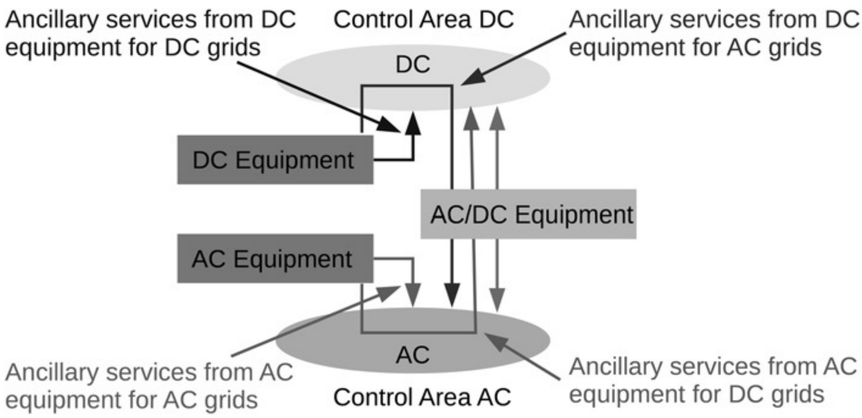

Figure 2.6: Overview of four origins to provide ancillary services in a power system [20]

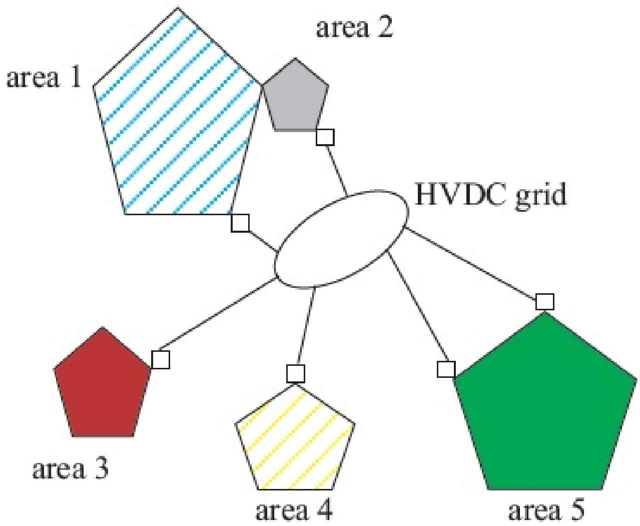

Figure 2.7: Example of a network with five AC areas interconnected by an MTDC system [21]

in a surplus, the system frequency increases and be greater than the target value (normally 50/60 Hz). Conversely, the system frequency decreases when the net power is in a shortage. The energy balance is one of the main considerations in power systems.

The system balance is initially the restored point between total load plus losses and power generated (Figure 2.8). By varying the load, the generator governor changes the output of the generator in response to frequency changes. A higher amount of the target value of the system frequency leads to more energy consumption in some system devices like electric motors. Balancing authorities have the responsibility for matching (balancing) the electric loads and total power generation. They can achieve the load-generation balance by connecting or disconnecting generators and controllable loads in systems.

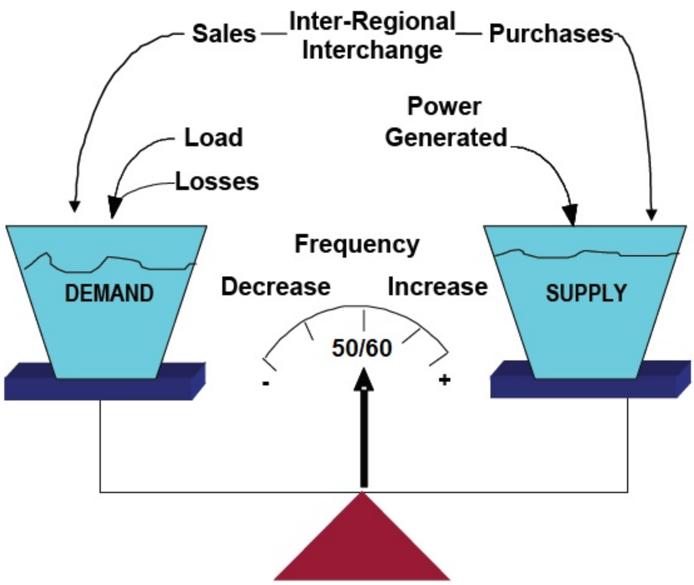

Figure 2.8: Demand- Supply balance [22]

When an HVDC link is used to interconnect AC areas together, if there are adequate operational margins, the HVDC link can adjust the power flows. When occurring disturbances in the AC areas, The MTDC system can solve problems by adjusting the power injections with respect to the target values of system frequencies in the AC areas.

In AC systems, frequency control is usually based on hierarchical methods. The balancing and frequency control are performed over a sequence of time by using different resources [23]. Figure 2.9 shows the sequence of balancing and frequency control.

Primary Control

Primary control or frequency response is usually performed in a few seconds after changing the system frequency to stabilize interconnected systems. The primary control is provided by governor action and load. After sensing any change in the generator speed, the governor adjusts the input with consideration to changes into the prime mover on the generator. Under-frequency relays can also quickly decouple loads from the system by the automatic operation. These relays can disconnect predefined loads in a few seconds to bring the system frequency to the target value. Reduction in the loads may be under a contract or a part of ancillary services to ensure the system stabilization after any disturbances occur in the system.

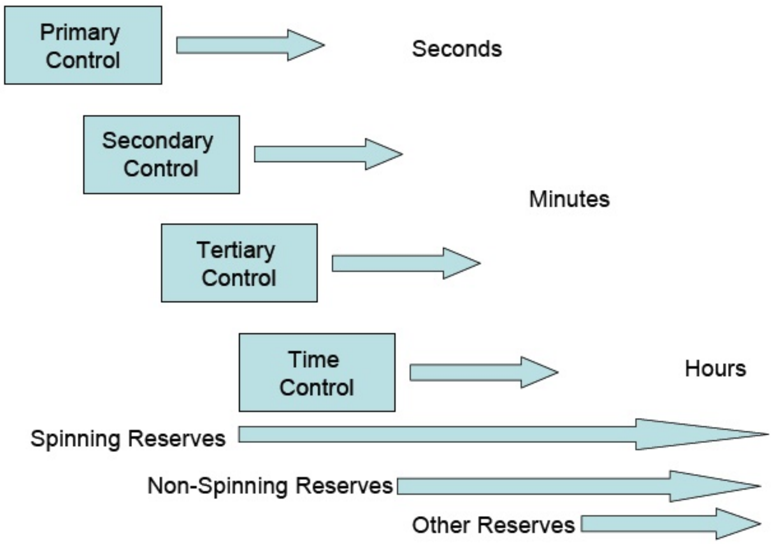

Figure 2.9: Sequence of balancing and frequency control [22]

Losing the generator or generators is the most common type of disturbance that leads to a reduction in the system frequency (target value). Typically, determining the available amount of frequency response (primary control) depends on the spinning reserve in the interconnection systems. The main duty of the primary control is to stabilize the system frequency (not return to the target value). Other control components have responsibilities to restore the system frequency to the normal condition.

Primary HVDC control also takes a few seconds to share primary system reserves between AC areas in a network. The primary system reserves are the additional amount of power that each area can inject within a few seconds to other areas. Ref [21] indicated, there are two alternatives to share primary system reserves between areas: sharing reserves at all time and sharing reserves only during emergency situations. The practical implementation of primary HVDC control is based on local control and measurements of the system state, taking into account the reference value of the control variable, and the associated operational constraints to avoid delay and reliability issues related to communication [21].

Secondary Control

Secondary control is performed in the minutes time frame and contains the balancing services and initial reserve. Even though the time frame for this type of control is minutes, some of the resources can be faster to respond. The secondary control is performed by balancing authorities through computer control such as load-frequency control and Automatic Generation Control (AGC). In the other words, the secondary control is used to return the system frequency to its target value after disturbances occur.

The AGC method is the most common method to perform secondary control. This method executes in conjunction with Supervisory Control And Data Acquisition (SCADA) systems. In power systems, SCADA systems are usually used to collect all information about power systems, such as the system frequency, outputs of generators, and interchanged data between the system and other adjacent systems.

By using AGC method, the system can determine Area Control Error (ACE) of a balancing area. The ACE index of a system indicates whether the system is in balance or not. In the AGC method, the software automatically determines the economic output to generate resources and sends setpoints to the generators with consideration of the system ACE index. The secondary control may also be used to smooth variations of a long-term setpoint to another setpoint.

2.6.2 Droop Control

It is expected that MTDC systems are applied to utilize DC voltage droop control. The system reliability is a decisive aspect of the operation of MTDC systems because each malfunction has a considerable economic impact. Ref [24] noted, ”it should be avoided that the regulation of the DC voltage and the intertwined regulation of the power flow between the terminals should rely on an approach where one single unit is assigned a dominant role. Instead, a distributed control architecture where multiple units are actively participating in the control of the grid based on local measurements is preferable”.

There are several strategies for DC voltage droop control in the available literature. The mechanism of DC voltage droop control is the common point in most of these strategies. Use of diverse control objectives and different feedback signals can have a significant impact on the dynamic performances. To analyze different control schemes of droop control requires a classification DC voltage droop control implementations in MTDC systems.

Classification DC Voltage Droop Controllers in MTDC

Generally, a droop control scheme presents a linear equation between two electrical variables as equation 2.1:

$$(y - y*) = k_{droop}(x - x*) \tag{2.1}$$

Where x and y are the measured electrical variables, x* and y* are the initial set points, and k_{droop} is the droop gain. In the specific case, DC voltage droop control in an MTDC system as equation 2.2:

$$(V_{DC} - V_{DC*}) = k_{droop}(x - x*) \tag{2.2}$$

The second electric variable (x) is usually active power or current [25]. Both active power and current can refer to AC or DC sides of converters. There are two different types of generalized structures which depend on the loop of using DC voltage. In type 1, DC voltage is used in the second loop and in type 2, it is used in the first loop. Figure 2.10

shows the two general types of droop control structures.

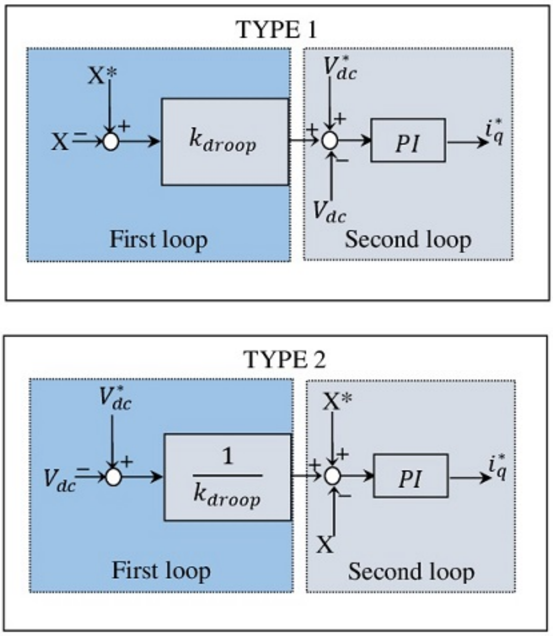

Figure 2.10: General types of droop control structures, data from [26].

There are four options for the second electrical variable. These options are: P_{AC} (active power on the AC side), P_{DC} (power on the DC side), I_{AC} (active component of the current on the AC side), and I_{DC} (the current on the DC side). Figure 2.11 presents these options and the overview of DC voltage droop controllers.

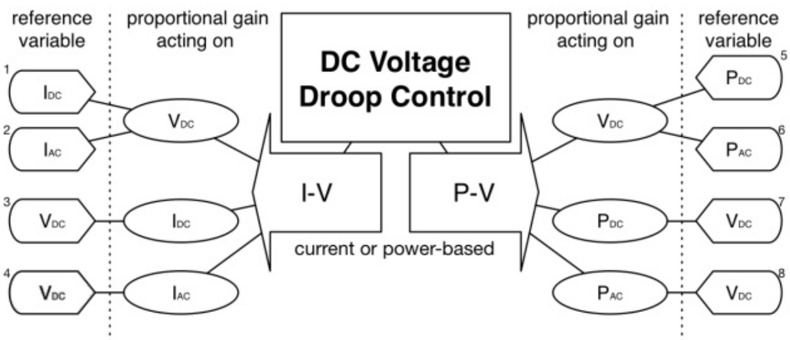

Figure 2.11: Overview of DC voltage droop controllers [24]

Depending on whether the DC voltage is used (within the first loop or the second loop) and on which electric variable the proportional gain is acting, leads to 8 different DC voltage droop Control Structures (CS). Figure 2.12 shows these 8 different DC voltage droop control structures. All of the control structures have the similar principle of operation and their steady-state can be almost similar if the droop gain is scaled correctly. However, the dynamic performances and the stability ranges of the control structures are different. These 8 DC voltage droop control structures are as follows:

- CS1 ($V_{DC} - I_{DC}$) [27, 28]
- CS2 ($V_{DC} - I_{AC}$) [29, 30]
- CS3 ($I_{DC} - V_{DC}$) [31, 32]
- CS4 ($I_{AC} - V_{DC}$) [24]
- CS5 ($V_{DC} - P_{DC}$) [33, 34]
- CS6 ($V_{DC} - P_{AC}$) [33]
- CS7 ($P_{DC} - V_{DC}$) [35]
- CS8 ($P_{AC} - V_{DC}$) [35]

Multi-terminal network Droop Control

A typical multi-terminal network is illustrated in Figure 2.13. This multi-terminal network consist of the main AC grids, the MTDC system, the wind farm grids. The wind farm converters operate as power sources and the AC grid-side converters as loads. Controlling the AC grid-side converters attempts to maintain DC voltage level by sharing available active power among them. When voltage faults occur in the AC grids, the wind farm converters act in voltage regulation mode and the AC grid-side converters extract the maximum power possible without regulating the DC voltage [37].

Droop control is employed to regulate DC voltage through the technique that provides the power distribution among different terminals without communications. Usually, the control of each converter performs on two levels: an inner and outer loops. The inner loop is in charge of controlling currents and the outer loop has the responsibility to regulate DC voltage. Droop control operates on the outer loop to impose the reference current ($i*$) to the inner loop. Figure 2.14 illustrates the droop control of a VSC HVDC link. The control law is given by equation 2.3, where $i*$ is the reference current, E is the DC voltage, E_0 is the DC reference voltage, and k_{droop} is the droop gain.

$$i* = k_{droop}(E - E_0) \tag{2.3}$$

The dynamics of the current loop can be much faster than the outer loop. Hence, the reference current can be supposed to be equal to DC current (i) of converter. To choose

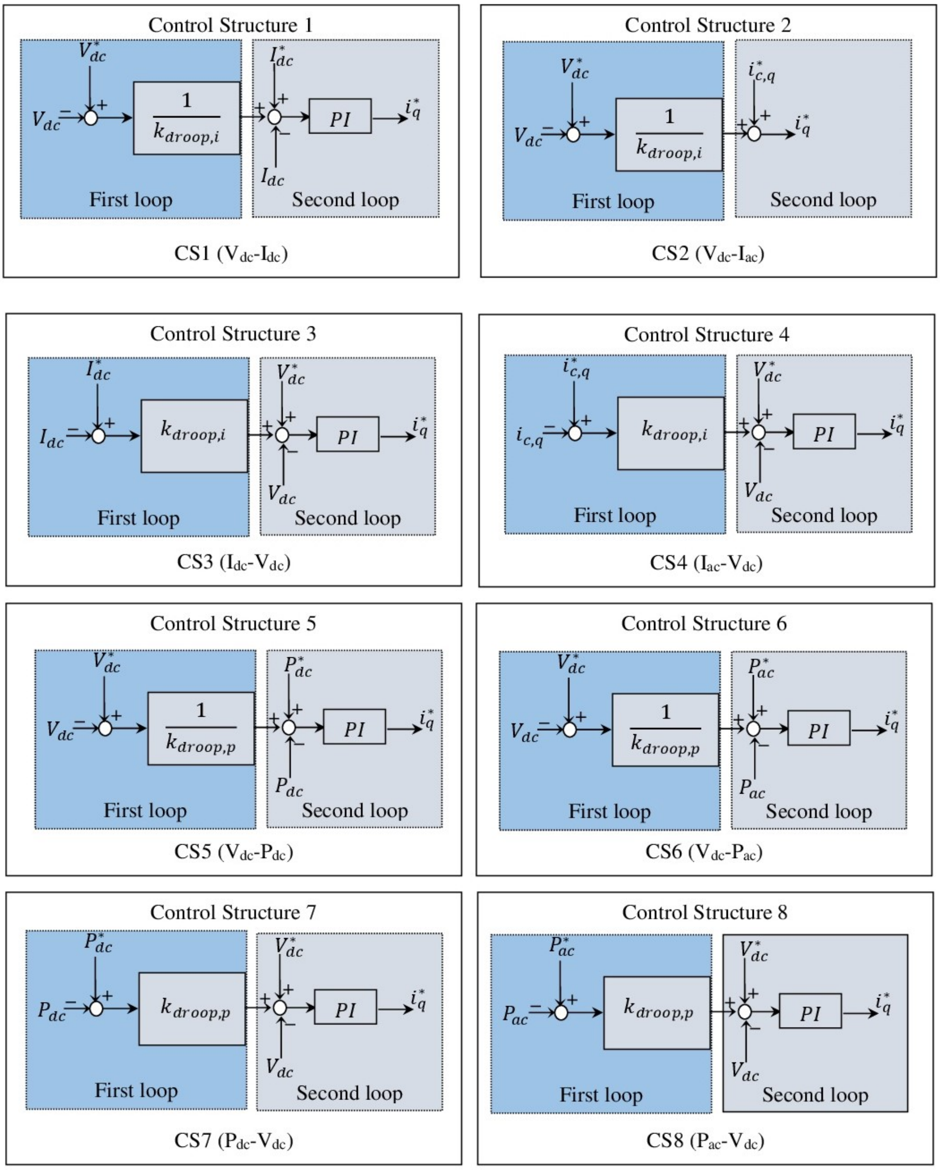

Figure 2.12: DC voltage droop control structures, data from [26]

the droop gain (k_{droop}) for each converter the entire behavior of multi-terminal networks should be considered. It can be noted, each local controller can affect on the global stability of the network and DC voltages in other terminals. Therefore, the selection of the droop gain must be addressed in the context of multi-variable system theory [37].

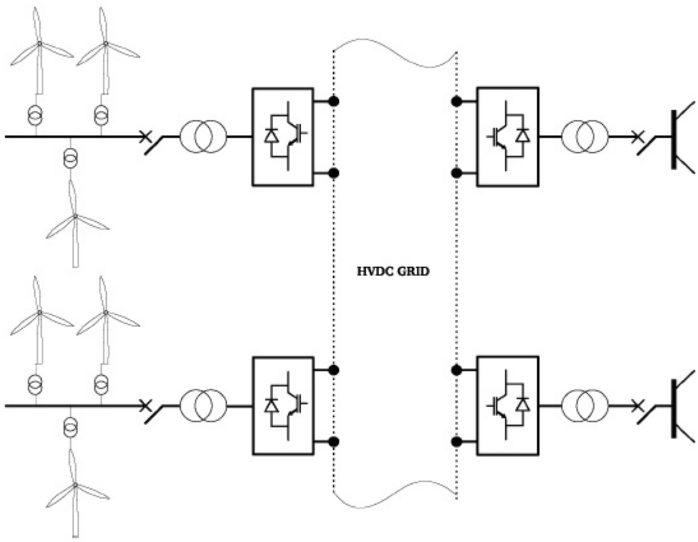

Figure 2.13: Typical multi-terminal network [37]

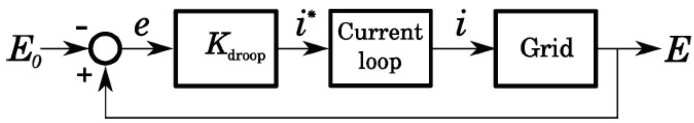

Figure 2.14: Droop control scheme of a VSC HVDC link [37]

Ref [38] provided the mathematical representation of control objective in terms of droop characteristics. It also explained basic and advanced converter control strategies, and basic and advance grid control strategies.

2.6.3 Reactive Power/Voltage Support

As mentioned previously, reactive power/voltage support is one of the main ancillary services. Reactive power is critical to maintaining voltage levels and it can make up the basic components required for open access operation of electric power transmission systems. The optimal allocation and size of reactive power sources are most important for the system operation and for reducing total losses. Typically, transmission customers must pay for reactive power support service based on power factor penalties. Generally, power systems with low power factors need more reactive power support.

In an open access environment, TSOs are responsible for coordinating the reactive power service [39]. Keeping constant the customer voltage is one of the key aspects of electric power services. Keeping voltage levels in a power system is performed through several primary mechanisms such as generator excitation systems, tap changing under load transformers, and capacitor banks.

It is essential to supply reactive power in a short distance away from where reactive power is required due to its high losses. There are several resources to supply reactive power such as shunt capacitors, synchronous condensers, synchronous generators, and static VAR compensators. How quickly reactive power is supplied is important, as is how rapidly a generating unit supply reactive power can respond to a signal calling for reactive power support [40].

Why Does Reactive Power Matter?

Power is the algebraic expression of voltage and current. Almost all the equipment produces and/or consumes active and reactive powers in AC transmission systems. Active power does useful work such as runs motors and lights lamps. On the other hand, reactive power does not do any work. In a power system, reactive power maintains voltages level and controls the system reliability. Positive or negative sign of reactive power depends on current peaks toward voltage peaks. Voltage magnitude increases during producing reactive power and it decreases during consuming.

The control of the system voltage is necessary to keep equipment safe and to prevent damages like overheating. In brief, when a system tries to supply more loads than the system ability, the reduction of reactive power leads to a voltage collapse in the system. Usually, the system current also increases during the voltage drops to maintain power in the system. Increasing the system current leads to consuming more reactive power, and as a result, it worsens the voltage drop. Generally, if a power system cannot supply the required reactive power, an uncontrollable reduction occurs in the system voltage.

Determining the reactive power requirement in a system requires three processes: engineering, economics, and judgment. The engineering process requires complex mathematical computer models to simulate the system in various situations. To analyze the economic process requires setting costs or bids into the models to achieve an effective and reliable system. The judgment process is necessary to determine the reactive power requirement of the system because many modeling choices, assumptions, and approximations are available [41].

Several devices in a power system can contribute to produce and/or consume the reactive power/voltage support. The most important of these devices are generators, capacitors, and transmission lines. Generators can produce and consume both active and reactive power. Usually, generators have an instantaneous response and the highest amount of reactive power when the system requires reactive power. Capacitors produce reactive power. AC transmission lines have different behaviors under different conditions due to their physical characteristics. A transmission line can produce reactive power under the light loading condition and consume reactive power under the heavy loading condition [41].

Some Properties of the Problem

Reactive power/Voltage support is more complex than the active power support and frequency control. This complexity is due to changing voltage magnitudes in steady-state with the bus location, but frequency is the same everywhere in steady-state [42]. Frequency deviations can be control at any location in the system. Active power transmission losses also depend on the distance between the place where the mismatch is made and the place where that it is compensated.

Reactive power cannot be transmitted over long distances due to high losses. High losses of reactive power is another reason for the complexity of the reactive power/voltage support. Voltage collapse is the basic problem in the case of delivering reactive power over long distances from power plants. This problem needs systematic approaches in order to prevent it. The meaning of reactive power balancing in a power system is the reactive power injected at each bus must be equal to reactive power sent from the same bus into the system. The reactive power balancing is the key element in the maintaining voltage, synchronous stability, and appropriate power system performance [42]. It is obvious the generation and transmission of active power without considering the generation and transmission of reactive power is not possible.

Physical Characteristics of Reactive Power in AC Systems

As mentioned before, reactive power is a characteristic attribute of the generation, transmission, and distribution of electricity. Most of electric power loads are inductive in nature such as induction motors and transformers that usually consume reactive power. AC overhead transmission lines and underground cables have both inductive and capacitive parts. Therefore, supplying or consuming the reactive power of the overhead lines and underground cables depends on their loading condition.

To have an effective power system, reactive power must be managed to meet demand. Instability and abnormal voltages in systems are considerable problems if reactive power is not correctly managed. Both inductors and capacitors can be installed in power systems to keep the system voltage in an allowable range and have the effective operation. There are several methods for efficient and effective management of the reactive power compensation. Some of these methods are: predictable changes in load demands and generation balances, scheduled generation, transmission outages, and contingencies [41].

Inductors and capacitors are the static reactive power devices because they do not have the ability to actively control the reactive power output in response to any changes in the system voltages. On the other hand, synchronous generators, synchronous condensers, and FACTS devices are the dynamic reactive power devices since they can control and change their reactive power output into allowable ranges in response to any changes in the system voltages.

Synchronous generators are connected to the grids and operated synchronously at the same frequency. Generally, generators can produce the combination of both active and reactive powers by their setting. The balance of active and reactive powers in the generators is related to their capability and limits. Typically, thermal limits of a generator determine its reactive power capacity.

Some of old wind generators only consume reactive power from grids. Newer models can provide reactive power and have a selectable range for power factor from 0.9 lagging to 0.95 leading. Today, a number of wind farms use Dynamic Var (D-var) control systems to optimize the state of the local system to improve grids reliability. D-var stabilizes and regulates the voltage and power factor on transmission and distribution systems. Typically, power from wind farms transmits over long distances due to the locations of most of them. Therefore, D-var systems are suitable to mitigate voltage irregularities at the point of interconnection between wind farms and grids.

Synchronous condensers (synchronous compensator) are DC-excited synchronous motors. These condensers can generate or absorb reactive power to adjust the system voltage or to improve power factor. Usually, using the synchronous condensers is more economical than using the synchronous generators.

As previously pointed out, FACTS devices can help to control power flows and increase the stability of transmission systems. There are several types of FACTS devices to manage reactive power such as Static Var Compensator (SVC) and Static Synchronous Compensator (STATCOM). Basically, SVCs consist of shunt reactors or shunt capacitors that are connected to power systems via thyristors. SVCs can generate or absorb reactive power to adjust the system voltage. The operation of STATCOM devices is like the synchronous condensers' operation without the spinning inertia. STATCOM devices are more effective than SVCs or capacitors during voltage fluctuations in the system. In a STATCOM device, microprocessors automatically adjust bus voltages within an allowable range.

Reactive Power/Voltage Support from HVDC system

The reactive power consumption is almost zero on DC transmission lines since the frequency is zero Hz in DC systems. However, converters need reactive power which its amount dependant on the type of converters and the power rating of the converter terminals. In HVDC links with converter transformers, shunt capacitors, and filters, the transformers require reactive power to maintain AC voltage within an allowable range on the AC side of the converters. Shunt capacitors and filters can generate and supply a part of the reactive power requirement depending on their capacity. So, sufficient reactive power compensation is the critical issue in HVDC links' design.

The modern HVDC converters can supply reactive power and also control AC bus voltages by a master controller. This service is used to improve the power quality by covering the flicker control. Generally, a VSC HVDC link can control the active power transfer accurately. Thereby, modern HVDC links can control voltage and frequency of the AC side of their converters from converter stations. This feature is used for the black start capability by controlling voltage and frequency from zero to nominal values and it is very useful in case of HVDC link interconnection between AC weak grids.

So far, modern HVDC links have common controls and special controls in their network environments. These HVDC links can provide ancillary services to connected AC grids. For example, the Gotland HVDC light system (VSC)controls the AC grid's voltages that connected. This control is performed by reactive power support. In addition, AC bus voltages also can keep constant by ordering reactive current. The speed of this procedure is around 3 Hz, by this speed, the Gotland HVDC light system is able to control transients, flicker, and maintain its AC bus voltages constant [43].

2.6.4 Inertia Provision

Inertia is one of the most basic concepts of physics. In general, inertia is defined as the resistance of a physical object to a change in its state of motion, including changes in its speed and direction [44]. The inertia in the rotating masses of synchronous generators and turbines determines the immediate frequency response to inequalities in the overall power balance. Usually, systems can handle small changes and the rotating masses inject or absorb kinetic energy into or from the grid to neutralize the frequency deviation. Traditional power plants have had spinning parts that can rotate faster or slower to support the balance between supply and demand. This is thanks to the inertia concept. Hence, when inertia is not enough in a system, the system cannot absorb frequency fluctuations and it gets too high or too low.

Renewable energy generation units interact with grids in a fundamentally different way than traditional plants. These renewable plants are in general connected through power electronic converters which can be decouple fully or partly generators from grids. Then, the available links between the rotational speed of generators and the grids' frequency is removed. These converters that were connected to generation units, udo not inherently contribute to the total system inertia [45]. Controlling converters that decouple generators from grids is managed in a way with the lowest effect on variations in grids frequency. This control method can exchange energy with grids. This energy exchange with grids is called the virtual or synthetic inertial response. The virtual inertial response is characterized by the virtual moment of inertia J_V. Figure 2.15 shows a basic virtual controller that represents the kinetic energy exchange of synchronous generation units.

Figure 2.16 and Figure 2.17 represent schematically the exchanged and stored energy in a power system directly after a power imbalance and its influence in the system frequency, respectively. In Figure 2.16, each block schematically shows a type of power system. The blocks (A), (B), and (C) are respectively: a traditional power system, a power system with renewable generation units and power electronics converters without virtual inertia, and a power system with renewable generation units and power electronics converters with virtual inertia. The width and height of each block are proportional to $\sum J_{SG}$ and $\frac{W_e^2}{2}$, respectively.

In addition, the gray area states the stored kinetic energy at the nominal frequency

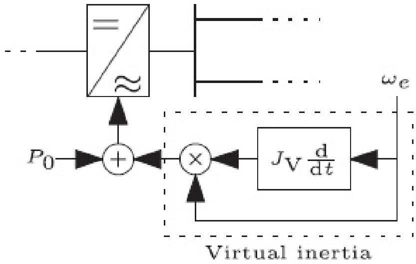

Figure 2.15: Virtual inertia controller [45]

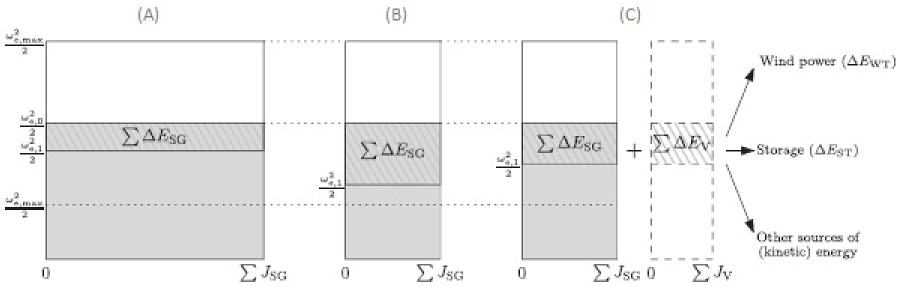

Figure 2.16: Schematic of kinetic energy exchange [45]

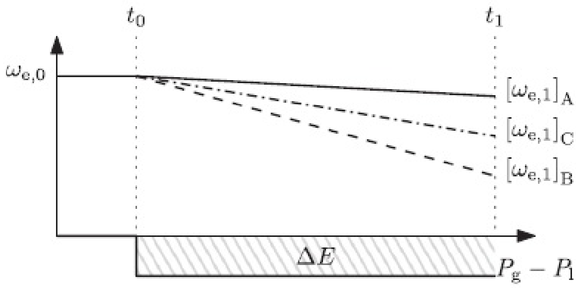

Figure 2.17: Influence of the exchanged and stored energy in the system frequency [45]

($w_{e,0}$), because power systems are designed to operate within a specific frequency range. The stored kinetic energy must be varied between the boundaries ($w_{e,min}$ and $w_{e,max}$). For example, when an imbalance occurs in system A (the traditional power system), the kinetic energy from the conventional generation units initially compensates the deficit, which is called the inertial response of the system. The amount of the inertial response is illustrated by the hatched areas. As a result of a imbalance, the system frequency decreases and reaches to $[w_{e,1}]_A$ at time t_1. Figure 2.17 also indicates that the exchanged energy (ΔE) is a function of time. The frequency drop can be arrested by increasing power from the power set points of generation units. Otherwise, the stored kinetic energy is depleted and the system will collapse.

The energy exchange is restricted limitations such as converter operating limits, minimum rotor speeds, maximum deceleration and acceleration of the blades, and high dependencies on the operating point [45]. As shown in Figure 2.17, the power system with converters that participate in partially compensating the reduction in synchronous inertia by delivering the virtual inertial response (system C), will have the lower frequency deviation ($[w_{e,1}]_C$ at time t_1) compared to the power system without the virtual inertial response and without responding to frequency changes (system B) at the same time (t_1).

As mentioned before, power electronic converters can prevent the contribution of kinetic energy stored in renewable energy sources from combining with the grids inertia. In the case of wind energy, there is a considerable amount of kinetic energy stored in: wind turbines, the rotating mass of their blades, and the gearbox. By equation 2.4 can obtain the kinetic energy stored in the rotating mass of wind turbine blades. J and ω are the inertia of the wind rotor and the rotor speed, respectively. There is another index that called the inertia constant (H) which is given by equation 2.5, where S is apparent power.

$$E = \frac{1}{2}J\omega^2 \tag{2.4}$$

$$H = \frac{E}{S} \tag{2.5}$$

The inertia constant is the time duration that a generator provides the nominal power by applying its kinetic energy. The typical range of inertia constant for generators in the power plants is 2-9 seconds and in wind turbines is 2-6 seconds [46]. Therefore, using wind turbines in power systems does not necessarily reduce the amount of available kinetic energy. According to Ref [47], the control of inertia must be performed within a few tens of milliseconds.

Generally, large wind farms must be operated with reserves to improve frequency response. A larger inertia means a smaller transient frequency deviation of the system frequency during disturbances. A power system with an inertia-control loop can have poor damping. Ref [49] illustrated a control scheme to provide electrical inertia by HVDC converters and the effects of the inertia-control loop.

Chapter 3

Theoretical Background

In the previous chapter, the literature review, related to HVDC technology and ancillary services from HVDC systems, is discussed briefly to cover a general understanding of methodologies in this research area. In this chapter, the theoretical background is investigated for exchange and sharing reserves in multi-area grids. Also, challenges of LCC HVDC systems in reactive power/voltage support is presented.

3.1 Reserves in Multi-Area Grids

In a power system, the possibility of random failure of main components, as well as the unpredictable behavior of the demand, necessitates the introduction of energy reserves as a way of reducing the risk of blackouts. The study of operational reserves in electric power systems has taken special importance in recent years due to the growing penetration of renewable energy sources with variable nature. Nowadays, by fast developing the integration of power markets and renewable energy sources, the exchange of balancing services between areas is an important topic for research.

Renewable energy sources usually have limited predictability and alternative generation profiles. Therefore, base-load grids with these energy sources are required to market arrangements, additional balancing, and reserves in generation and consumption. The main targets of the balancing and exchange power reserves are: to maintain frequency and time deviation within an allowable range, to keep the balance of areas within limits, and to adjust the balance on each side of a congested line or intersection.

3.1.1 Operational Reserves: Definition and Different Accepts According to Markets

Operating reserves are available generating capacities in electricity networks that TSOs can use within a short interval of time to meet the demand during disruptions to the supply. Power systems need to maintain a certain amount of operating reserves to avoid power shortage due to generator failures, load oscillations, and other contingencies. In most of power systems, the operating reserve is greater than the capacity of the largest generator and a fraction of the peak load [50].

Operating reserves can be characterized by their response speed, response duration, frequency of use, direction of use (up or down), and type of control. Generally, some of operating reserves are used to respond to the routine variability in generations and/or loads. Other operating reserves are required to respond to unexpected events. Operating reserves can be classified based on whether they are deployed during non-event (normal) conditions or event conditions. Non-event conditions can be based on both variability and uncertainty, however, there are occurrences that continuously taking place. Event conditions can be based on whether they can be predicted or not.

There are a number of different ways to classify operating reserves. Figure 3.1 shows one of classifications of operating reserves categories. In this classification, both non-event and event response categories can be subdivided based on the required response speed. Some events are instantaneous and some of them take time to occur. Generally, instantaneous events require autonomous response to arrest frequency deviations. Then the system frequency must be corrected back to its target value and the systems Area Control Error (ACE) must be reduced to zero during instantaneous and non-instantaneous events.

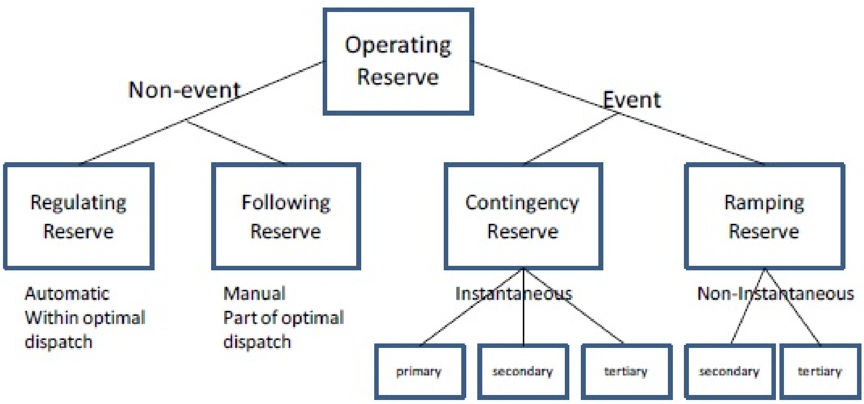

Figure 3.1: Classification of operating reserves categories [51]

The tree in Figure 3.1 illustrates how different types of operating reserves relate to each other. Event conditions include things that are severe and infrequent and non-event conditions are continuous events that occur often. Non-event reserves are separated by their speed into regulating reserves being faster and following reserves being slower. The speed that separates these reserves varies from system to system. Regulating reserves are usually used to correct the current imbalance and act automatically within the shortest optimal dispatch or market clearing interval. Following reserves are used to correct the anticipated imbalance and act as part of the optimal dispatch or market clearing interval.

Event reserves are also separated by their speed. These reserves can be classified into contingency reserves and ramping reserves. The speed that separates these two reserves is whether they are used for instantaneous events or non-instantaneous events. Contingency reserves can be subdivided into primary reserves, secondary reserves, and tertiary reserves. As explained in balancing and frequency control section, primary reserves must be automatically responsive in tens of seconds to events to make sure that frequency deviations are arrested and maintain the system balance. Secondary reserves are deployed in a few minutes to return the system frequency to its target value. Finally, tertiary reserves help to replenish the primary and secondary reserves that were deployed for events. The response time for tertiary reserves is tens of minutes.

Also, ramping reserves can be subdivided into secondary reserves and tertiary reserves. These types of reserves does not need the primary reserves (the automatic frequency response) due to the speed of the non-instantaneous events. Secondary reserves are deployed to correct the system frequency or ACE. Tertiary reserves are essential and used to support against future events that may occur in the same direction. The full response time for these reserves may be different than the subcategories of contingency reserves.

In addition, there are two main classifications for reserves in international electricity markets. These classifications are: American and European classifications. Definition of American reserves is defined by National Renewable Energy Laboratory (NREL) and based on the specific function. The American classification can be subdivided into five subcategories as follows:

- Frequency Responsive Reserves. Automatically respond to active power imbalance and stabilizes system frequency.
- Regulating Reserves. Capacity available during normal conditions for assistance in active power balance to correct the current imbalance that occurs.
- Ramping Reserves. Capacity available for assistance in active power balance during rare events that are more severe.
- Load Following Reserves. Capacity available during normal conditions for assistance in active power balance to correct future anticipated and non-random disturbances.
- Supplemental Reserves. Capacity available to restore the level of reserves to before the occurrence of events.

On the other hand, the European classification is based on the full response time and can be subdivided into three subcategories as follows:

- Primary Reserves. These reserves can be provided by generators with a governor that can respond rapidly. The generators are capable of automatically detecting fluctuations in the system frequency and adjusting their production to maintain the frequency. The full response time in this type is usually from 0 to 30 seconds.

- Secondary Reserves. These types of reserves has continuous and automatic activation. The secondary reserves response is required to return the system frequency to its target value. The full response time in this type is between 30 seconds and 15 minutes and can stay active for as long as necessary.

- Tertiary Reserves. These reserves are manually activated and respond to a significant imbalance in a control area. Also, the tertiary reserves are used to help in replacing the primary and secondary reserves. The full response time is normally up to 15 minutes.

Moreover, spinning and non-spinning reserves are often discussed in combination with operating reserves. Spinning reserves are the capacity of online reserves that are synchronized to grids and ready to meet electric demand within 10 minutes of a dispatch instruction by TSOs. Non-spinning reserves consist of offline generation capacity that can be ramped to capacity and synchronized to grids within 10 minutes of a dispatch instruction by TSOs. Non-spinning reserves are capable to maintain grids outputs for at least two hours. Both spinning reserves and non-spinning reserves are required to maintain the system frequency during emergency conditions [53]. Figure 4.1 indicates the full response times of reserves in the American and European classifications.

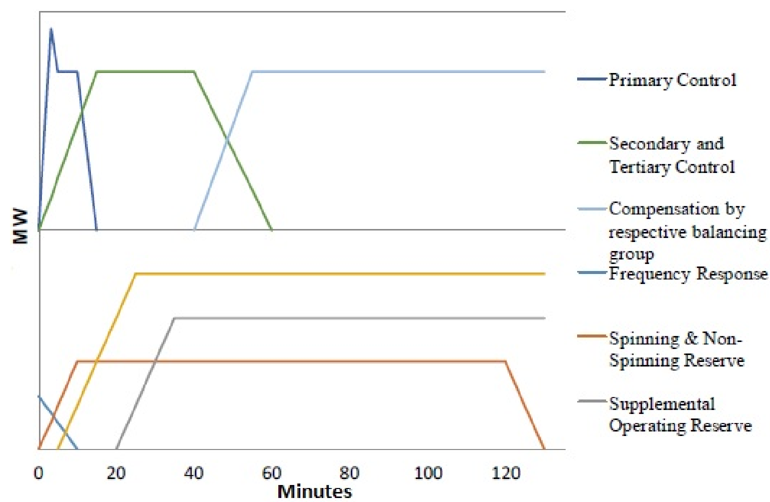

Figure 3.2: Response times of reserves and comparison between the American and European classifications [52]

3.1.2 Imbalance Definition

Three major types of imbalances in the balance management are: power deviation, regional/area imbalance, and settlement imbalance.

- Power deviation is the difference between generation and consumption. This type of imbalance causes a deviation in the system frequency and leads to the primary control activation.

- Regional/Area imbalance is a deviation from exchange plans in the specific balancing area. In a large synchronous network that consists of different balancing areas, maintaining the energy balance is important. Furthermore, responsibilities must be shared among the different balancing areas and support each other via different reserves.

- Settlement imbalance is the same as the regional/area imbalance and a deviation from exchange plans, but on average over the settlement period (MWh/period). The settlement period can be 15, 30 or 60 minutes.

3.1.3 Energy and Reserve Dispatch in Multi-Area Grids

Energy is the main product being exchanged and/or shared in an electricity market. In a competitive market, producers and consumers participate by submitting offers to sell and/or bids to buy for market operators. Market participants also can send bids to provide ancillary services similar to the energy supply. The market operators would dispatch energy bids and other types of bids according to applicable market rules [56].

There are several methods to dispatch energy and reserves in multi-area grids. Before analyzing these methods, the general functional requirements for physical market dispatch must be indicated. According to Ref [58], inter-zonal trading and network congestion management are the functional requirements to dispatch energy and reserves.

Inter-Zonal Energy and Reserves Trading

- The conservation of energy within each zone is the balance of generation, demand, interchange, and losses.

- Reserve requirements for each zone must be met through a combination of local and imported reserve offers.

- Physical dispatch of energy and reserves for each resource must be respected to unit capacity and other operating limits like governor response capability.

- Concurrent modeling of non-coincidental zonal reserves is required. This modeling facilitates the economical sharing of energy and reserves offers across the zonal boundary.

Transmission Congestion Management

- Ensure energy and reserves dispatch results to satisfy limits imposed on inter-zonal MW transfers and inter-zonal grid security constraints.

- Effects of congestion are consistently reflected in the zonal energy and reserves clearing prices.

3.1.4 Energy and Reserves Dispatch Methods

The common methods to dispatch energy and reserves are: merit-order-based dispatch, sequential dispatch, and joint dispatch [57].

Merit-Order-Based Dispatch

In a multi-product electricity market, each product can have a separate merit-order stack. This stack is based on the price and quantity of bids from all market participants. Bid blocks might arrange in bid-price order to form the merit order in systems. Then the market process for energy and ancillary services (reserves) dispatched by traversing the energy stack, climbing up/down the stacked bid blocks until load demand is met [57].

When there is no coupling between energy and ancillary services markets, then each product may dispatch independently. This method is simple to implement, but when products are coupled together, maybe expected results are not feasible or optimal. This method is the simple approach for independently dispatching energy and reserves. However, to remove unit MW limit violations must be developed [58].

Sequential Dispatch

The sequential dispatch approach is a method that begins to address the issue of coupling among different competitive products. This method is the development version of the merit-order-based dispatch method. In this method, a priority sequence is defined for each product. For example, energy dispatch is the first priority to act, and another reserve is the second priority. In this method, available capacity of a resource is progressively reduced as higher priority products are dispatched from that resource. The degree of sophistication of recognizing the coupling varies from market to market [57].

Moreover, there may be no capacity limits of resources in the sequential dispatch approach, but correspondingly higher prices are produced in comparison to the merit-order-based dispatch approach [57]. The sequential dispatch needs further improvements to handle inter-dependencies among coupled products. Explicit evaluation of costs associated with lost opportunity, and impacts of production cost are mechanisms that may use to provide quantitative indices to analyze trade-off decisions. These mechanisms also can help to reduce the arbitrariness in the dispatch sequence [58].

Joint Dispatch

When multiple products are involved, the merit-order dispatch approach and its variants may not be extended easily to produce effective results, in particular, when network security constraints are an integral part of the optimization problem [57].

The joint dispatch method is based on formulating the problem in the context of constrained optimization as a Linear Programming (LP) problem. By the LP formulation, various constraints are taken into consideration like coupling capacity. This method provides coordinated dispatch between energy and ancillary services to achieve the most economical solution while the specified security constraints are observed in the optimization process [57].

The joint dispatch method can satisfy physical limits of units to achieve the best trade-off in the allocation of limited capacity between energy and ancillary services. In this method, energy and reserves clearing prices are Lagrange multipliers for binding constraints. These Lagrange multipliers can provide useful information which leads to correctly estimated small disturbances and changes in total cost. Ref [58] described the problem formulation of the joint dispatch method and also presents the numerical results of two case studies.

3.1.5 Different Types of Reserves from HVDC Systems

Many markets in Europe distinguishes between reserves under AGC that continuously regulates the system frequency (automatic reserves) and manual reserves that are dispatched manually by system operators [59]. Typically, automatic reserves are dispatched under a specific policy but manual reserves are dispatched with consideration of different criteria such as load flow studies and economic aspects.

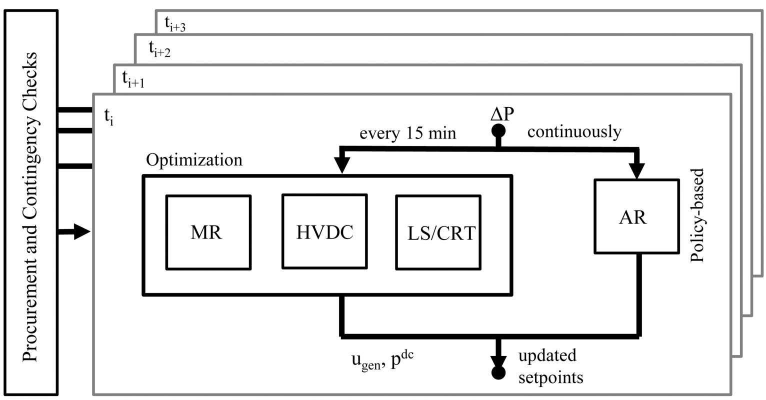

Figure 3.3: Overview of procurement and balancing operation with an HVDC link [59]

Figure 3.3 presents an overview of procurement and balancing operation with an HVDC link. In this procurement, t is the timestep, and ΔP is the active power deviations which are minimized. AR, MR, LC, and CRT are automatic reserves, manual reserves, load shedding and curtailment, respectively. The procurement ensures that sufficient flexibility is available for active power balancing in all considered timesteps and minimizing the active power deviations. The balancing operation uses the different flexibility options such as automatic optimizing and manual reserves together, changes in HVDC setpoints, load shedding, and curtailment [59]. Appropriate changes in power flow setpoints of HVDC lines may need to activate reserves.

The procurement problem can be formulated as an adjustable robust optimization problem with two stages. The first stage or procurement stage selects the optimal automatic and manual reserves' resources in a unit commitment that takes relevant contingencies into account. In the objective function of this problem, decision variables and linear costs must be selected from a set that ensures physical limits. These decision variables contain the bids for reserves which are offered by the balancing responsible sections.

The second stage (recourse stage) identifies the highest recourse deployment costs based on the procured capacities and scheduled generator setpoints. The objective function of this stage is evaluated for the worst case deviation contained in the uncertainty set. The worst case cost function also depends on the amounts procured in the first stage due to a trade-off between the cost of reserving capacity and the cost of activating reserves.

3.1.6 Exchange and Sharing Reserves Between Areas

To ensure operational security within a system there needs to be a geographical distribution of reserves and a sufficient amount of reserve capacity. Network Code on Load-Frequency Control and Reserves (NC LFCR) sets technical limits due to impacts of the geographical distribution and sharing reserves on the reserve capacity of systems. To maintain operational security, technical limits are necessary for the exchange and sharing reserves. Improving the economic efficiency in performing Load Frequency Control (LFC) is one of the main goals of the exchange and sharing reserves in multi-area grids [60].

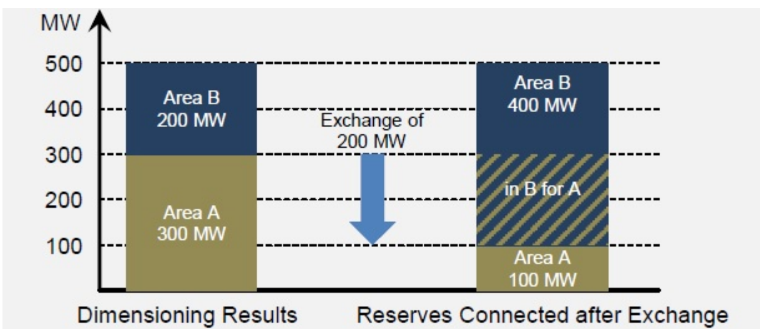

Figure 3.4: Example of the exchange 200 MW reserve capacity from Area B to Area A [60]

By exchanging reserves, TSOs can organize and ensure the availability of reserve capacity resulting from the dimensioning by relying on reserve providing units or reserve providing groups which are connected to an area operated by a different TSO. Figure 3.4 shows an example of the exchange 200 MW reserve capacity before and after exchanging from area B to area A. In this example, the dimensioning results are 300 MW for Area A and 200 MW for Area B. As mentioned above, without exchanging reserves between areas, reserve providing units or reserve providing groups that connected to each area must provide the reserve capacity. In this example, 300 MW must be connected in area A and 200 MW in area B.

As a result of exchanging reserves, 200 MW exchanged from area B to area A, which means that 200 MW of the reserve capacity required for area A is now located within area B. As can be seen, the geographical location of the reserve capacity is different from the dimensioning results for area A and area B, but the total amount of the reserve capacity for both areas is still 500 MW which is equal to the total amount without exchanging reserves.

Sharing reserves also allows TSOs to organize and to ensure the availability of the reserve capacity which is required by dimensioning rules by relying on the same reserves. Figure 3.5 shows an example of sharing 100 MW reserve capacity between TSOs of area A and TSOs of area B. The dimensioning rules' results are 300 MW for area A and 200 MW for area B. Without sharing reserves, the TSOs of area A and area B must ensure the availability of 300 MW and 200 MW reserve capacity, respectively.

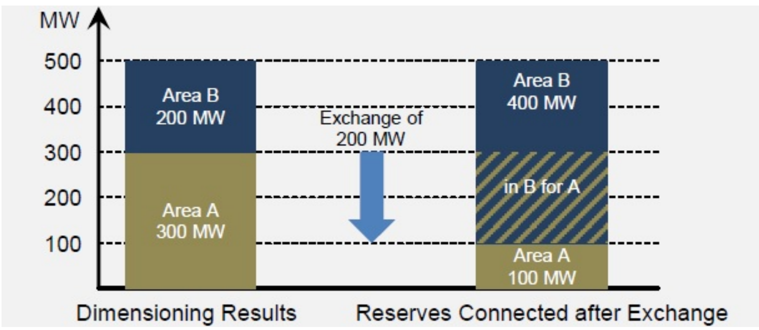

Figure 3.5: Example of sharing 100 MW reserve capacity between TSOs of Area A and TSOs of Area B [60]

It is unlikely that both area TSOs need to activate the full amount of their reserve capacity at the same time. Therefore, the TSOs of area A and area B can share a part of their reserve capacity. In this example, the TSOs of area B can use 100 MW of the reserve capacity of the TSOs in area A. Using the reserve capacity in multi-area grids can be based on an agreement between all areas. This agreement can be unilateral or bilateral. In the unilateral agreement, the TSOs of one area can use the reserve capacity of the TSOs in another area but not vice versa. In the bilateral agreement, the TSOs of areas can access to the reserve capacity of the TSOs in the other areas. Usually, the sharing agreement defines priority rights to the shared reserves under conditions where the TSOs of areas need reserves at the same time [60].

As a result of this example, the TSOs of area A and area B now need to ensure the availability of their reserve capacity are 300 MW and 100 MW, respectively. Furthermore, the TSOs of area A make 100 MW reserve capacity to the TSOs of area B. So, the total amount of the reserve capacity of the multi-area grid is 400 MW, whereas it was 500 MW without sharing reserves.

As observed, the exchange of reserves between areas only changes the geographical distribution of their reserve capacity. Sharing reserves changes the total amount of active power reserves in the synchronous areas with an impact on the geographical distribution. Also, the exchange of reserves can only perform if sufficient reserve capacity is available for involved TSOs to ensure the availability of their required reserve capacity resulting from the dimensioning requirements. In addition, sharing reserves allows for a reduction in the total reserves without performing a common dimensioning for these reserves. Therefore, limits for sharing reserves are essential to ensure operational security of systems [60].

Example of Power Exchange Between Synchronous Grids

The content of this part is mostly collected from [61]. The present practice with regard to the exchange of reserves between Norway/Sweden and Western Denmark, which is a part of the Nordic system and performed within the Nordel cooperation, is included in the description as the example of power exchange between these synchronous systems.

In the Nordic system, reserves are divided into Frequency Controlled Normal Operation Reserves (FCNOR) and Frequency Controlled Disturbance Reserves (FCDR). Based on Nordel regulations, the FCNOR must be at least 600 MW at 50 Hz for the synchronous system and completely activated within the frequency range 49.9-50.1 Hz. The reserve requirement is distributed among Norway, Sweden, Denmark, and Finland based on annual total consumption of the previous year. The distribution of FCDR is distributed according to the dimensioning fault within the respective subsystems, and at least 2/3 of the FCDR should be placed within the subsystems.

The joint list of regulation bids contains bids from both the synchronous system (Norway and Sweden) and Western Denmark system. During an hour operation, regulation is initially performed for network reasons and then, if it is necessary, trying to maintain the frequency in the synchronous system or the balance in the Western Denmark system.

Firstly, the synchronous system and Western Denmark exchange power in the form of supportive power. The supportive power can be defined as the power that adjacent TSOs can exchange as an element of the regulation of the balance in respective subsystems. Bids on the joint regulation list are usually used in the order of price (the exception of bids limited behind a bottleneck) to adjust the synchronous system frequency and the balance in Western Denmark. Activated bids are marked as balance regulations and included calculating the regulation price and regulation volume.

There are some principles to perform the exchange the supportive power for balance regulation between the synchronous system and Western Denmark. These principles are as following:

- Energinet.dk (Denmark TSO) sends plans in advance for each operating hour to exchange between the synchronous system and Western Denmark.
- The Energinet.dk plans are given per 15 minutes and they are drawn upon the basis of imbalance predictions in Western Denmark, current bids in the joint regulation list, and other information exchange between Statnett (Norway TSO) and Energinet.dk.
- Both Statnett and Energinet.dk are responsible for the plan concerning the coming hour with respect to regulation in both systems (at latest 15 minutes before the hour shift).

After the last principle, the plan can change during an hour operation according to rules. Some of the rules are:

- The supportive power is exchanged only in one direction during each hour between the synchronous system and Western Denmark. Also, the volume of supportive power can be increased or decreased during the hour operation but not more than every 15 minutes.
- After a reduction in the volume of supportive power, the volume cannot increase again during the same hour. However, this rule does not apply to hour shifts if the agreed exchange during the coming hour is higher than the current volume.
- Exchange of supportive power acts according to a power plan at 5 minutes discontinuation.

3.2 Challenges of LCC HVDC Systems

3.2.1 Background

Traditional LCC HVDC applications that based on mercury arc valves introduced in Kashira-Moscow (the USSR) in 1950 and then in Gotland (Sweden) in 1954. LCC technology has had a very important role in power transmission system around the world. The first application of LCC HVDC link based on thyristor valves was built in Eel River (Canada) in 1972. Using thyristor valves technology led to increasing the power capacity of HVDC links, reliability, and reduction in maintenance.

Thyristor technology has some advantages, however, extending this technology is limited due to its well-known limitations. One of the main limitations of this technology is a significant need for reactive power on both AC and DC sides. In an LCC HVDC link, the reactive power requirement begins when thyristors firing angles becomes positive after commutation voltage [62]. In reality, rectifiers at the sending end AC system point and inverters at the receiving end AC system point absorb and consume reactive power from grids like other loads [63]. Inverters under some conditions can produce reactive power and export to AC systems [64].

Consumption of reactive power in an LCC HVDC converter station depends on the firing angles of thyristors. This range is approximately 50 - 60% of active power transfer [63]. By using passive reactive power compensation equipment on the inverter side of LLC HVDC links, generated reactive power tends to reduce AC voltage drops under transients. Increasing the firing angle of thyristors causes higher reactive power consumption and as a result, leads to severe AC voltage drops. AC voltage drops are undesirable in power systems and need to be reduced by FACTS devices like SVC and STATCOM.

3.2.2 Control LCC HVDC Links and Integration in AC Grids

Controlling active power is one of the main advantages of all types of HVDC links. An LCC HVDC link is able to change its power factor by changing in the switching of AC harmonic filters, shunt capacitors, and shunt reactors. Hence, it can control AC voltage and reactive power in steps. Generally, connected AC grids accept this control especially if they are strong [65].

As mentioned before, LCCs consume reactive power in both their sides. The reactive power requirements are usually compensated at DC converter terminal substations. AC filters are also installed to reduce AC harmonics distortion at DC converter terminal substations. Capacitors in the AC filters can supply a part of the reactive power requirement at the fundamental frequency.

Other reactive power resources such as shunt capacitors, shunt reactors, SVCs, and synchronous condensers can provide the rest of the reactive power requirement at DC converter terminal substations. Using which type of these reactive power resources depends on the system design and configuration. Shunt reactors are the most compact device that commonly used to compensate reactive power in long high-voltage transmission systems. Three strategies are usually used to regulate reactive power devices by mentioned reactive power resources. These strategies are:

- Controlling regulated bus voltage (conventional AVR control).
- Switching according to the pre-defined switching table (Q control mode)
- Combination of the two previous strategies (V control mode)

In the conventional AVR control strategy, reactive power compensation devices regulate bus voltage when these devices are under AVR control. In the second strategy, SVCs and synchronous condensers are used to minimize reactive power consumption. In the third strategy, shunt capacitors and shunt reactors (switching devices) are switched according to the pre-defined switching table while SVCs and synchronous condensers are under AVR control and regulated within their reactive power limits to control bus voltage.

An LCC HVDC link can have smooth control of reactive power by adding SVCs at its AC terminals. Also, by inserting a Thyristor-Controlled Series Capacitor (TCSC) in series with converters, transformer impedance can control reactive power. Converter transformer tap changer also can remove the steady-state impacts at converters terminals.

Generally, integration AC sides of HVDC links into AC grids needs precise engineering services. For example, appropriately large AC harmonic filters must be designed in order to integrate an LCC HVDC terminal into connected AC grid. If the AC grid is weak, these filters can make a considerable increase in the system voltage during fault recovery and low order harmonic resonance problems. Dynamic reactive power control capability can help to improve the dynamic and transient performance of LCC HVDC links. This capability can be added to LCC HVDC links through new circuit topologies and control algorithms, or by adding new components such as series/shunt reactive power compensation devices [65].

In Ref [62], the three mentioned reactive power control strategies and a numerical case study are performed. Ref [63] also presented another strategy and its three aspects for controlling reactive power by controllable capacitor insertion and firing angle control. Ref [64] explained the simulation results of reactive power control in an LCC HVDC link with controllable capacitors.

3.2.3 Reactive Power and AC Voltage Control in LCC HVDC Links

Traditionally, to obtain extinction angle for a specific thyristor valve, a measure of the time between the completion of commutation and the point when the valve voltage becomes positive is taken. As explained above, in an LCC HVDC link, an inverter can produce reactive power when the extinction angle is negative and export some reactive power to its AC side. Therefore, a new method is required to measure negative values of extinction angles.

Ref [63] proposed a new method to measure extinction angles. In this method, systems can measure negative values of extinction angles. This method provides a design for a reactive power feedback controller. In this method, the extinction angle can be provided by an outer reactive power control loop instead of being a constant value. Figure 3.6 shows the proposed reactive power controller at the inverter side where Q_{ref}, Q_{meas}, and Q_{error} are the reactive power reference, measurement, and error, respectively. Also, γ_{order}, γ_{meas}, and γ_{error} are the extinction angle order, measurement, and error, respectively. CE is the inverter current error signal and α_{inv} is the inverter firing angle.

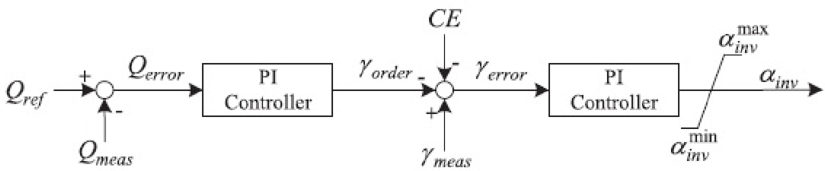

Figure 3.6: Inverter side reactive power controller [63]

In this controller, by minimizing the reactive power error through the first PI controller, the extinction angle order is generated. The PI controller is applied due to the non-linear relation between the extinction angle and reactive power. This controller has the ability to control the inverter terminal. Then, if required, it can export reactive power to its AC side. Figure 3.7 also presents the proposed inverter AC voltage controller where V_{ref} and V_{meas} are the inverter AC voltage reference and measured values, respectively, and α_{inv} is the inverter firing angle. In this controller, by minimizing AC voltage error, the PI controller has generated the inverter firing angle.

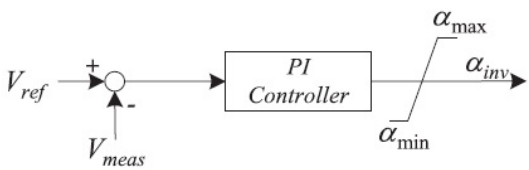

Figure 3.7: Inverter AC voltage controller [63]

3.2.4 Reactive Power/Voltage Control

Generally, LCC HVDC links need for reactive power and spinning reserves to cover reactive power/voltage support at connected AC grids. In a back-to-back LCC HVDC converter coupling, each station can control voltage of AC side and DC power transmission. AC voltage control acts via reactive power control. DC link between two AC systems (synchronous or asynchronous) also can allow postponement reserve generation and provides temporary energy exchange transactions in case of need. Commutation in line commutated converters is carried out by AC system voltage. Therefore, there will be some difficulties in continuing reliable commutation at very weak AC system voltages. This problem is one of the well-known disadvantages of LCC technology.

If Short Circuit Ratio (SCR) of an AC system at the point of connection to the rating of HVDC power transfer level is less than 2, the AC system is considered to be very weak. SCR of a system is the important index for controlling the voltage of AC busbar and reactive power exchange under steady-state conditions and dynamic performance during faults [66]. Systems with low SCR require a large number of small switchable reactive power equipment to adjust the reactive power requirement.

In LCC HVDC links, reactive power/voltage controllers are necessary even at zero DC power transfer. AC system response is also the important issue in reactive power exchange at HVDC converter stations and must be specified. By establishing load flow studies in a network that consists of AC and DC systems, one can determine the reactive power requirement, reactive power supply limits, network reactive power absorption limits, and reactive power surplus without significantly increasing system voltage. It should also be noted that under some conditions, AC systems are unable to accept any reactive power surplus from HVDC converter stations.

AC filters of an LCC link have direct impacts on the shunt reactors that are connected to converter buses. Moreover, AC filtering is a direct function of loading conditions, therefore, the reactive power absorption requirements are a function of loading. Performance of filtering is also defined in terms of individual harmonic distortion, total harmonic distortion, telephone influence factor, and IT product. So, covering the complete operating power range of an HVDC link is required to determine performance levels. Dynamic voltage change limits must be defined at each converter bus to minimize switching impacts of reactive power equipment. When a converter bus of an HVDC link is close to loads, limits are applied directly to the converter bus.

Unexpected and sudden changes in voltage of AC systems negative affect on the dynamic performance of the interconnected LCC HVDC link. These unexpected voltage changes cause commutation failures and DC control mode shifts. Both commutation failures and DC control mode shifts would cause transient power fluctuations across the tie and as a consequence lead to disturbances in both AC sides. Disturbances of commutation failure are due to the switching of reactive power compensation devices. These disturbances are usually severe disturbances and should be prevented.

3.2.5 Comparison of LCC and VSC HVDC Links in Active and Reactive Powers Control

Utilization of controllable power electronics devices has helped transmission systems to improve reliability and security. VSCs are one of these controllable devices. VSCs have the ability to rapidly control both active and reactive powers independently, and exchange reactive power with grids. VSC technology is also able to control AC voltage magnitude and phase that allows the utilization of separate active and reactive power control loops.

In a VSC HVDC link, the active power control loop can control active power or DC side voltage. In steady-state, active power flow on the AC side is equal to the active power transmitted from the DC side (disregarding the losses). Also, the reactive power control loop can control reactive power or AC side voltage of converters. Both of these modes can be selected at the sending end or receiving end sides of HVDC links.

On the other hand, in an LCC HVDC link, terminals can control reactive power by controlling the firing angle of thyristors, but require extra compensating equipment (extra cost). VSCs can provide the possibility to control both active and reactive independently without any need for extra compensating equipment. The reactive power control capability of VSC HVDC links also can contribute to an enhanced power quality by controlling AC voltages. In addition, VSC technology has a fast reactive power response and can maintain voltage level after disturbances.

It is expected that VSCs neutralize transient overvoltages in power systems in the shortest possible time by their fast reactive power response. Moreover, the system stability margin is enhanced with reactive power support capability. Thus, AC grids can operate at the higher voltage level (closer to the upper limit) and then the HVDC link can transfer more active power as a result. Unlike conventional LCCs, VSCs can be operated at a very low power and be controlled continuously both active and reactive power even at zero active power.

As mentioned, to improve the dynamic and transient performance of an LCC HVDC link, it can be equipped with the dynamic reactive power control capability. VSC technology already has the dynamic reactive power control capability. VSC HVDC links also can keep the voltage and frequency stable and provides voltage support, enhance transient stability, and improve the low-frequency power oscillations damping in connected power systems [67]. VSC technology could overcome most of the weaknesses of the LCC technology. Table 3.1 summarizes the main characteristics of both technologies.

Characteristic	LCC HVDC	VSC HVDC
Commutation process	Line-commutated	Self-commutated
Switch type	Semi controllable	Fully controllable
Semiconductor	Thyristor	IGBT
Change power direction by	Changing voltage polarity	Changing current direction
Power control	Only active power	Both active and reactive power
Reactive power demand	50%-60% power transfer	No reactive power demand
Reactive power compensation control	Discontinuous control	Continuous control
Size (footprint)	large	small
Black start capability	no	yes
Multiterminal configuration	Complex, limited to 3 terminals	Simple, no limitations

Table 3.1: Comparison of LCC and VSC technologies

In addition, SCRs of AC systems is no longer a limiting factor with VSC HVDC links. Thus, VSC HVDC links have the capability to connect to AC weak grids. As mention previously, disturbances in AC grids may lead to commutation failures in LCC HVDC links. VSCs based on self-commutating semiconductor devices, so, the risk of commutation failures is significantly decreased.

One of the limitations of VSCs is converter-current limitation through the current carrying capability of IGBT valves. This limitation appears as a circle in the PQ operation diagram. It should be noted, when converters in VSC HVDC links are planned to support their connected AC grids by supplying or consuming reactive power, the maximum active power must be limited to make sure the valve current is within the allowable range.

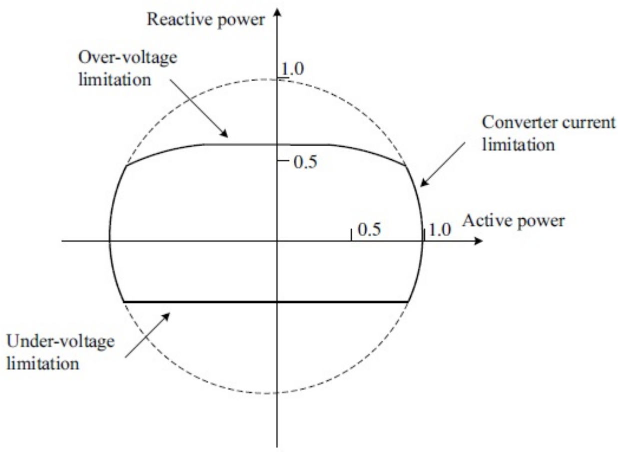

Figure 3.8: PQ diagram for a typical VSC-HVDC converter [68]

Modulation index limitation of VSCs is another limitation which determines the reactive power capability of VSCs. This problem is related to the over or under voltage magnitude of VSCs. The voltage level of VSCs can limit the over voltage limitation. The main circuit design and the active power transfer capability also can limit the under voltage limitation [68]. Figure 3.8 shows the PQ diagram for a typical VSC HVDC converter for both limitations. Ref [69] introduced a hierarchical control concept for integrating VSC HVDC links for voltage and reactive power control of connected AC grids.

Chapter 4

Simulations and Results

Theoretical background and required knowledge related to ancillary services from HVDC systems and sharing reserves between grids have been discussed in the previous chapters. This chapter is based on simulation studies of sharing active power reserves, examining the stability in disturbances, and DC droop control in a network based on the VSC MTDC system. The MATLAB/Simulink software was used for simulations. Simulations results are expected to validate the characteristics of multi-area grids and VSC technology that discussed in the previous chapters.

4.1 Test Model

4.1.1 Description

To build the test model, a Matlab/Simulink example (VSC-based HVDC transmission system) [71] is developed. Figure 4.1 depicts the test model in Matlab/Simulnik software. This test model shows the network that based on the VSC MTDC system. It consists VSC-based HVDC transmission links of 200 MVA (+/- 100kV) to transmit power between the four 230 kV, 2000 MVA, 50 Hz AC systems (AC system 1, AC system 2, AC system 3, and AC system 4 subsystems). The AC systems are modeled by damped L-R equivalents with an angle of 80 degrees at the third harmonic. The rectifiers (VSC 1 and VSC 3) and the inverters (VSC 2 and VSC 4) are three-level Neutral Point Clamped (NPC) voltage source converters that using close IGBT/diodes with single-phase triangular carriers with 1350 Hz based Sinusoidal Pulse Width Modulation (SPWM) switching.

Each converter station has two degrees of freedom. The AC side of the converters stations includes: the step-down transformer (Wye grounded/Delta), the AC filters, and the converter reactor. The DC side of the converters stations includes: the capacitors, the DC filters, and the smoothing reactors.

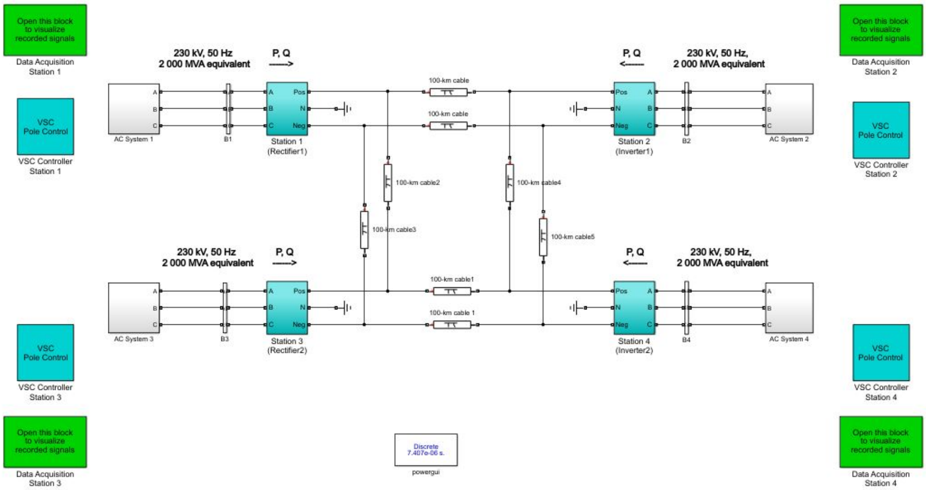

Figure 4.1: Test model in MATLAB/Simulink software

AC Side:

- The step-down transformers of the converters are used to allow the optimal voltage transformation. The present winding arrangement blocks triple harmonics produced by the converters. The transformers tap changer or saturation are not simulated. The tap position is rather at a fixed position determined by a multiplication factor applied to the primary nominal voltage of the converters transformers. The transformers ratios for the rectifiers' side are 0.915 and for the inverters' side are 1.015 and the multiplication factors are chosen to have a modulation index around 0.85.

- The AC filters are an essential part of power transmission systems to meet AC systems harmonic specifications. The 40 Mvar shunt AC filters are 27th and 54th high-pass tuned around the two dominating harmonics. The AC filters can connect shunt elements on the AC systems sides or the converters sides of the transformers. Since these filters are only high-frequency harmonics, therefore shunt filtering is relatively small compared to the converters rating.

- The converters reactors (with the transformers leakage reactance) allow the VSCs output voltages to shift in phase and amplitude with respect to the AC systems Point of Common Coupling (PCC) (bus B1 for station 1, bus B2 for station 2, bus B3 for station 3, and bus B4 for station 4) and also allow control of converters active and reactive power outputs. The converters reactors (an air-cored device) separate the fundamental frequency (filter bus) from the raw PWM waveform (converters buses). In this model, the converters reactors value is 0.15 p.u. and the transformers leakage reactance value is 0.15 p.u.

DC Side:

- The 70 μF reservoir DC capacitors are connected to the VSCs terminals. These capacitors have an influence on the system dynamics and the voltage ripple on the DC side of the converters.

- The DC side filters blocking high-frequency are tuned to the 3rd harmonic (the main harmonic present in the positive and negative pole voltages). Reactive converters currents generate a relatively large third harmonic in both the positive and negative pole voltages but not in the total DC voltages.

- The smoothing reactors are connected in series at each pole terminal to improve system performance and reduce harmonic currents, transient overcurrents, and current ripples on the DC side of the converters.

Other Devices:

- Cables (2 pi sections) are used to connect VSC 1 to VSC 2, VSC 3 to VSC 4, VSC 1 to VSC 3, and VSC 2 to VSC 4.

- DC voltage balance control blocks (U_{DC_0}) are used to keep the DC side balanced and can keep the level of the difference between the pole voltages zero.

- Three-phase programmable voltage sources. The AC system 1 and the AC system 3 are equipped with three-phase programmable voltage source blocks to apply three-phase voltage sags.

- Discrete control system generates the three sinusoidal modulating signals that are the reference value of the bridge phase voltages. The amplitudes and phases of the modulating signals can be calculated to control the flow of active and reactive powers at the PCCs, or the flow of reactive power at the PCCs and the pole to pole DC voltage.

- Clark transformations blocks transform the three-phase quantities to space vector components α and β, which are the real and imaginary parts, respectively.

- Signal measurements (U and I) on the primary sides are rotated by $\pm\pi/6$ according to the transformers connections to have the same reference frames as the signal measured on the secondary sides of the transformers.

- dq transformations blocks calculate the direct axis d and the quadratic axis q quantities from the α and β quantities.

- Phase Locked Loop (PLL) blocks measure the system frequency and provide the phase synchronous angles (θ) for the dq transformation blocks. In steady-state, sin(θ) is in phase with the fundamental of the α component and phase A of the PCCs voltages (Uabc).

Simulations are performed for normal operation and two case studies. In normal operation, all of the converter stations and the AC systems work with their nominal ratios. In the first case study, the VSC 1 is lost at t=1.5 s. In the second case study, a minor and a severe disturbances are applied together at the converter station 1 bus at different times.

4.2 Simulations Results

Before starting to review the simulations results, some fundamental parameters must be specified. Table 4.1 shows these parameters and their description in the test model.

Fundamental Parameters	
Parameter Name	Description
U_{dc}	DC voltage on the DC side of converters
P_{dc}	Power on the DC side of converters
U	AC voltage at point of common coupling
P	Active power at point of common coupling
Q	Reactive power at point of common coupling
U_{abc}	AC three-phase voltage
I_{abc}	AC three-phase current
U_f	AC voltage on the AC filters bus
I_v	Converters reactors phase current
$_{ref}$	Suffix denotes reference values
$_{AB}$	Suffix denotes alpha beta components
$_{PN}$	Suffix denotes positive and negative poles on DC side of converters

Table 4.1: Description of the fundamental parameters in the test model

Table 4.2 represents the operation mode of the VSCs and their controllers. Also, Table 4.3 represents user-defined references points of the VSCs.

VSC	Operation Mode	Controllers
VSC 1	Rectifier	Active power controller (P), Reactive power controller (Q)
VSC 2	Inverter	DC Voltage Droop Controller ($U_{dcdroop}$), Reactive Power Controller (Q)
VSC3	Rectifier	Active power controller (P), Reactive power controller (Q)
VSC 4	Inverter	DC Voltage Droop Controller ($U_{dcdroop}$), Reactive Power Controller (Q)

Table 4.2: Operation mode of the VSCs and their controllers

4.2.1 Normal Operation

Surely, in order to compare the results of the case studies, it is necessary to demonstrate the simulation results in normal operation. To illustrate the simulation results, graphs of the main parameters of each VSC are shown. These parameters are: DC voltage on the DC side of converters, power on the DC side of converters, AC response voltage at the PCCs, active power at the PCCs, and reactive power at the PCCs as these values are very

VSC	Reference points
VSC 1	P_{ref}= 0.5 pu, Q_{ref}=0.1 pu
VSC 2	P_{ref}= -0.5 pu, Q_{ref}= -0.1 pu, U_{dref}= 1 pu
VSC3	P_{ref}= 0.5 pu, Q_{ref}=0.1 pu
VSC 4	P_{ref}= -0.5 pu, Q_{ref}= -0.1 pu, U_{dref}= 1 pu

Table 4.3: User-defined references points of the VSCs

important for understanding the response and dynamic performance of the VSC MTDC system. The simulation results in normal operation are shown in Figure 4.2 - Figure 4.6. All of the simulation results for each converter (DC side, PCC, control signals, filter bus, and voltage balance control blocks) individually are presented in the appendix (Figure A.7 - Figure A.26) of this thesis.

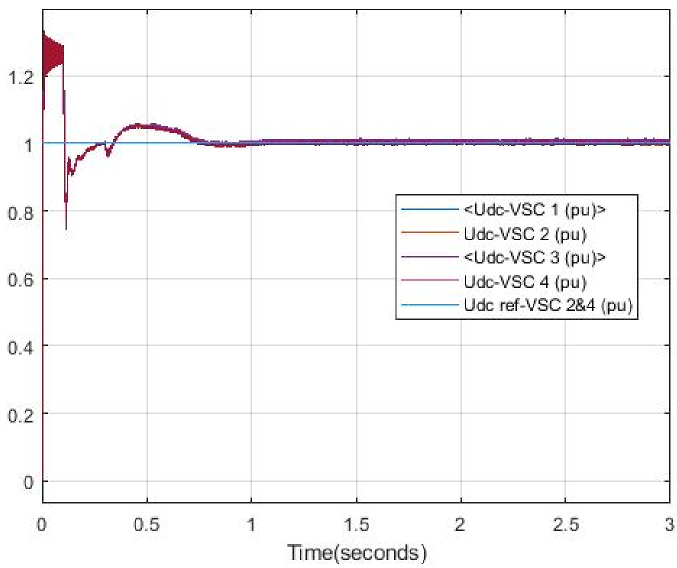

Figure 4.2: DC voltage on the DC side of converters, normal operation

Simulation in normal operation is performed to examine the responses and behaviors of the AC systems and the VSCs. The sample time of the controllers model (Ts_Control) is 74.06 μs (0.001/1350 s), which is 10 times greater than the simulation sample time. The laters are chosen to be one-hundredth of the PWM carrier period (7.406 μs) that gave an acceptable simulation precision. The power equipment, the anti-aliasing filters, and the PWM generator blocks use the fundamental sample time (Ts_Power) of 7.406 μs.

The systems are programmed to start and reach steady-state. After steady-state has

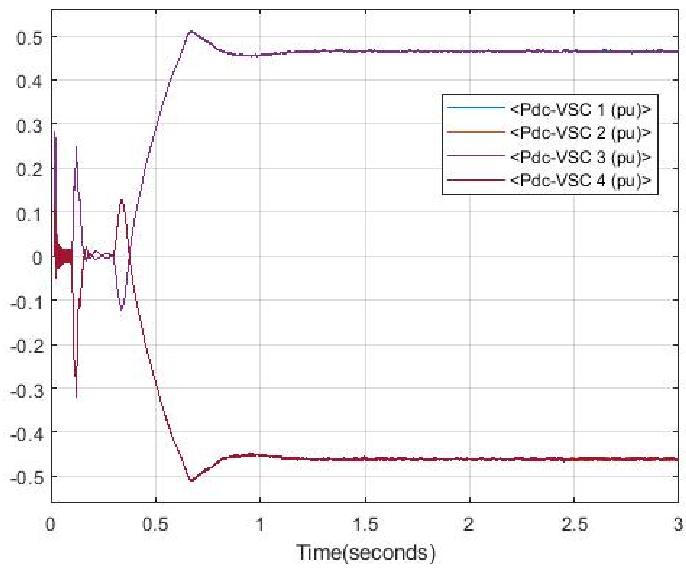

Figure 4.3: Power on the DC side of converters, normal operation

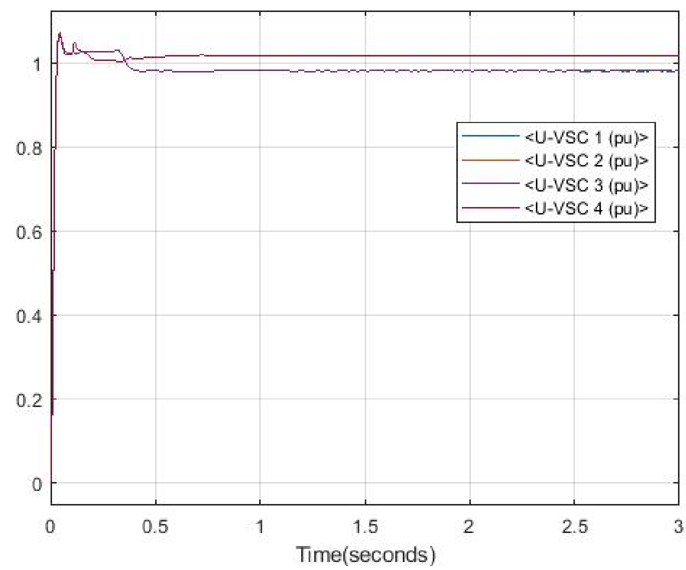

Figure 4.4: AC response voltage at the PCCs, normal operation

been reached, the constant values, as defined in Table 4.3, are applied to the references

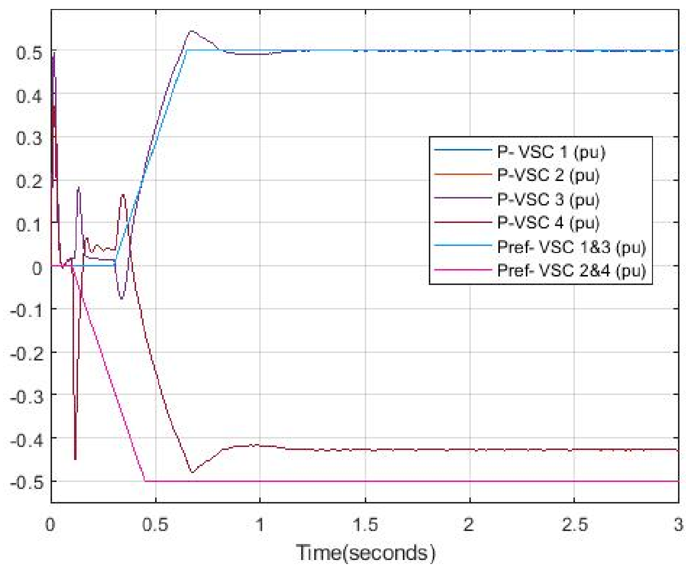

Figure 4.5: Active power at the PCCs, normal operation

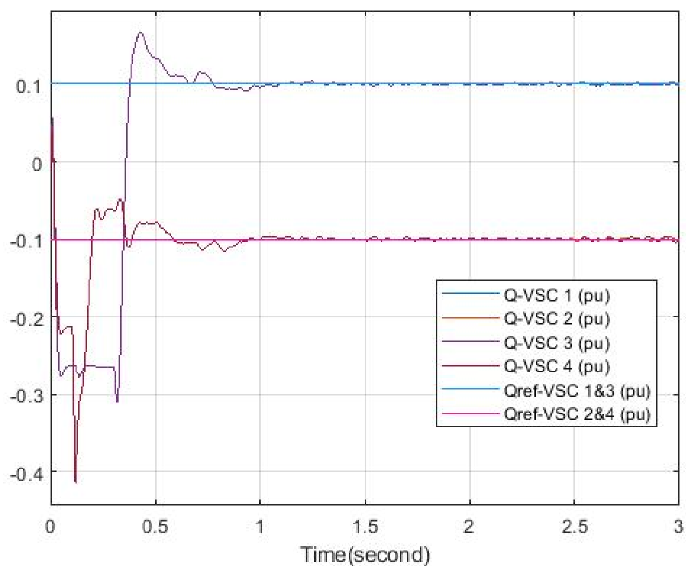

Figure 4.6: Reactive power at the PCCs, normal operation

points of active and reactive powers to the rectifiers (VSC 1 and VSC 3), and the references points of DC voltage and reactive power to the inverters (VSC 2 and VSC 4). The dynamic responses of the regulators can be observed in the graphs. It is worth mentioning that 1 p.u. of the references and measured values of active power, reactive power, and DC voltage are equal to 200 MW, 200 Mvar, and 200 kV, respectively.

The active power loops, reactive power loops, and voltage loops contain the outer loop regulators that compute the reference values of the converters current vectors ($I_{ref}dq$), which are the inputs to the inner current loops. The control modes for the active power flow at the PCCs or the pole to pole DC voltages are in the d axis. Also, the control mode for the reactive power flow at the PCCs is in the q axis.

In the active power control regulator blocks, the extra ramping blocks ramp the power orders to the desired values with adjusted rates when the control blocks are deblocked. The ramped values must be reset to zero when the converters are blocked (the first case study).

The reactive power control regulator blocks combine PI controls with feed-forward controls to increase the speed responses. To avoid integrator wind-up the error must reset to zero when the measured voltages at the PCCs are less than a constant value. This function is very useful for the systems during AC disturbances (the second case study). Each AC voltage control override block based on two PI regulators will override the reactive power regulators to maintain the PCCs' AC voltages within an allowable range, especially in steady-state.

Each DC voltage control overrides block is also based on two PI regulators. The DC voltage control overrides blocks can override the active power regulators to maintain the DC voltages within a secure range. These blocks can control the DC voltages during a disturbance in the AC systems of the converter stations. When the active power control blocks are disabled, the DC voltage control regulator blocks are enabled. The DC voltage control regulator blocks outputs are reference values for the d components of the converters current vectors and for the current reference limitation blocks.

The current reference calculation blocks transform the active and reactive powers references (calculated by the P and Q controllers) to the current references according to the measured voltages at the filter buses. The current references are estimated by dividing the power references by the minimum preset voltage values. The current reference limitation blocks also limit the current reference vectors to maximum acceptable values.

The reference voltage conditioning blocks take into account the actual DC voltages and the theoretical maximum peak values of the fundamental bridge phase voltages in relation to the DC voltages to generate the newly optimized reference voltage vectors.

In the test model, the ratio between the maximum fundamental peak phase voltages and the DC voltages is 0.816 ($\sqrt{2}/\sqrt{3}$) for a modulation index of 1. The nominal modulation index (0.816) can be reached by choosing the nominal lines voltages of 100 kV at the transformers secondary buses and the nominal DC voltages of 200 kV. Theoretically, the converters should be able to generate up to 1.225 p.u. ($\frac{1}{0.816}$) when the modulation index is equal to 1 which can be observed in the graphs.

The dynamic performance of the systems is verified by following the user-defined references points, such as active power, reactive power, and DC voltage. Station 2 and station 4 converters are first deblocked approximately at t=0.25 s to control DC voltage (Figure A.15d and Figure A.25d). Then, station 1 and station 3 converters are deblocked approximately at t=0.35 s to control active power (Figure A.10d and Figure A.20d). Then, active powers in these converters are ramped up slowly to 0.5 p.u.

It can be seen from the simulation results that the VSCs are followed up their references points and the behavior of the VSC 1 and VSC 3 are exactly the same, as well as the VSC 2 and VSC 4 in opposite direction. Steady-state is reached approximately at t=0.8 s with DC voltage at 1.0 p.u. (Figure 4.2) in the all converters. It can be noted, in steady-state, by disregarding the losses, the active power on the AC side of the VSCs is almost equal to the power transmitted from the DC side of them. Also, as can be seen, all converters control the reactive power flow to 20 Mvar (0.1 p.u.) in the converter station 1 and converter station 3 and to -0.1 p.u. in the converter station 2 and converter station 4 (Figure 4.6).

4.2.2 Case Study 1

After simulating the normal operation of the test model, in the first case study, the VSC 1 is lost at t=1.5 s. The purposes of this simulation are: to demonstrate the dynamic performance of the VSCs and interactions between AC and DC grids, and to represent the sharing active power between systems when needed in multi-terminal networks with the MTDC system.

In this simulation, at t=1.5 s a zero pulse will send to IGBTs in the VSC 1 to turn off them through their gates. Simulation results are presented for DC voltage on the DC side of converters, power on the DC side of converters, AC response voltage at the PCCs, active power at the PCCs, and reactive power at the PCCs in Figure 4.7 - Figure 4.11. In addition, all of the simulation results for each converter individually are presented in the appendix (Figure A.27 - Figure A.46).

The sample time of the controllers and the fundamental sample time are the same as the normal operation. The constant values, as defined in Table 4.3, are applied to the references points of active and reactive power to the rectifiers, and the references points of DC voltage and reactive power to the inverters. It can be seen, before losing the VSC 1, all controllers are followed up their references points.

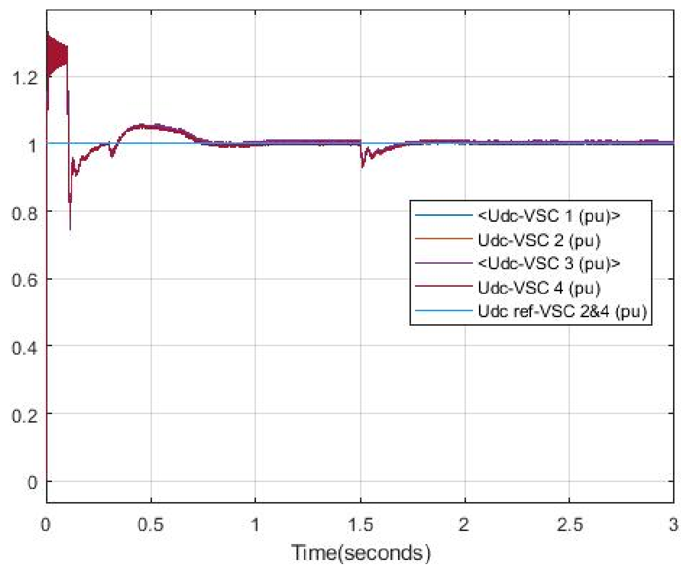

Figure 4.7: DC voltage on the DC side of converters, case study 1

At t=1.5 s the VSC 1 is lost and both power in the DC side and active power at the PCC of the converter station 1 immediately go to zero (Figure 4.8 and Figure 4.10). Since VSC 1 and VSC 3 were operating as rectifiers, after losing the VSC 1, only one rectifier

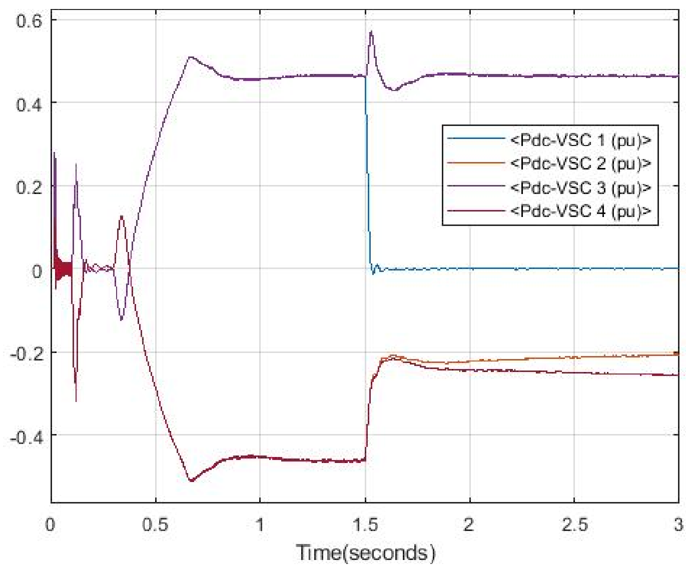

Figure 4.8: Power on the DC side of converters, case study 1

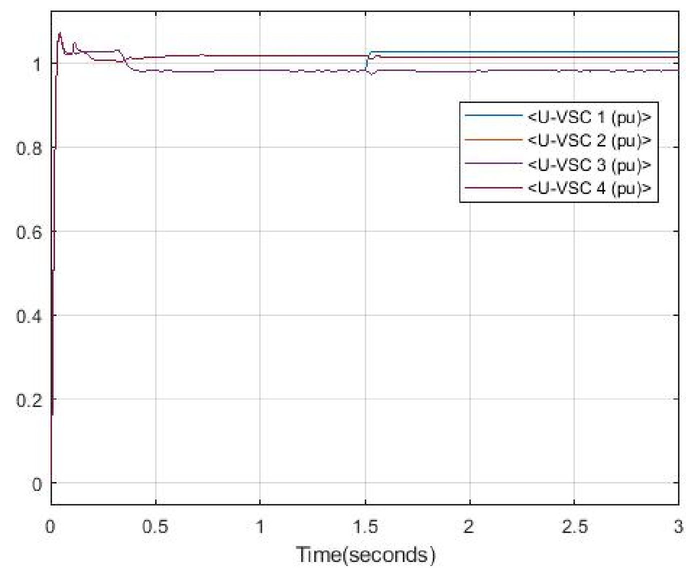

Figure 4.9: AC response voltage at the PCCs, case study 1

remains in the network to supply both VSC 2 and VSC 4, which are working as inverters

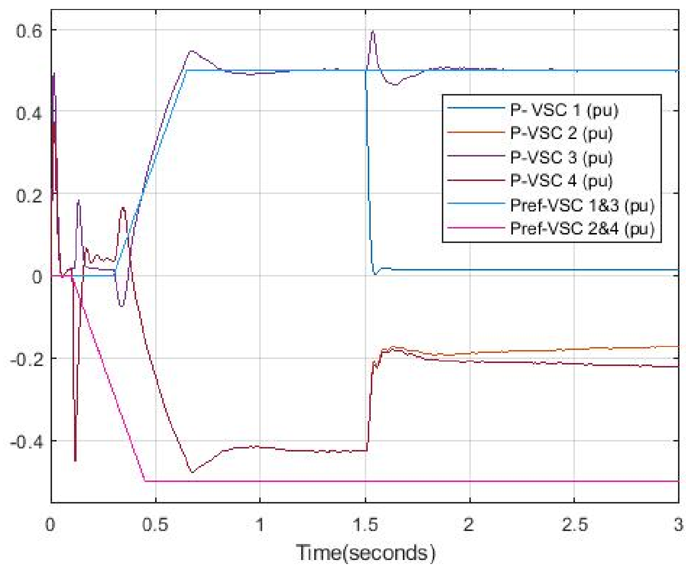

Figure 4.10: Active power at the PCCs, case study 1

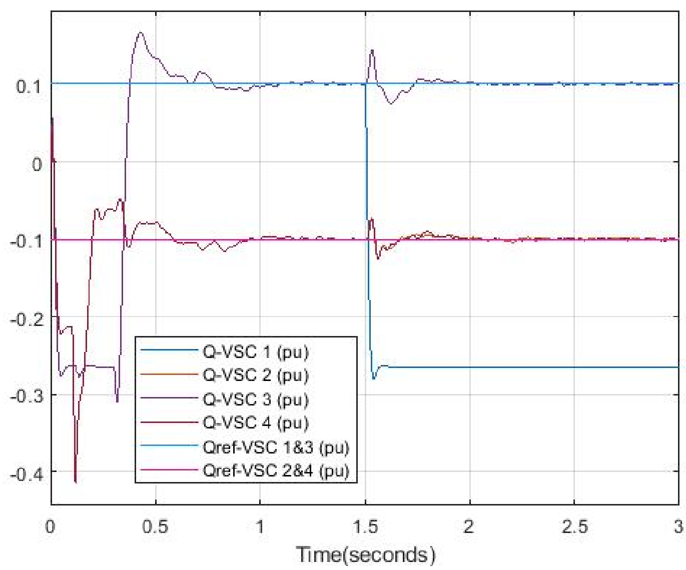

Figure 4.11: Reactive power at the PCCs, case study 1

and supplying to the connected AC systems. Since DC voltage droop control is employed

(Figure 4.7), VSC 2 and VSC 4 did not follow up their references points and share almost equal active power (Figure 4.10). One can be concluded from the simulation results that the other VSCs jointly alleviate power deficit caused by the VSC 1 outage.

As noted above, the control mode for the active power flow at the PCCs is in the d axis and the control mode for the reactive power flow at the PCCs is in the q axis. It can be verified from Figure A.29a and Figure A.29b. When VSC 1 is lost, active power at the PCC of the VSC 1 goes to zero but reactive power goes from 0.1 p.u. to -0.25 p.u. This action is due to the passive equipment in the AC system 1 and the parallel diodes with IGBTs on the VSC 1. Other converter stations are controlled the reactive power flow and followed up their references points with small deviations around t=1.5 s.

After losing the VSC 1, the discharge of the DC side capacitors leads to a reduction in the DC voltages for all of the VSCs in the MTDC system. This reduction in the DC voltages is detected by the DC voltage controlling converters. These converters recharged the capacitors and restored the DC voltages to the desired values (Figure 4.7). On the other hand, AC response voltage at the PCC of the VSC 1 is increased from 0.98 p.u. to 1.02 p.u. and consequently, the modulation index of the VSC 1 is changed from 0.816 to 1 at t=1.75 s (Figure A.29c). It also can be observed that the behavior of the DC voltage balance control blocks in all of the VSCs are the same.

The dynamic performance of the transmission system is verified by the dynamic responses from the other VSCs to the VSC 1 outage. By sharing equal active power from VSC 2 and VSC 4 after the outage of the VSC 1, the other converters continue to work and tried to re-balance the entire system. This action is one of the main advantages of the VSC HVDC technology and the multi-terminal topology.

4.2.3 Case Study 2

In this case study, a minor and a severe disturbances are applied at converter station 1 to demonstrate the dynamic performance of the VSCs and the system recovery in the AC side disturbances. It is expected the system recovery from the disturbances will be quick and stable.

In this simulation, at t=1.5 s a three-phase voltage sag (the minor disturbance) is first applied at converter station 1 by the three-phase programmable voltage source inside the AC system 1. The voltage source is programmed for a step of -0.1 p.u on the voltage magnitude at t = 1.5 s, for a duration of 10 cycles (0.2 s).

Then, after the system recovery for the minor disturbance, a three-phase to ground fault (the sever disturbance) is applied at the station 1 bus. A 10 cycles three-phase to ground fault is applied at t = 3 s at the PCC of converter station 1 (bus B1). Figure 4.12 shows the test model in this case study.

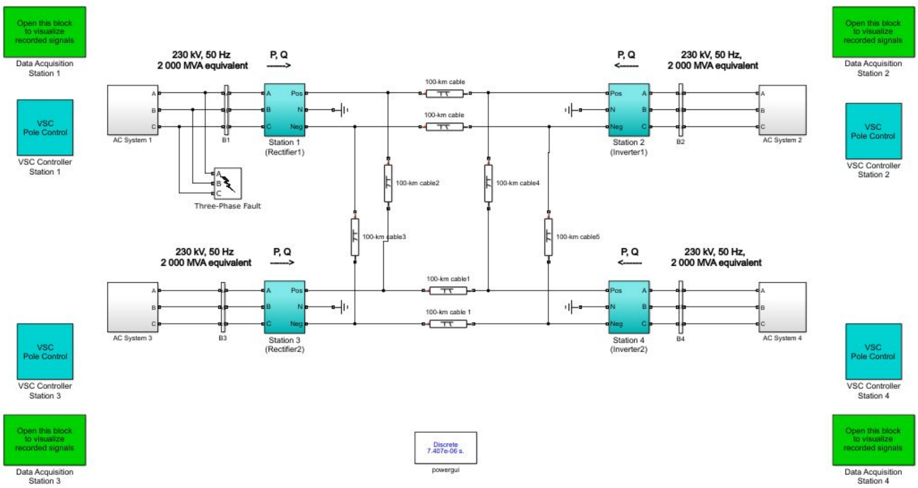

Figure 4.12: Test model in the second case study

Simulation results are presented for DC voltage on the DC side of converters, power on the DC side of converters, AC response voltage at the PCCs, active power at the PCCs, and reactive power at the PCCs in Figure 4.13 - Figure 4.17. In addition, all of the simulation results for each converter individually are presented in the appendix (Figure A.47 - Figure A.66).

It can be observed, after the AC voltage sag, the active and reactive powers of the VSCs have small deviations from the pre-disturbance values. The VSC 2, the VSC 3, and VSC 4 did not change their working points during the minor disturbance. The system recovery time in the all VSCs is around 0.3 s for the minor disturbance and steady-state is reached again approximately at t=1.8 s.

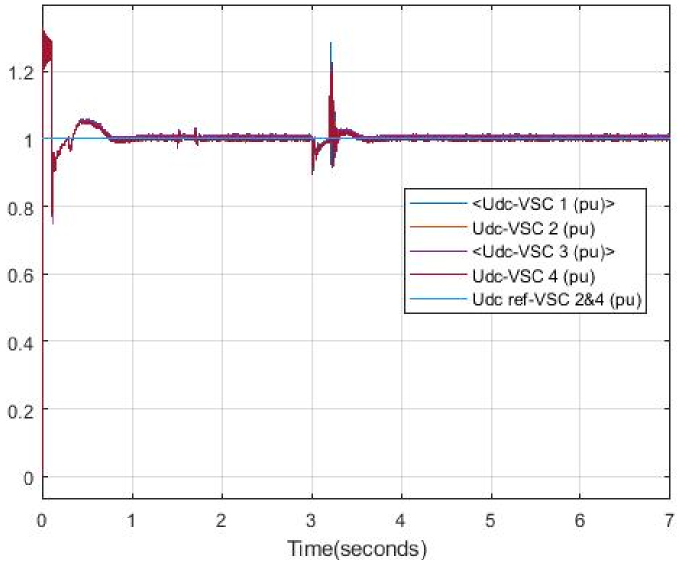

Figure 4.13: DC voltage on the DC side of converters, case study 2

Then, at t=3 s the three-phase to ground fault is applied at the converter station 1 bus for 10 cycles. During the severe three-phase fault at converter station 1, the transmitted DC powers are almost halted and the DC voltages of the VSCs tend to increase (Figure 4.13) since the DC side capacitors of the VSCs are being excessively charged. Table 4.4 presents the overshoot values in the DC voltage of the VSCs exactly after clearing the three-phase fault.

VSC	DC voltage on the DC side
VSC 1	1.28 pu
VSC 2	1.18 pu
VSC3	1.2 pu
VSC 4	1.23 pu

Table 4.4: Overshoot values in the DC voltage of the VSCs exactly after clearing the three-phase fault

DC voltage control override in the active power controller (in station 1 and station 3) attempts to limit the DC voltage within a fixed range. After clearing the disturbances, the VSC 1 immediately changes its PQ working point to support the AC system 1.

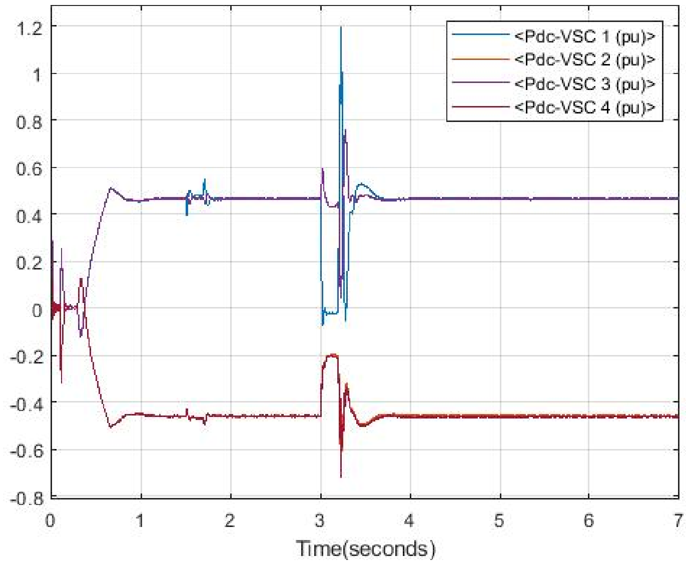

Figure 4.14: Power on the DC side of converters, case study 2

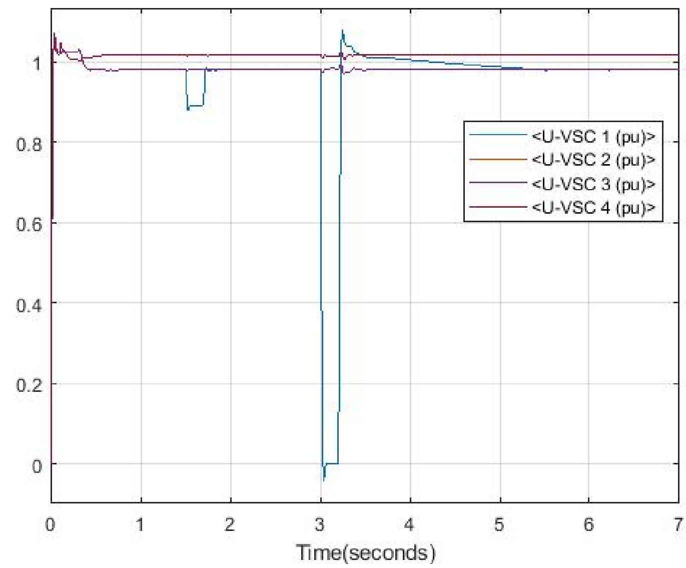

Figure 4.15: AC response voltage at the PCCs, case study 2

It can be seen from simulation results that the d and q components of the VSC 1 cur-

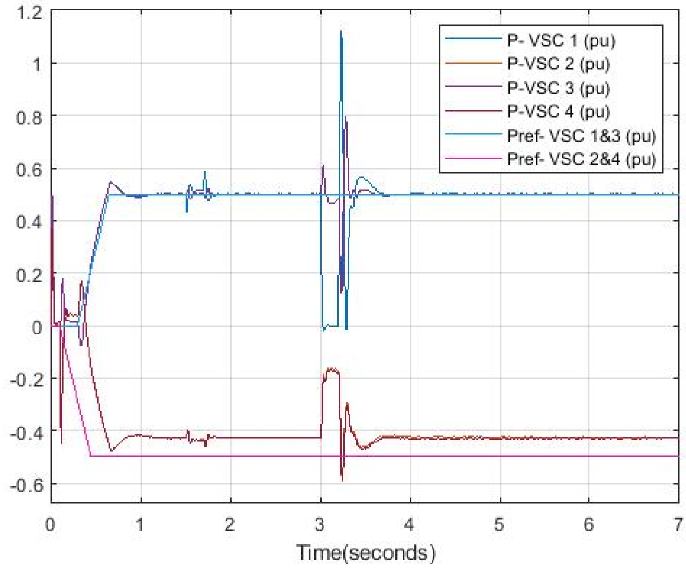

Figure 4.16: Active power at the PCCs, case study 2

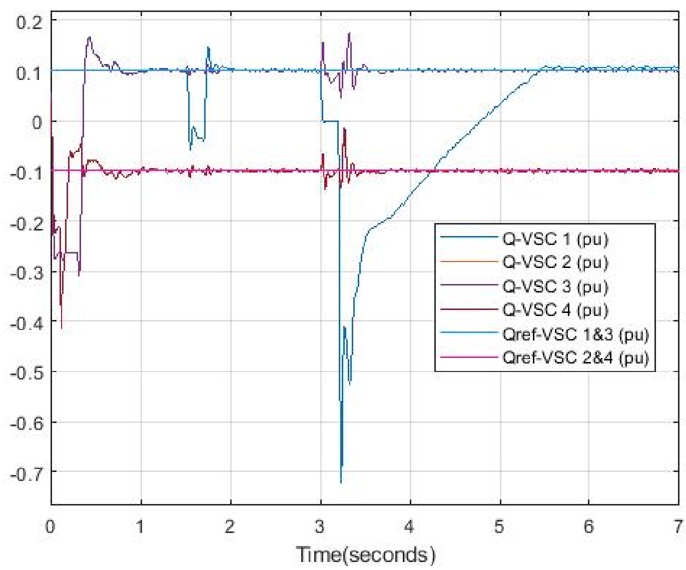

Figure 4.17: Reactive power at the PCCs, case study 2

rents are oscillating more than the d and q components of the other converters currents

(Figure A.49a and Figure A.49b). Moreover, the d component of the other converters currents is oscillating more than the q component. As explained above the relation between the active power loops and the d components, one can observe overshoots in the active powers of the VSC 1 and VSC 3 (Figure A.48b and Figure A.58b).

The systems are recovered well after the three-phase fault around t= 3.6 s, except for the reactive power of the VSC 1 (Figure 4.17). To improve the performance of the reactive power controller of the VSC 1, this controller can be tuned to control its bandwidth and transient responses. Finally, the reactive power of the VSC 1 is followed up its reference point at t= 5.5 s (Figure A.48c).

It also can be observed that during the three-phase fault, the VSC 2 and VSC 4 acted similarly to the first case study and sharing almost equal active power for 0.2 s to support the entire system (Figure A.53b and Figure A.63b). One can be concluded that the VSC MTDC system can decouple the system with the severe disturbance as long as the active power control of the DC system is not compromised.

The dynamic performance of the VSCs and the fast and stable systems recovery in the AC side disturbances are verified from the simulation results of this case study. Other VSCs continue to work during faults and their small deviations due to the responses to the new power flow condition as a consequence of the minor and the severe disturbances in the converters station bus 1.

Chapter 5

Conclusions and Future Works

This chapter presents the discussion and conclusions related to the works done in this thesis. The limitations of this thesis are also explained in this chapter. In addition, the future works related to this thesis are brought up for further researchers in this field.

5.1 Discussion and Conclusions

In this thesis, the interconnection of AC and DC grids by using modern HVDC links has been investigated. Theoretical study of ancillary services from HVDC systems for AC grids and exchange these services between grids has been conducted based on available literature. In addition, a test model based on the VSC MTDC power transmission system has been designed in MATLAB/Simulink by developing a Matlab example. Simulations in normal operation and two case studies have been performed, and the simulations results have been analyzed to demonstrate interactions between the four AC grids and the VSC MTDC system and the dynamic performance of the VSCs under different conditions (normal operation and disturbances).

Simulations were performed to demonstrate sharing active power between different grids when needed and their dynamic performance under different conditions. It was observed in the MTDC system, by losing a VSC, the other VSCs jointly alleviate power deficit caused by the VSC outage. The reactive power injection can be controlled without significant impacts on the other converters. However, the active power injection depends on the power flows through the VSC MTDC system, and can be controlled by the DC voltages. It was also concluded that each local controller can affect the stability and the DC voltage in other converter stations even small deviations from minor disturbances. So, the droop constant selection must be addressed in the multi-variable system in both of the normal operation and disturbances to consider the dynamic performance of the entire system. Droop control was employed to regulate DC voltage in the simulations and provided the active power sharing when needed among different VSCs without communications which could improve the reliability and efficiency of the entire system.

It has been concluded from the simulations results that the VSC MTDC system has the capability to decouple the system with the severe disturbance as long as the active power control of the DC system is not compromised. This point was noteworthy by disregarding the losses that in steady-state, the active power on the AC side of VSCs was almost equal to the power transmitted from the DC side of them.

Based on the literature review and theoretical backgrounds, one can conclude that MTDC systems, in particular, VSC MTDC systems are a suitable and optimal solution for the large-scale integration of renewable energy sources into the existing AC grids and the expansion of international energy markets through super grids. This conclusion was verified by the simulation results.

Both theoretically and through simulations, it has been demonstrated that the VSC technology can improve the system stability, reliability, and security of the connected AC systems, by the fast responses and the fast systems recovery when needed, and controlling both active and reactive power independently.

Finally, it can be concluded that using MTDC grids can reduce control reserve activation and communications for sharing reserves during disturbances between AC systems. This reduction has considerable influence on the dynamic performance of systems as well as future power system planning.

5.2 Limitations

In this thesis, ancillary services from HVDC systems were investigated as much as possible. Deep dive and implementation of each ancillary service in Matlab/Simulink on the test model was needed to define a large amount of grids codes, principles, strategies, and methods.

The simulation studies were supposed to be based on the IEEE 13 node test feeder, the voltage level of this model is 4.16 kV. It has not been reasonable to use HVDC transmission systems for this level of voltage. However, a test model based on the IEEE test model with FACTS devices carried out during the thesis work. Hence, after consulting with my supervisor, we were decided to make a new test model based on the VSC MTDC power transmission system to demonstrate interactions between AC and DC grids and sharing active power between multi-area grids.

5.3 Future Works

As MTDC power transmission systems are still in the development process, there are several factors that require further attention. With a basis in this thesis, some of the possible future works are presented as follows:

- The test model can be developed to analyze behaviors of various grids by combining different types of grids such as stiff grids, weak grids, passive grids, renewable energy sources.

- System protection of MTDC transmission systems and interactions between AC and DC equipment during disturbances can be investigated by extending the test model.
- Load shedding system can prevent the failure of the entire system during emergency conditions. This system can be investigated in the test model by defining a priority list for loads.
- The test model will be more realistic by introducing a joint market between different areas (systems) based on the price of ancillary services and formulating prices in different times and conditions.

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Appendix A

Appendix A

In this appendix, before presenting the simulations results, internal views of the AC systems, the converter stations, and the VSCs controllers in the test model are shown. Then, all simulation results at DC side, PCCs, control signals, filter buses (Bfilter and Bconv), and voltage balance control blocks individually for each converter in normal operation and the two case studies are represented.

Internal Views of the Test Model

AC Systems

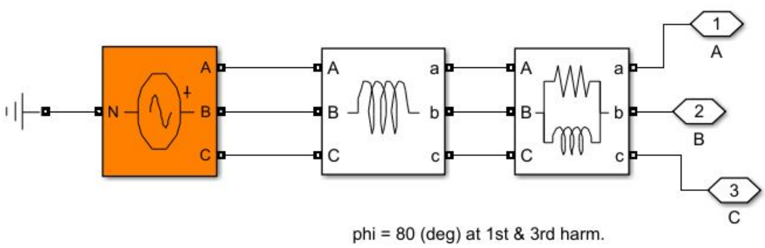


Figure A.1: Internal view of the AC system 1&3

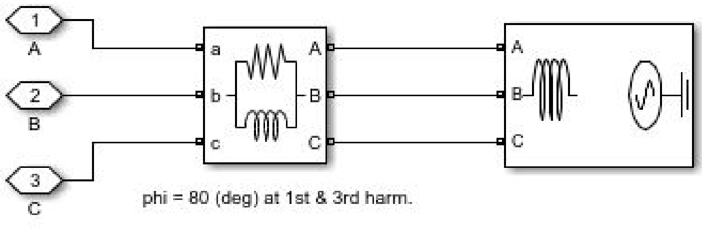


Figure A.2: Internal view of the AC system 2&4

Converter Stations

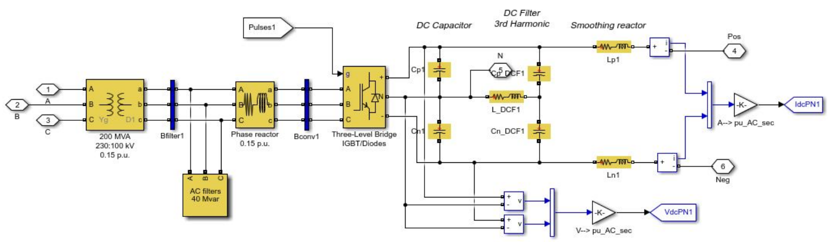


Figure A.3: Internal view of the converter stations

VSCc Control Stations

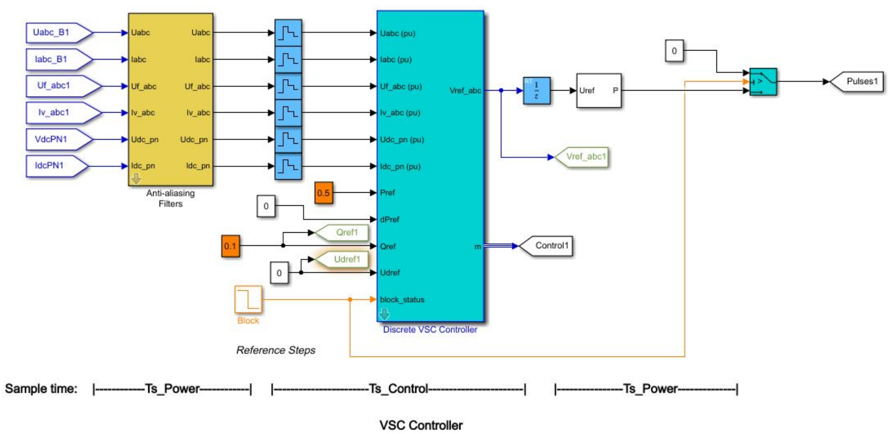


Figure A.4: Internal view of the VSC Control station 1&3, normal operation and case study 2

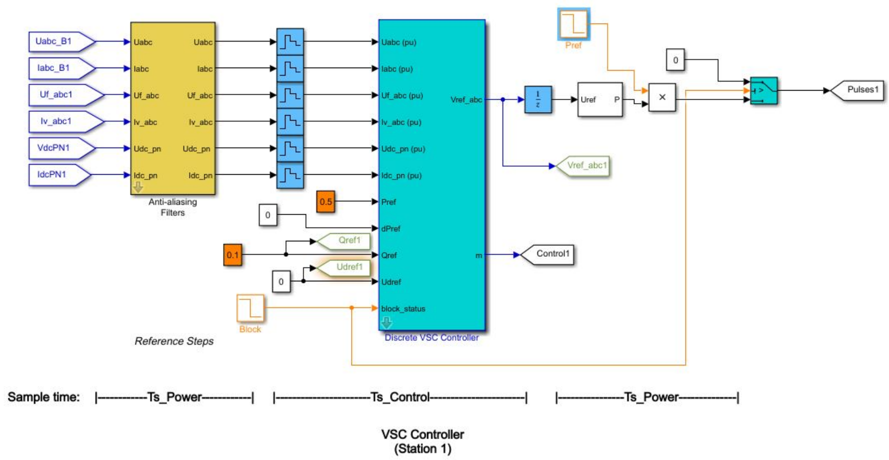


Figure A.5: Internal view of the VSC Control station 1, case study 1

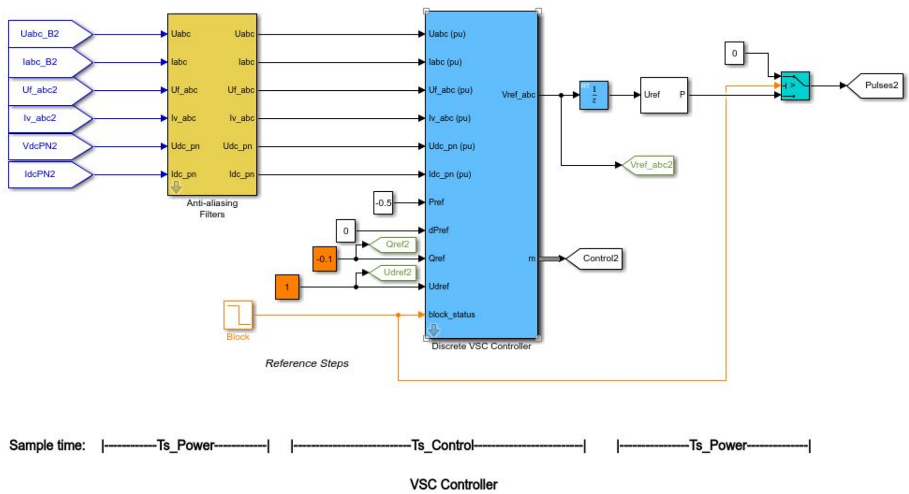
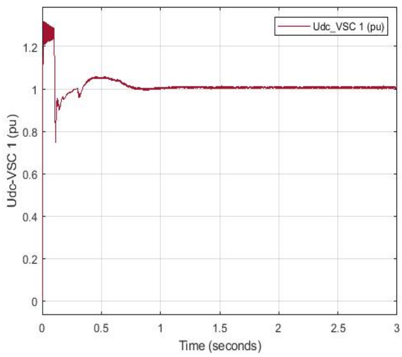


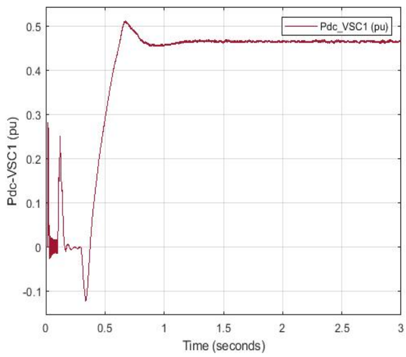
Figure A.6: Internal view of the VSC Control station 2&4

Simulations Results

Normal Operation

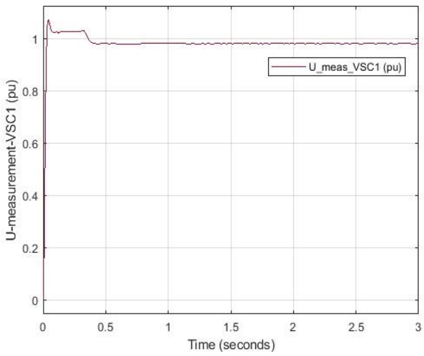


(a) DC voltage on the DC side of VSC 1

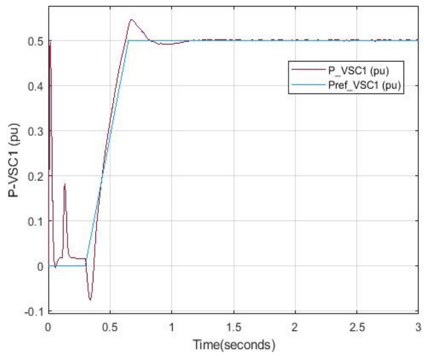


(b) Power on the DC side of VSC 1

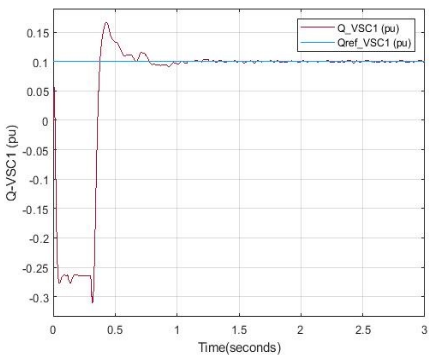
Figure A.7: DC side of VSC 1, normal operation



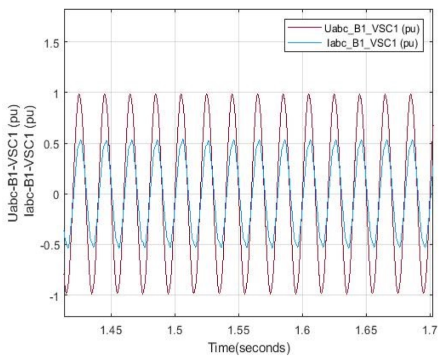
(a) AC response voltage at the PCC of VSC 1



(b) Active power at the PCC of VSC 1

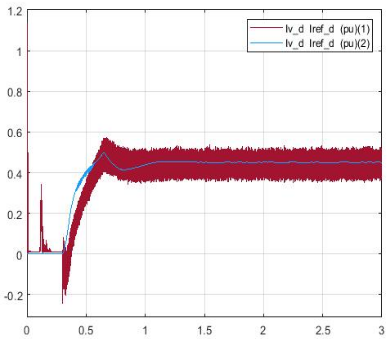


(c) Reactive power at the PCC of VSC 1

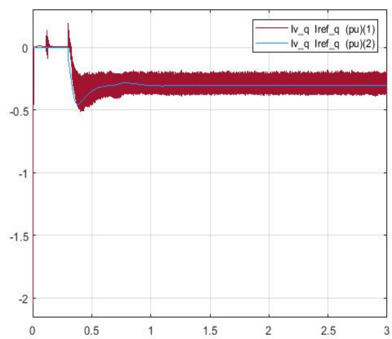


(d) Three-phase voltage and current at the PCC

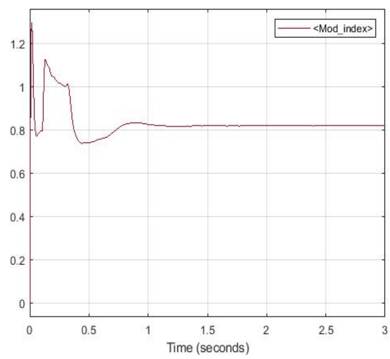
Figure A.8: PCC of VSC 1, normal operation



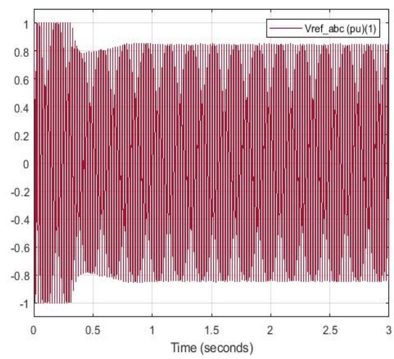
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

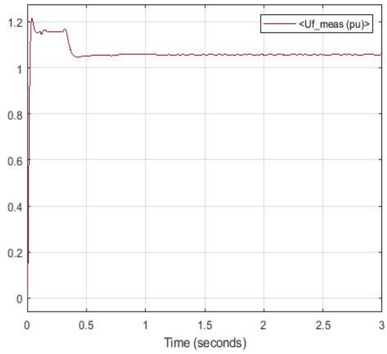


(c) Modulation index

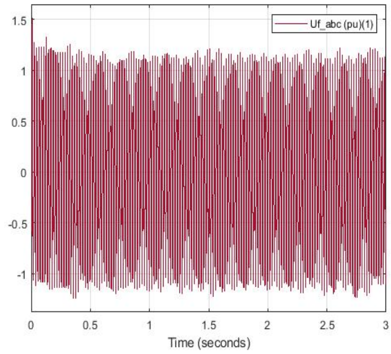


(d) Three-phase reference voltage

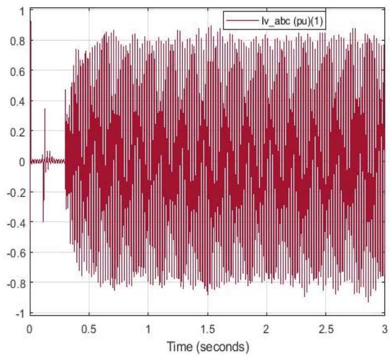
Figure A.9: Control signals of VSC 1, normal operation



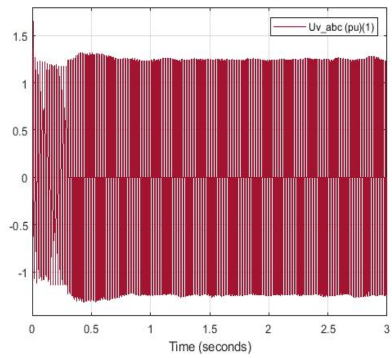
(a) Voltage on the AC filter bus of VSC 1



(b) AC voltage on the AC filter bus of VSC 1



(c) Converter reactor phase current of VSC 1



(d) Converter reactor phase voltage of VSC 1

Figure A.10: Filter bus of VSC 1, normal operation

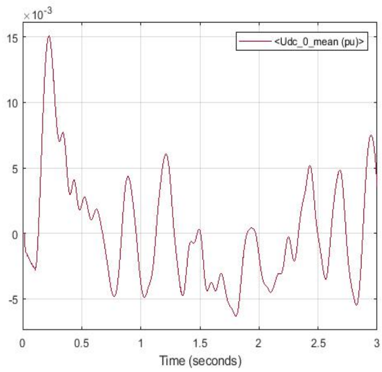
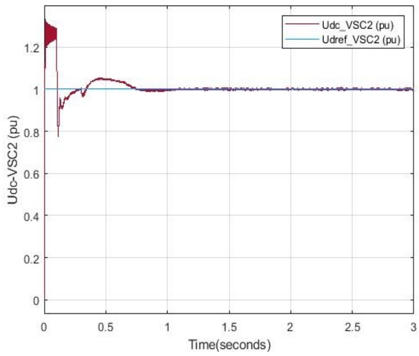
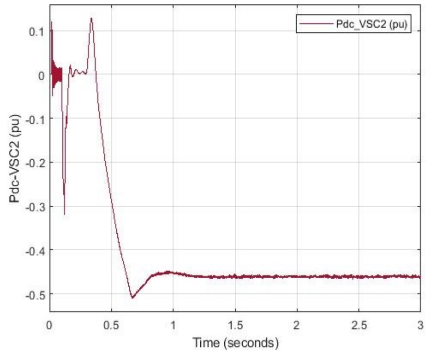


Figure A.11: Sum of the positive and negative pole voltages on the DC side of VSC 1, normal operation

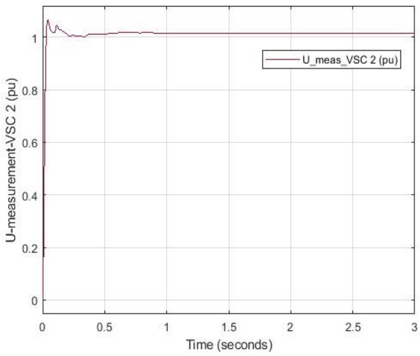


(a) DC voltage on the DC side of VSC 2

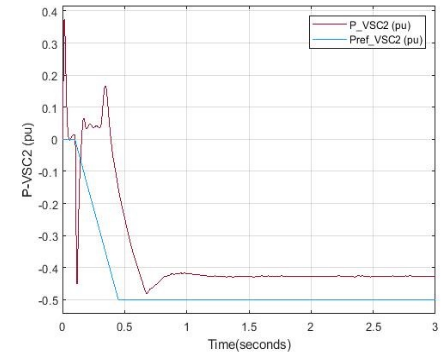


(b) Power on the DC side of VSC 2

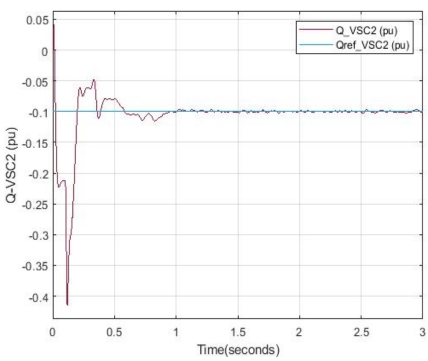
Figure A.12: DC side of VSC 2, normal operation



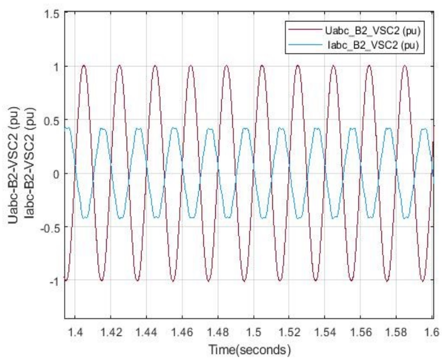
(a) AC response voltage at the PCC of VSC 2



(b) Active power at the PCC of VSC 2

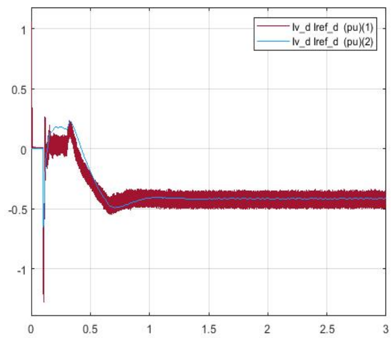


(c) Reactive power at the PCC of VSC 2

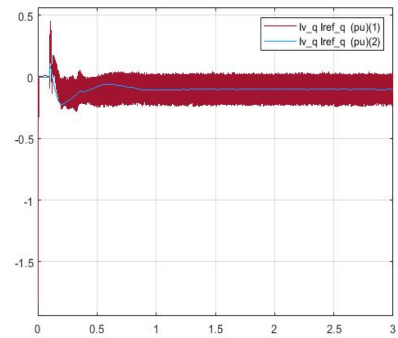


(d) Three-phase voltage and current at the PCC

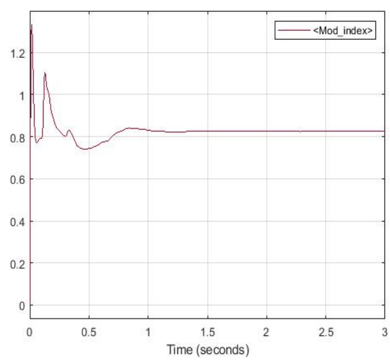
Figure A.13: PCC of VSC 2, normal operation



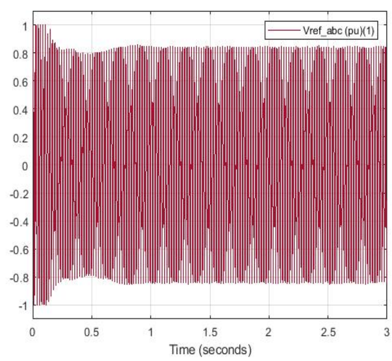
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

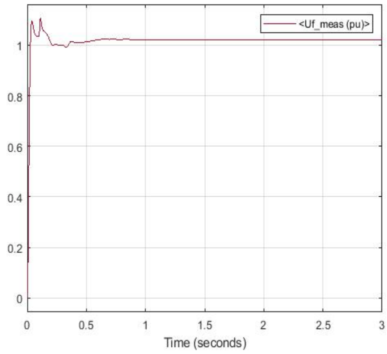


(c) Modulation index

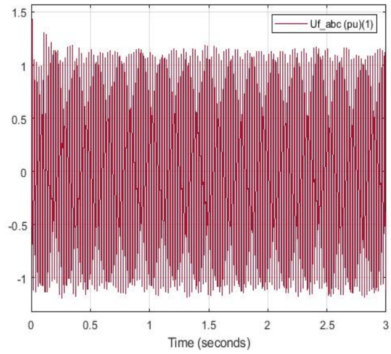


(d) Three-phase reference voltage

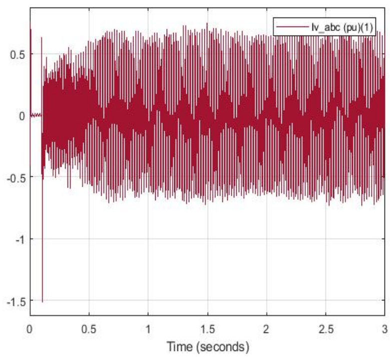
Figure A.14: Control signals of VSC 2, normal operation



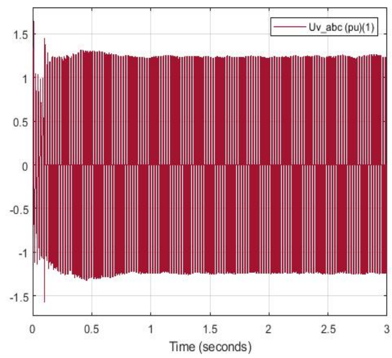
(a) Voltage on the AC filter bus of VSC 2



(b) AC voltage on the AC filter bus of VSC 2



(c) Converter reactor phase current of VSC 2



(d) Converter reactor phase voltage of VSC 2

Figure A.15: Filter bus of VSC 2, normal operation

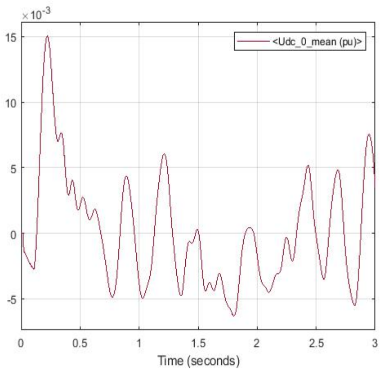
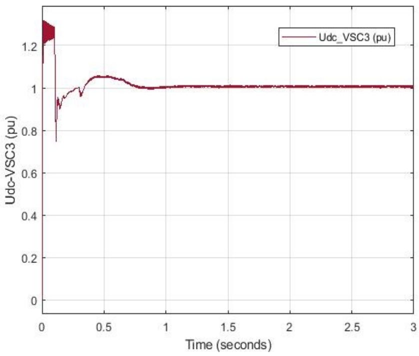
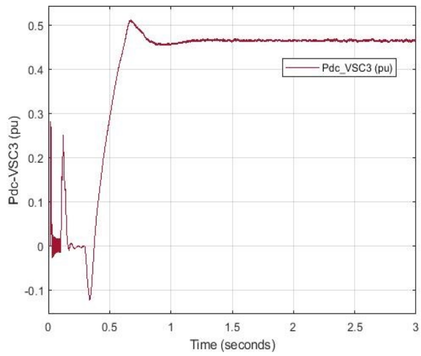


Figure A.16: Sum of the positive and negative pole voltages on the DC side of VSC 2, normal operation

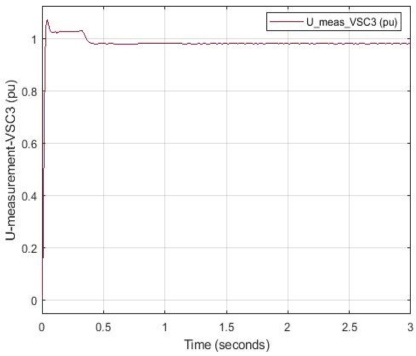


(a) DC voltage on the DC side of VSC 3

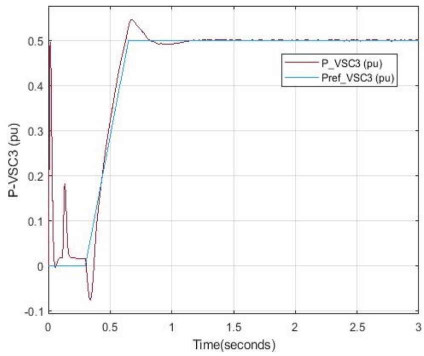


(b) Power on the DC side of VSC 3

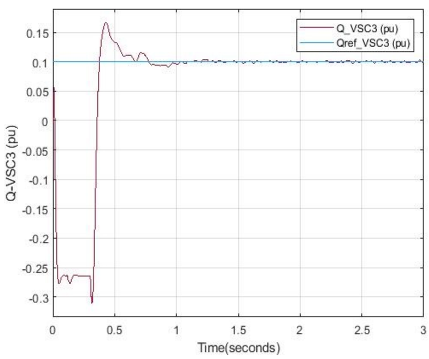
Figure A.17: DC side of VSC 3, normal operation



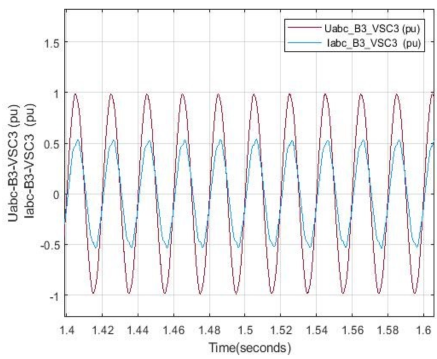
(a) AC response voltage at the PCC of VSC 3



(b) Active power at the PCC of VSC 3

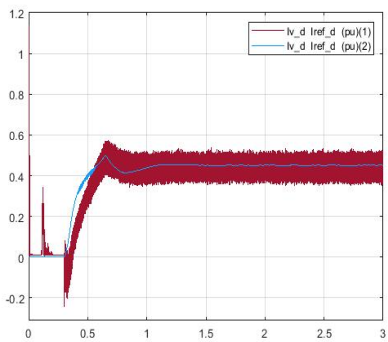


(c) Reactive power at the PCC of VSC 3

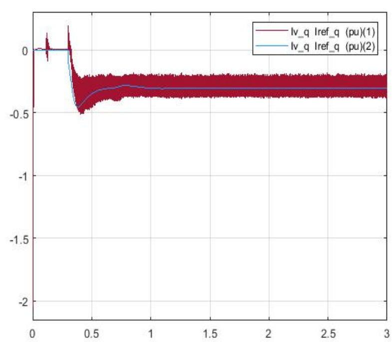


(d) Three-phase voltage and current at the PCC

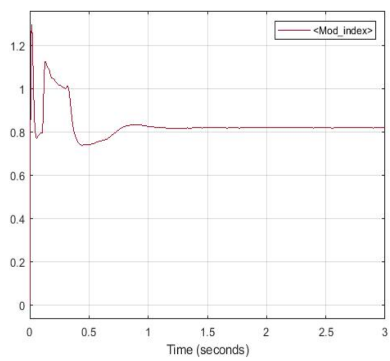
Figure A.18: PCC of VSC 3, normal operation



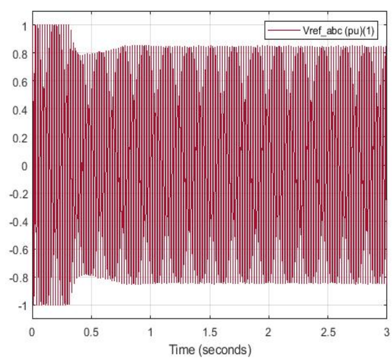
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

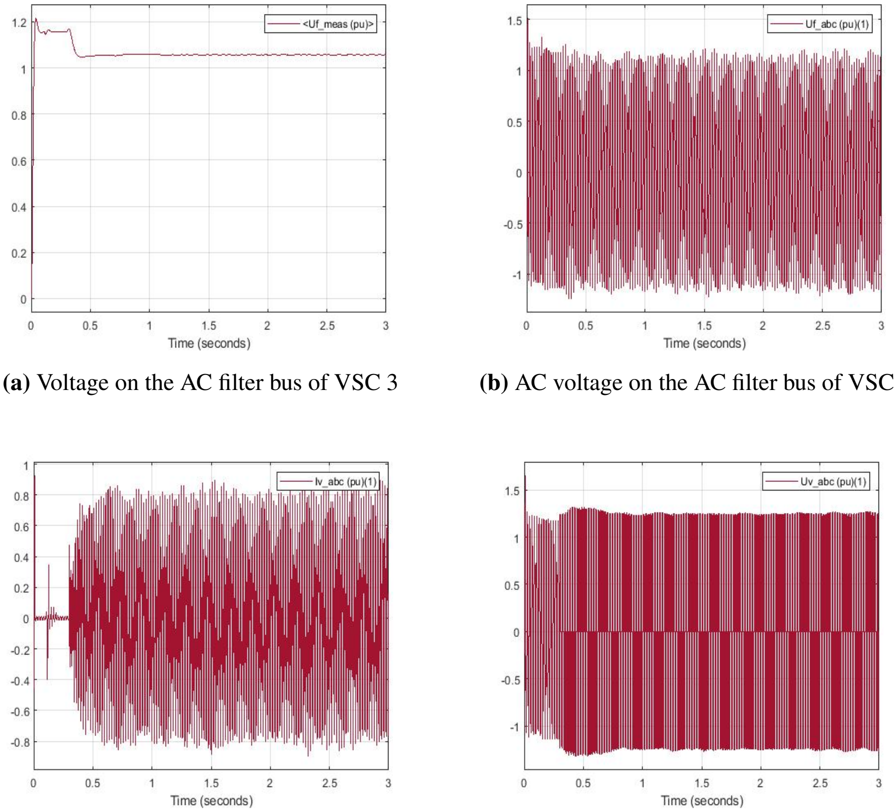


(c) Modulation index



(d) Three-phase reference voltage

Figure A.19: Control signals of VSC 3, normal operation



(a) Voltage on the AC filter bus of VSC 3

(b) AC voltage on the AC filter bus of VSC 3

(c) Converter reactor phase current of VSC 3

(d) Converter reactor phase voltage of VSC 3

Figure A.20: Filter bus of VSC 3, normal operation

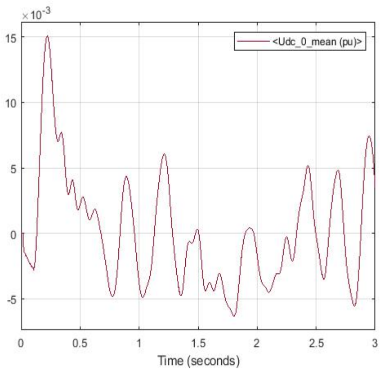
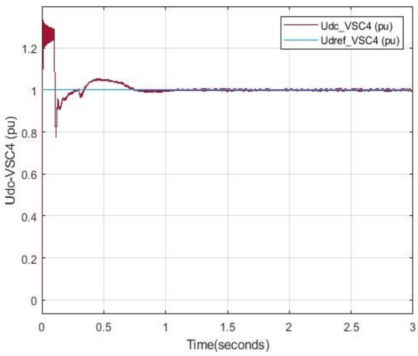
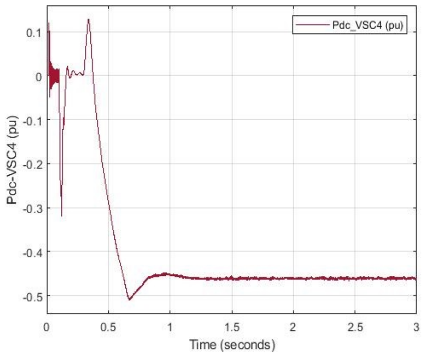


Figure A.21: Sum of the positive and negative pole voltages on the DC side of VSC 3, normal operation

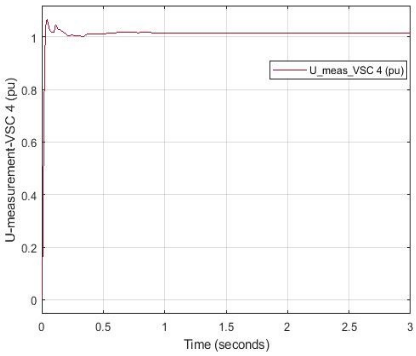


(a) DC voltage on the DC side of VSC 4

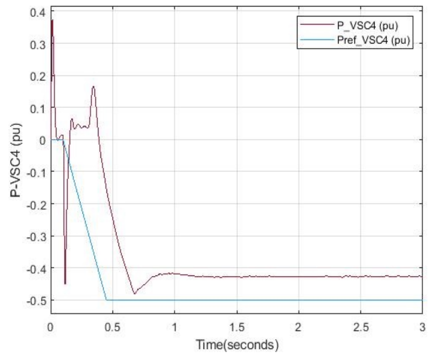


(b) Power on the DC side of VSC 4

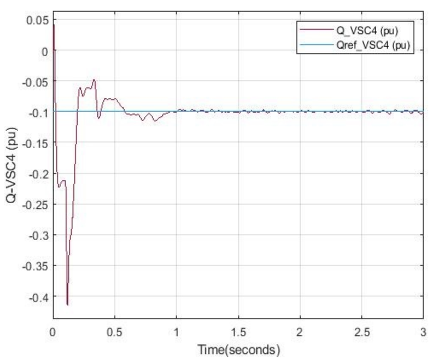
Figure A.22: DC side of VSC 4, normal operation



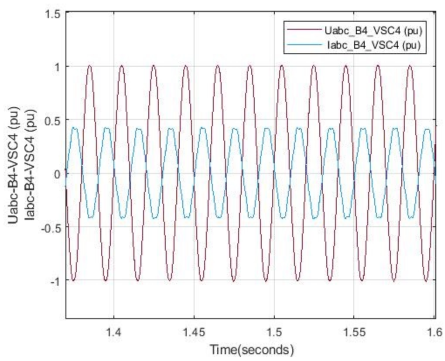
(a) AC response voltage at the PCC of VSC 4



(b) Active power at the PCC of VSC 4

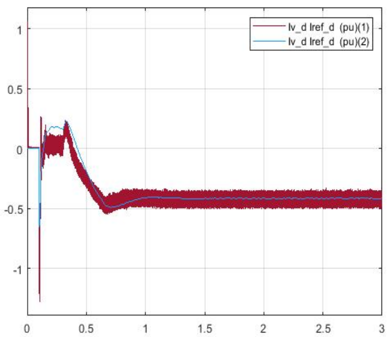


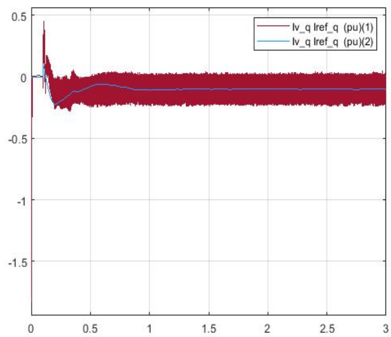
(c) Reactive power at the PCC of VSC 4



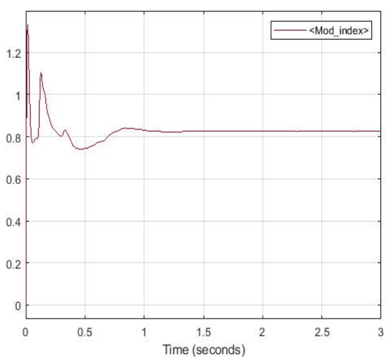
(d) Three-phase voltage and current at the PCC

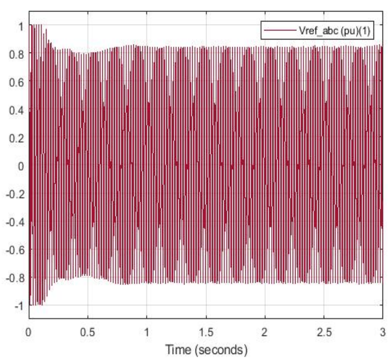
Figure A.23: PCC of VSC 4, normal operation





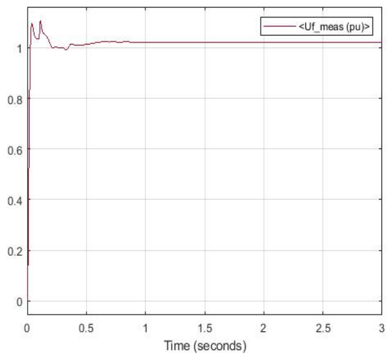
(a) d axis part of converter reactor phase current **(b)** q axis part of converter reactor phase current



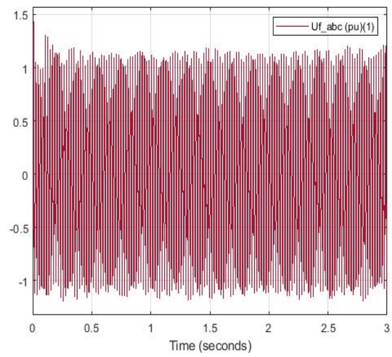


(c) Modulation index **(d)** Three-phase reference voltage

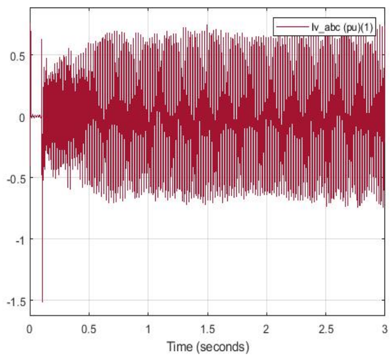
Figure A.24: Control signals of VSC 4, normal operation



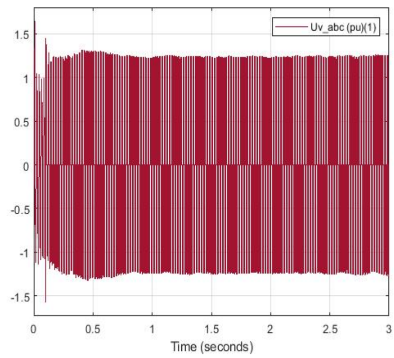
(a) Voltage on the AC filter bus of VSC 4



(b) AC voltage on the AC filter bus of VSC 4



(c) Converter reactor phase current of VSC 4



(d) Converter reactor phase voltage of VSC 4

Figure A.25: Filter bus of VSC 4, normal operation

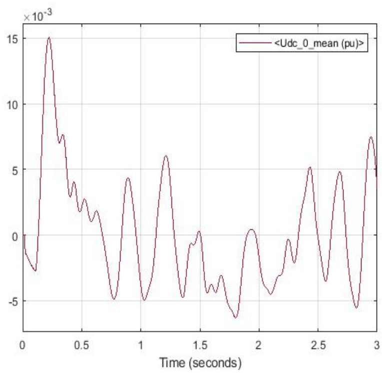
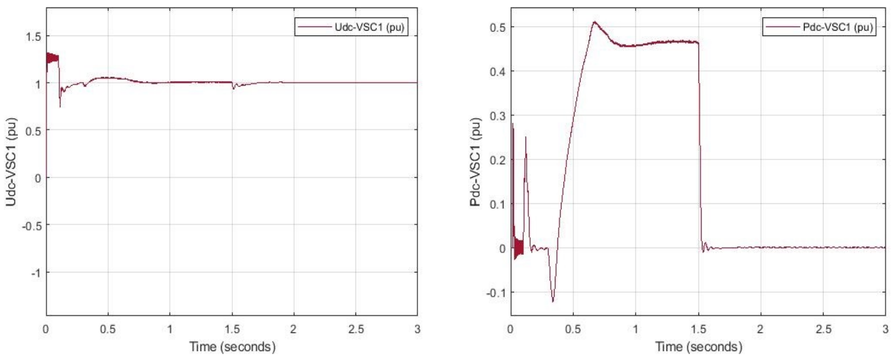


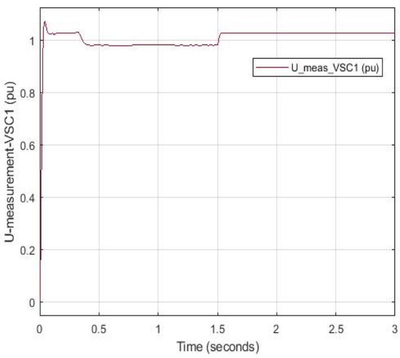
Figure A.26: Sum of the positive and negative pole voltages on the DC side of VSC 4, normal operation

Case Study 1

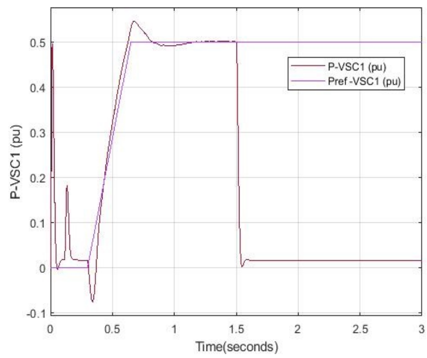


(a) DC voltage on the DC side of VSC 1 **(b)** Power on the DC side of VSC 1

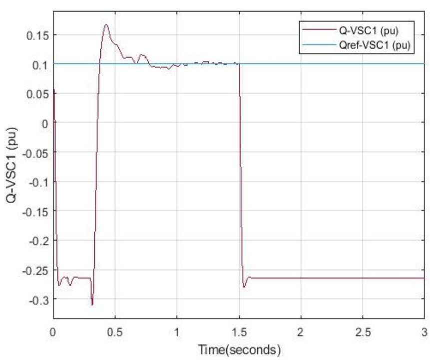
Figure A.27: DC side of VSC 1, case study 1



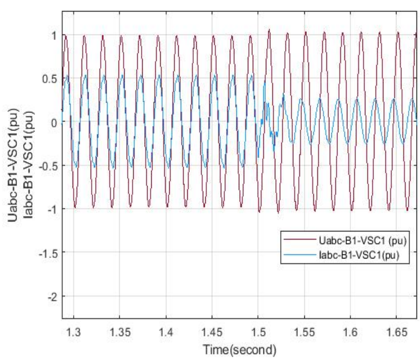
(a) AC response voltage at the PCC of VSC 1



(b) Active power at the PCC of VSC 1

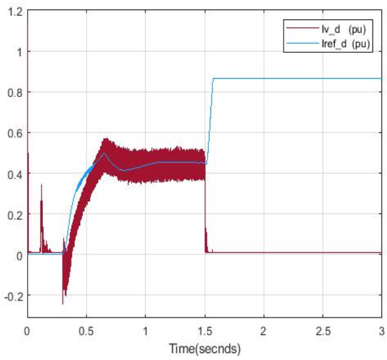


(c) Reactive power at the PCC of VSC 1

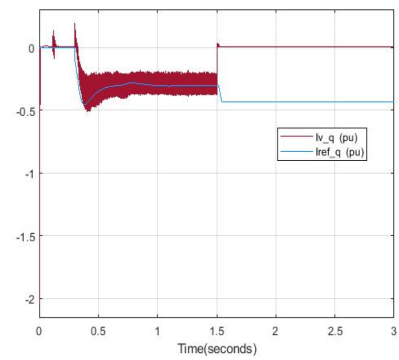


(d) Three-phase voltage and current at the PCC

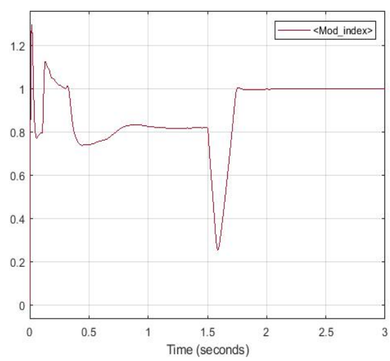
Figure A.28: PCC of VSC 1, case study 1



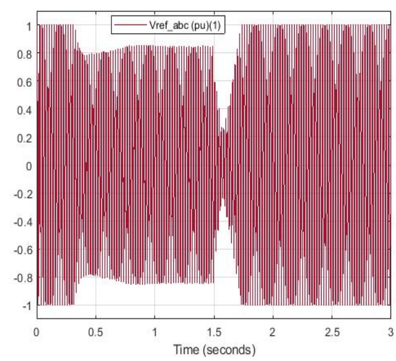
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

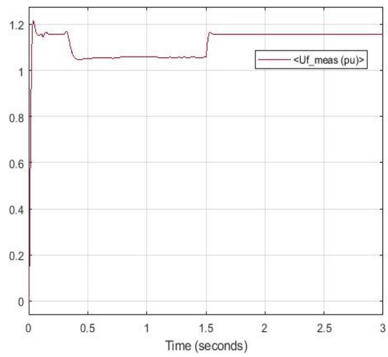


(c) Modulation index

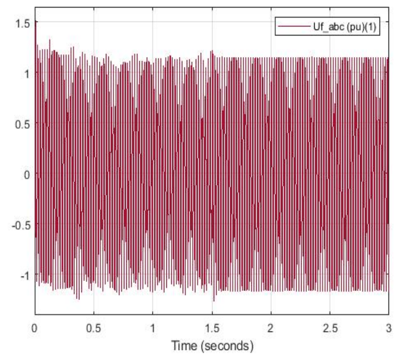


(d) Three-phase reference voltage

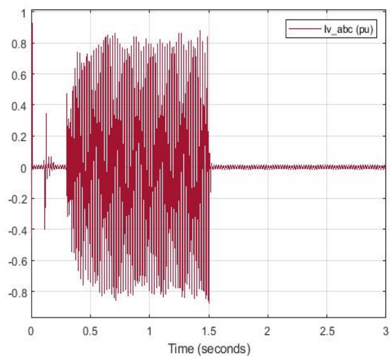
Figure A.29: Control signals of VSC 1, case study 1



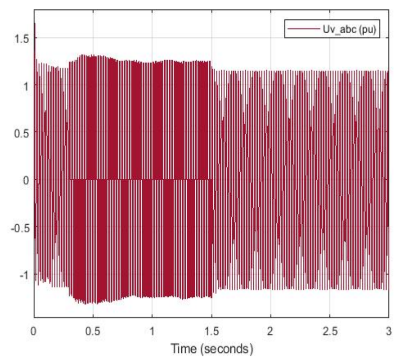
(a) Voltage on the AC filter bus of VSC 1



(b) AC voltage on the AC filter bus of VSC 1



(c) Converter reactor phase current of VSC 1



(d) Converter reactor phase voltage of VSC 1

Figure A.30: Filter bus of VSC 1, case study 1

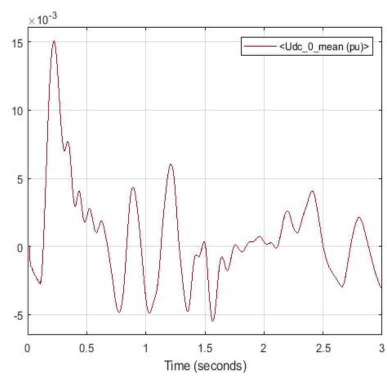
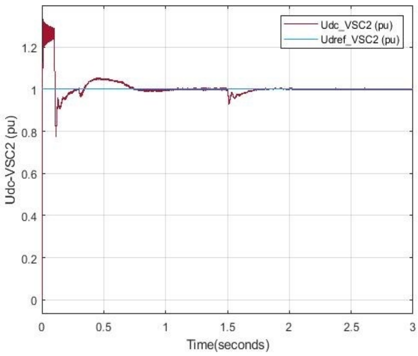
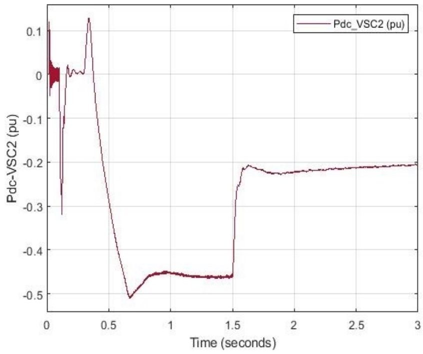


Figure A.31: Sum of the positive and negative pole voltages on the DC side of VSC 1, case study 1

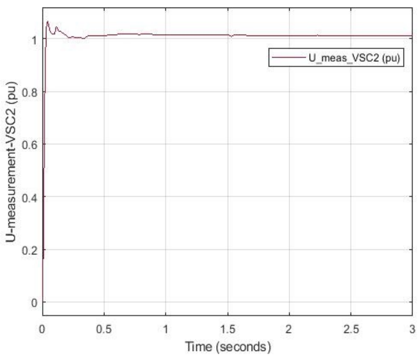


(a) DC voltage on the DC side of VSC 2

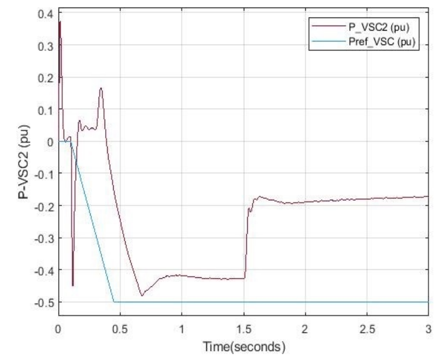


(b) Power on the DC side of VSC 2

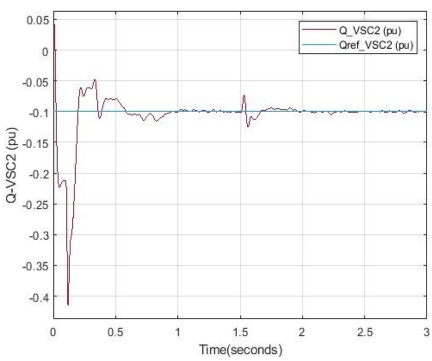
Figure A.32: DC side of VSC 2, case study 1



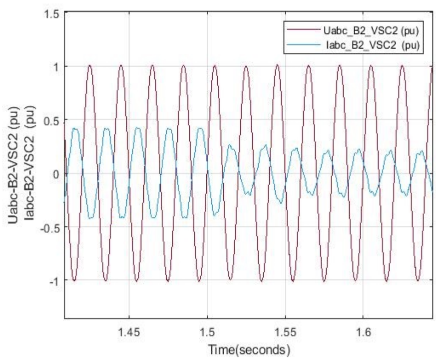
(a) AC response voltage at the PCC of VSC 2



(b) Active power at the PCC of VSC 2

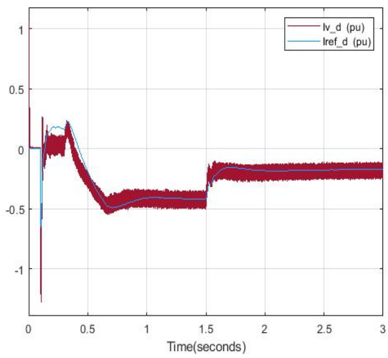


(c) Reactive power at the PCC of VSC 2

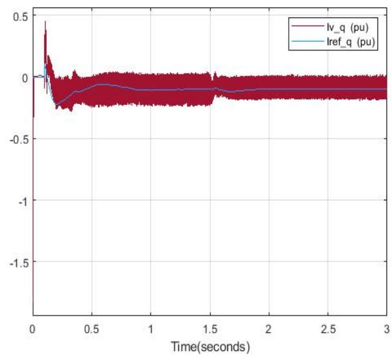


(d) Three-phase voltage and current at the PCC

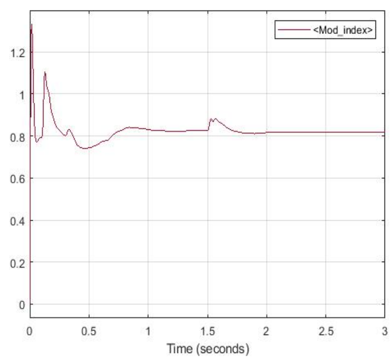
Figure A.33: PCC of VSC 2, case study 1



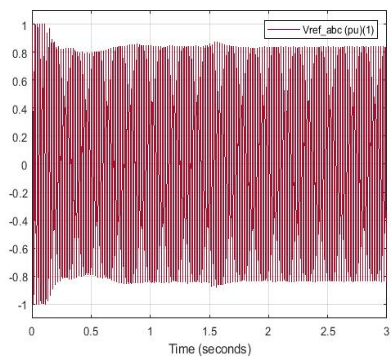
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

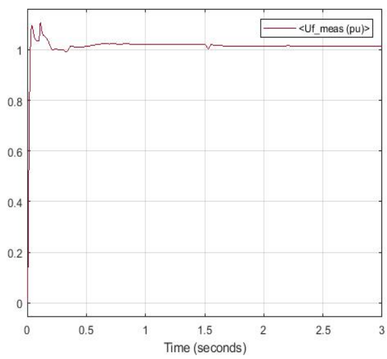


(c) Modulation index

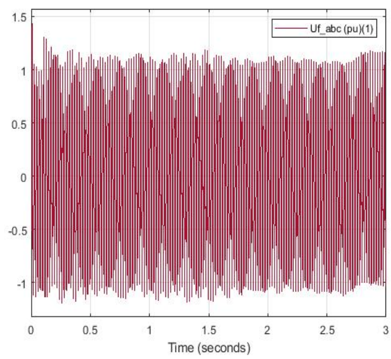


(d) Three-phase reference voltage

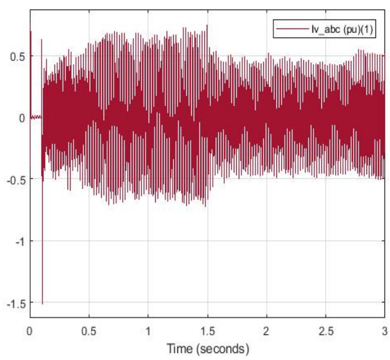
Figure A.34: Control signals of VSC 2, case study 1



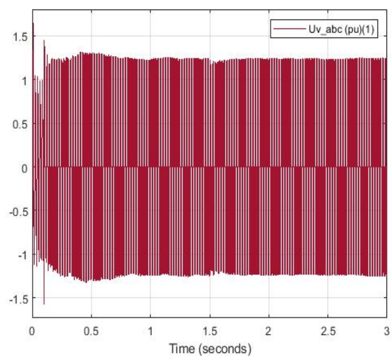
(a) Voltage on the AC filter bus of VSC 2



(b) AC voltage on the AC filter bus of VSC 2



(c) Converter reactor phase current of VSC 2



(d) Converter reactor phase voltage of VSC 2

Figure A.35: Filter bus of VSC 2, case study 1

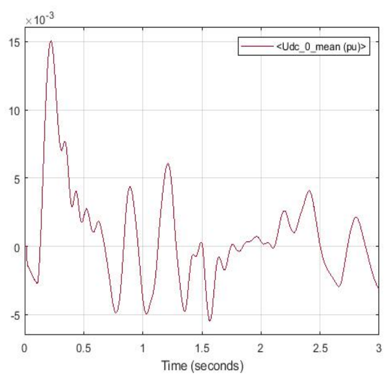
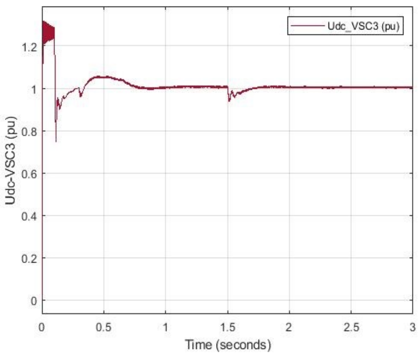
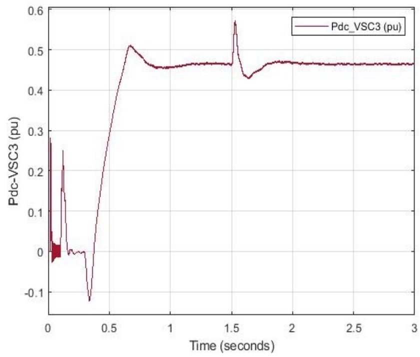


Figure A.36: Sum of the positive and negative pole voltages on the DC side of VSC 2, case study 1

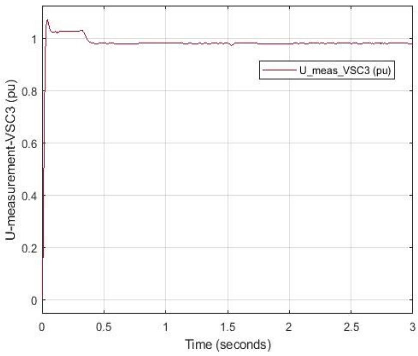


(a) DC voltage on the DC side of VSC 3

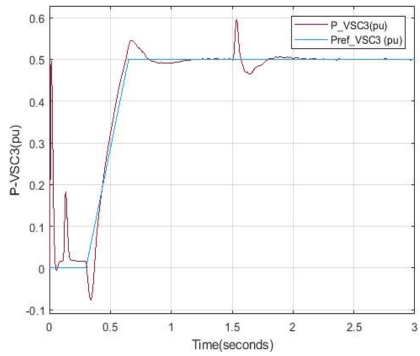


(b) Power on the DC side of VSC 3

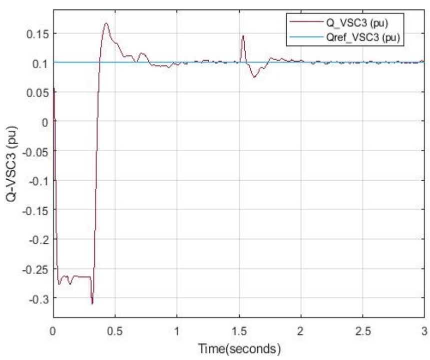
Figure A.37: DC side of VSC 3, case study 1



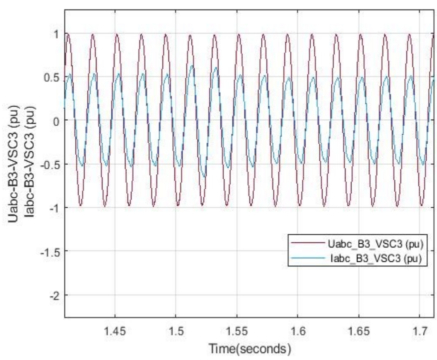
(a) AC response voltage at the PCC of VSC 3



(b) Active power at the PCC of VSC 3

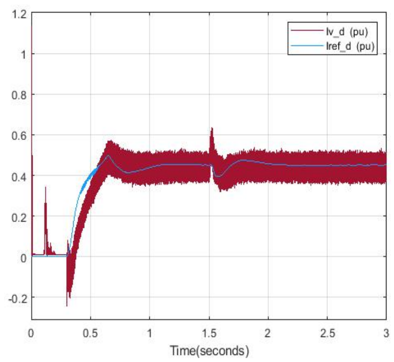


(c) Reactive power at the PCC of VSC 3

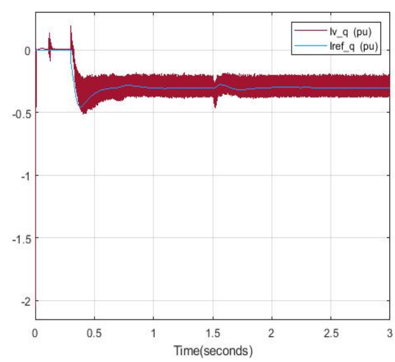


(d) Three-phase voltage and current at the PCC

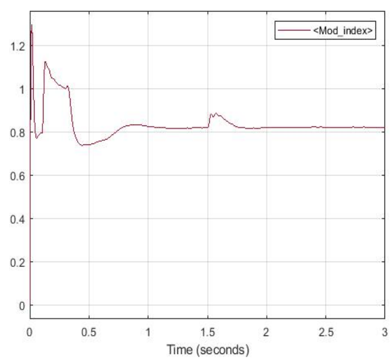
Figure A.38: PCC of VSC 3, case study 1



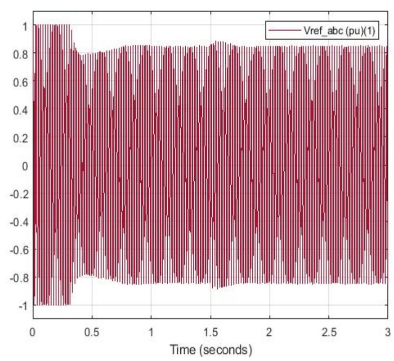
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

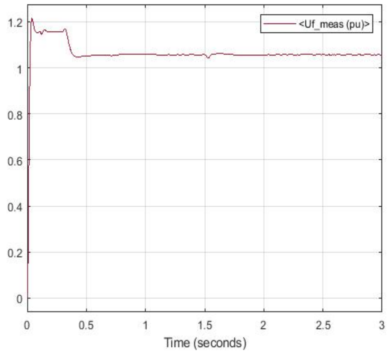


(c) Modulation index

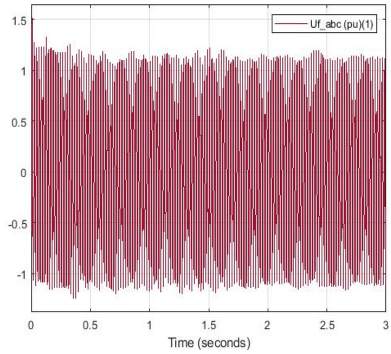


(d) Three-phase reference voltage

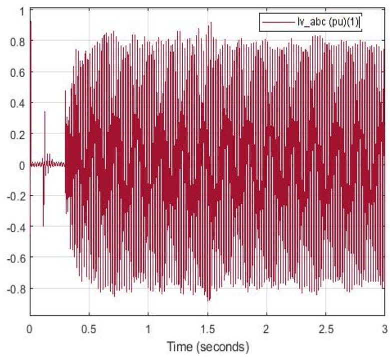
Figure A.39: Control signals of VSC 3, case study 1



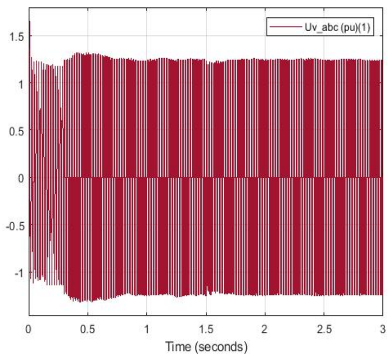
(a) Voltage on the AC filter bus of VSC 3



(b) AC voltage on the AC filter bus of VSC 3



(c) Converter reactor phase current of VSC 3



(d) Converter reactor phase voltage of VSC 3

Figure A.40: Filter bus of VSC 3, case study 1

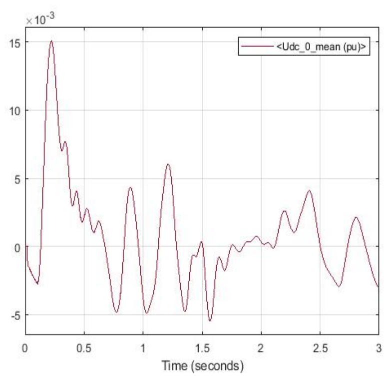
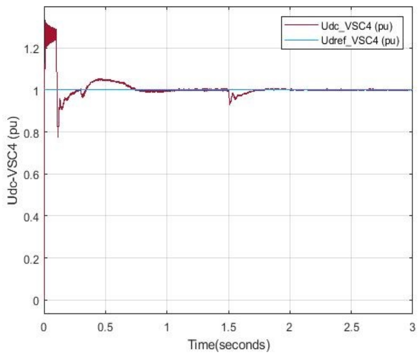
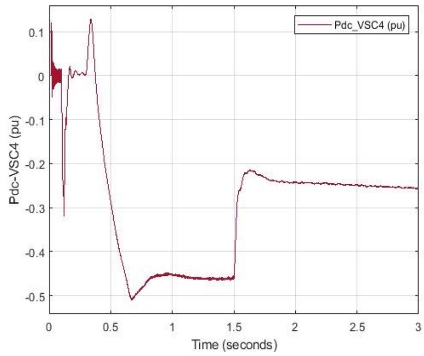


Figure A.41: Sum of the positive and negative pole voltages on the DC side of VSC 3, case study 1

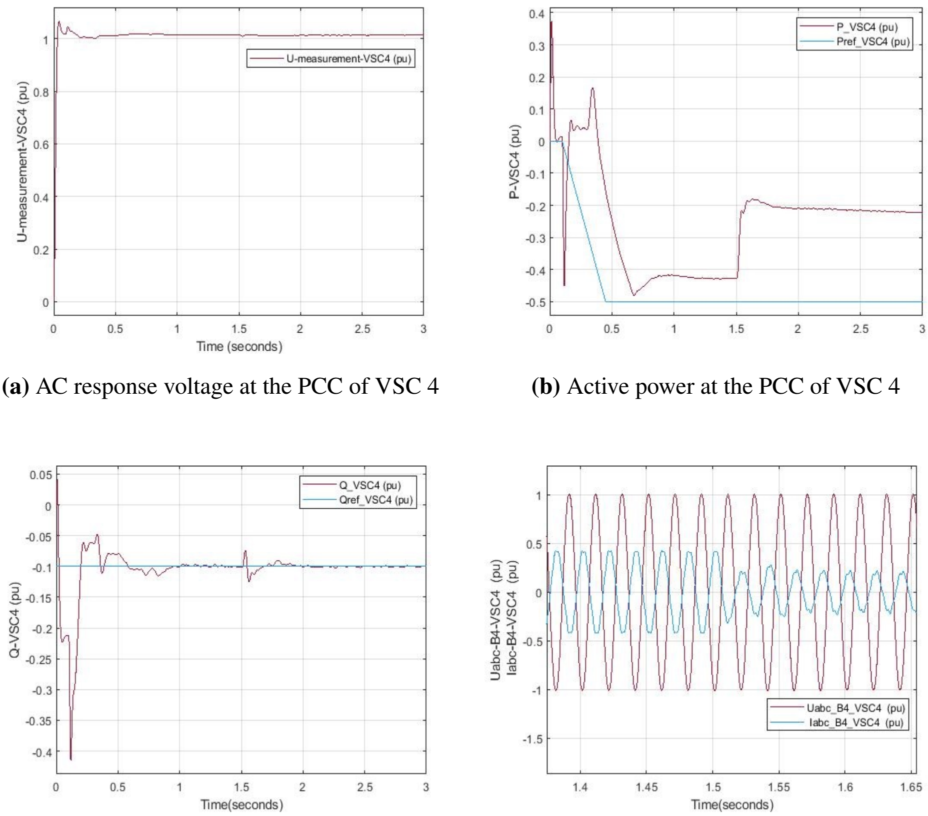


(a) DC voltage on the DC side of VSC 4



(b) Power on the DC side of VSC 4

Figure A.42: DC side of VSC 4, case study 1



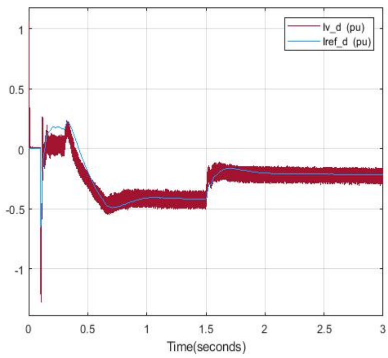
(a) AC response voltage at the PCC of VSC 4

(b) Active power at the PCC of VSC 4

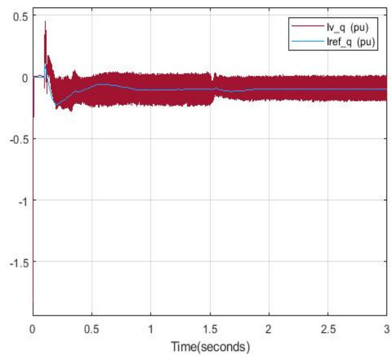
(c) Reactive power at the PCC of VSC 4

(d) Three-phase voltage and current at the PCC

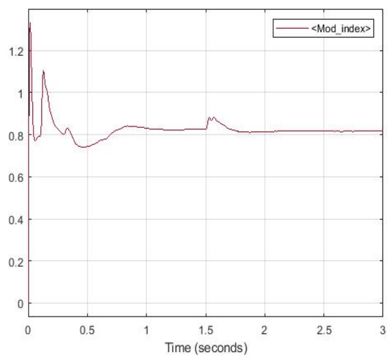
Figure A.43: PCC of VSC 4, case study 1



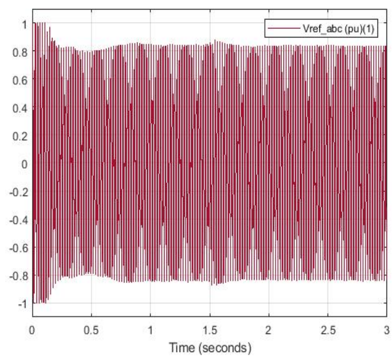
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

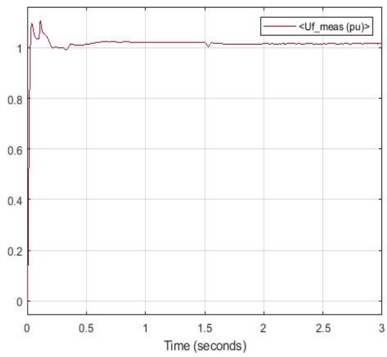


(c) Modulation index

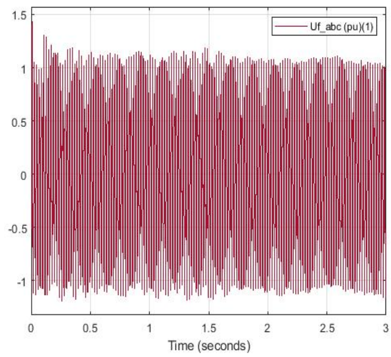


(d) Three-phase reference voltage

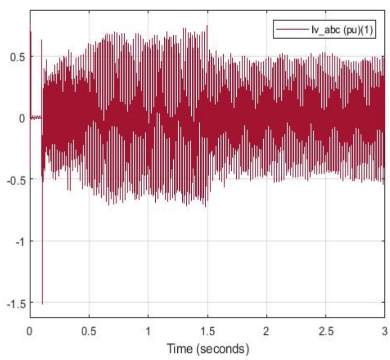
Figure A.44: Control signals of VSC 4, case study 1



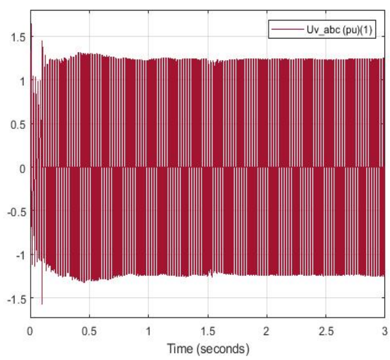
(a) Voltage on the AC filter bus of VSC 4



(b) AC voltage on the AC filter bus of VSC 4



(c) Converter reactor phase current of VSC 4



(d) Converter reactor phase voltage of VSC 4

Figure A.45: Filter bus of VSC 4, case study 1

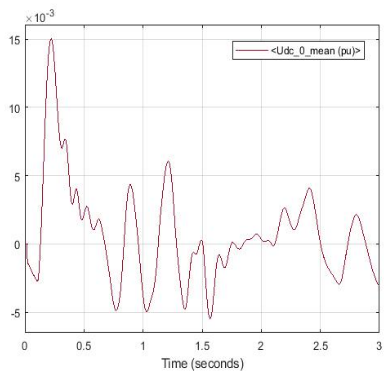
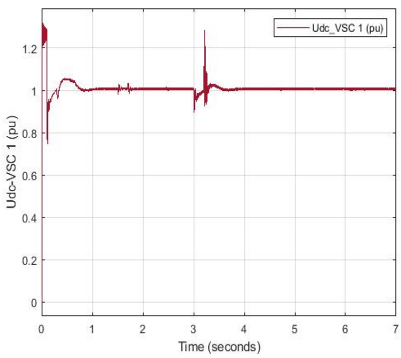
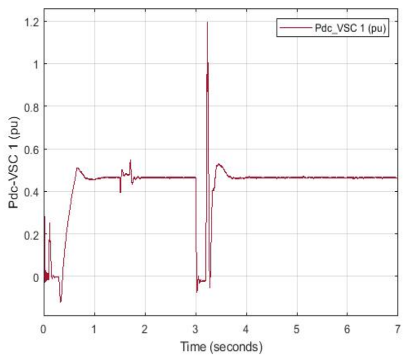


Figure A.46: Sum of the positive and negative pole voltages on the DC side of VSC 4, case study 1

Case Study 2

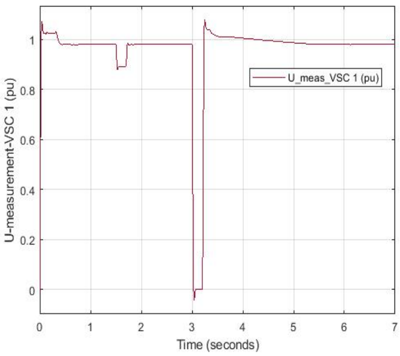


(a) DC voltage on the DC side of VSC 1

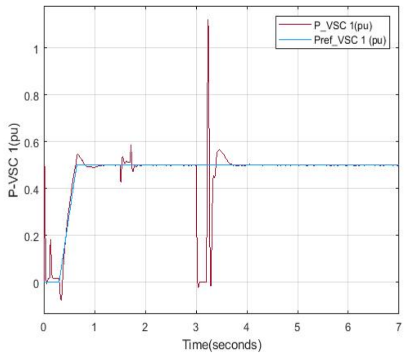


(b) Power on the DC side of VSC 1

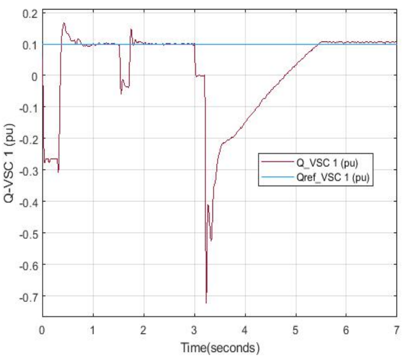
Figure A.47: DC side of VSC 1, case study 2



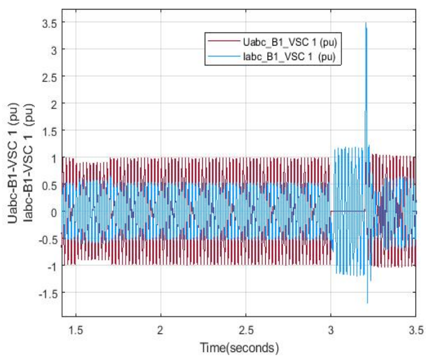
(a) AC response voltage at the PCC of VSC 1



(b) Active power at the PCC of VSC 1

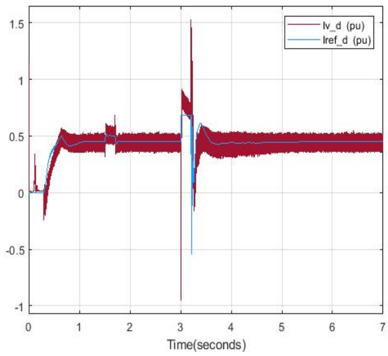


(c) Reactive power at the PCC of VSC 1

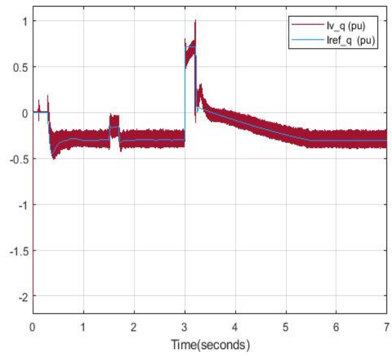


(d) Three-phase voltage and current at the PCC

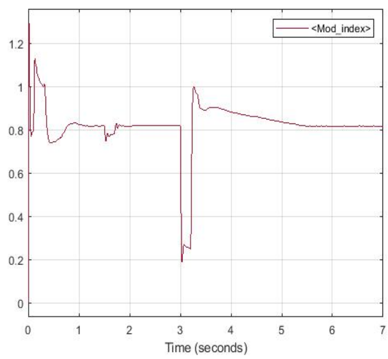
Figure A.48: PCC of VSC 1, case study 2



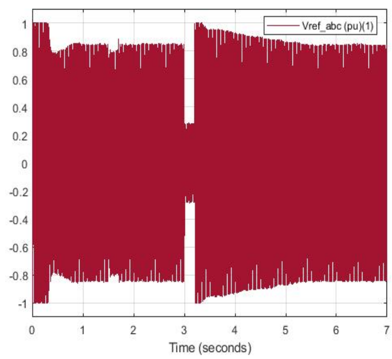
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

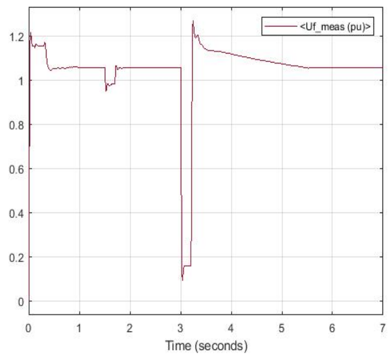


(c) Modulation index

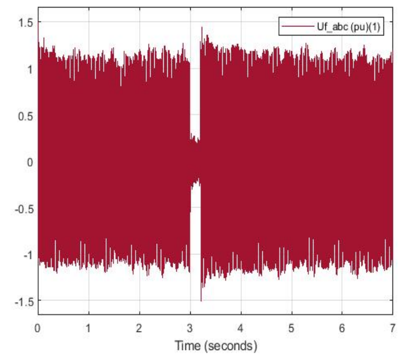


(d) Three-phase reference voltage

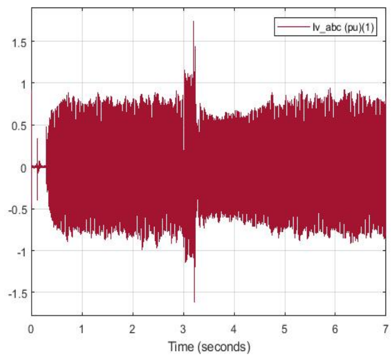
Figure A.49: Control signals of VSC 1, case study 2



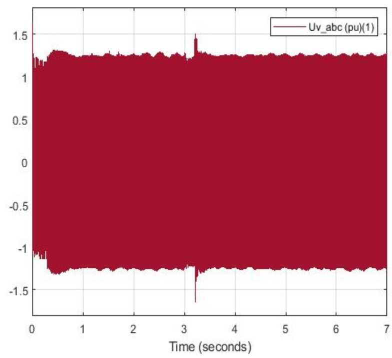
(a) Voltage on the AC filter bus of VSC 1



(b) AC voltage on the AC filter bus of VSC 1



(c) Converter reactor phase current of VSC 1



(d) Converter reactor phase voltage of VSC 1

Figure A.50: Filter bus of VSC 1, case study 2

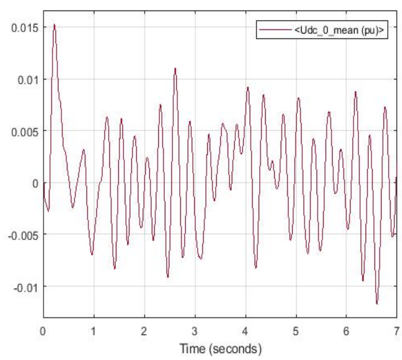
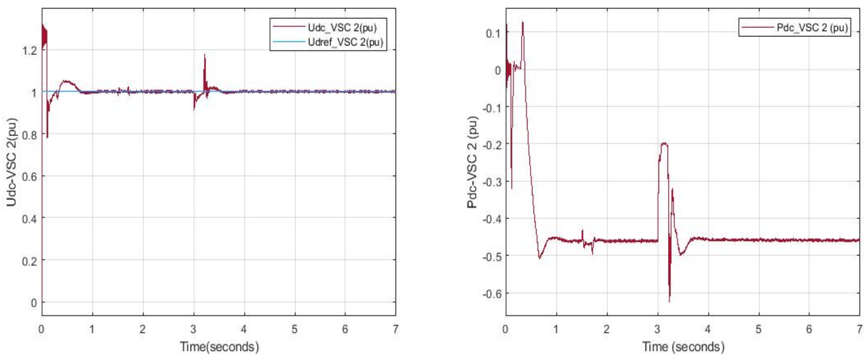
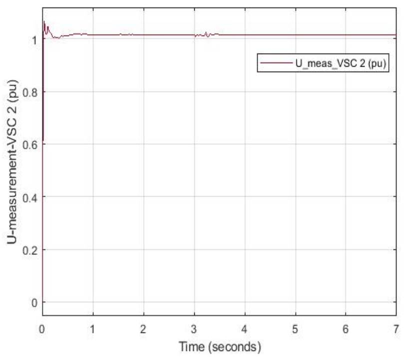


Figure A.51: Sum of the positive and negative pole voltages on the DC side of VSC 1, case study 2

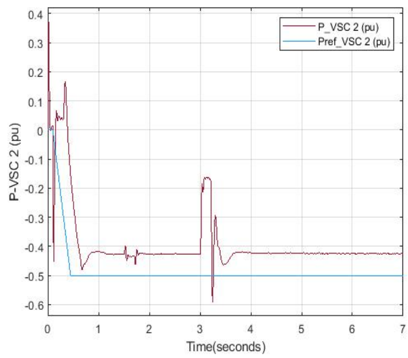


(a) DC voltage on the DC side of VSC 2 **(b)** Power on the DC side of VSC 2

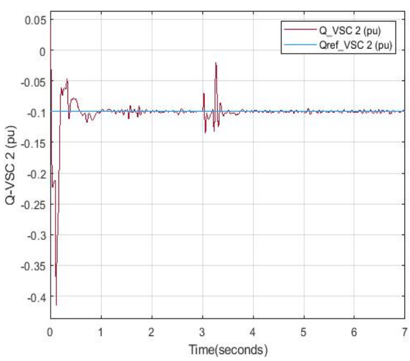
Figure A.52: DC side of VSC 2, case study 2



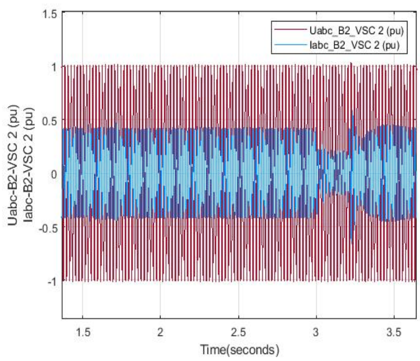
(a) AC response voltage at the PCC of VSC 2



(b) Active power at the PCC of VSC 2

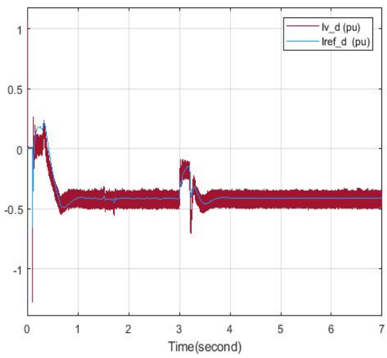


(c) Reactive power at the PCC of VSC 2

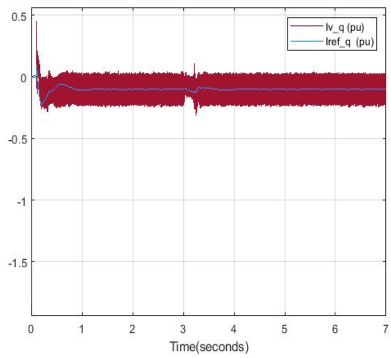


(d) Three-phase voltage and current at the PCC

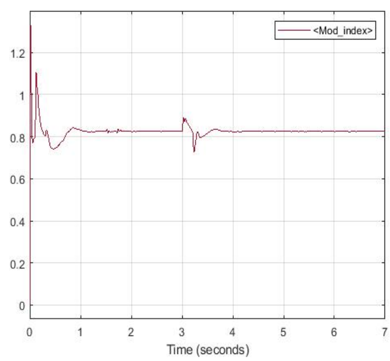
Figure A.53: PCC of VSC 2, case study 2



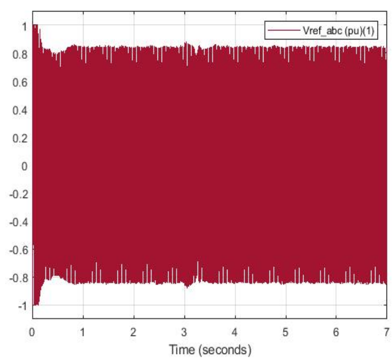
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

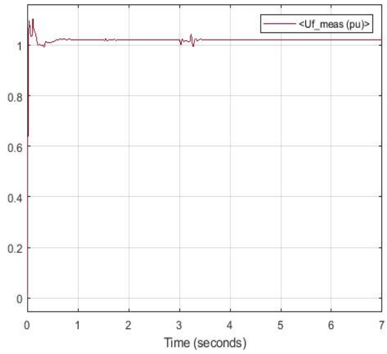


(c) Modulation index

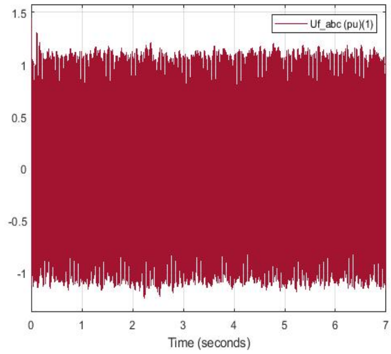


(d) Three-phase reference voltage

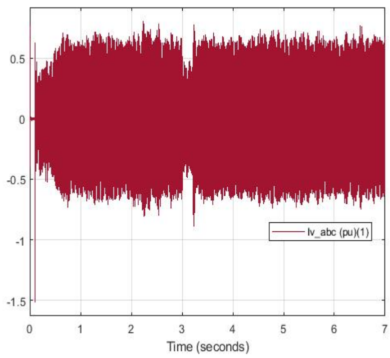
Figure A.54: Control signals of VSC 2, case study 2



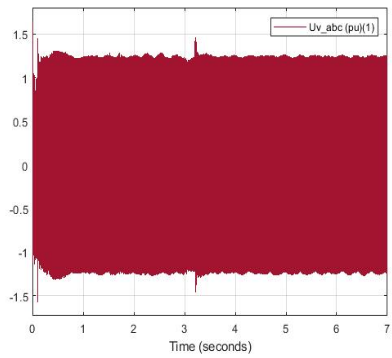
(a) Voltage on the AC filter bus of VSC 2



(b) AC voltage on the AC filter bus of VSC 2



(c) Converter reactor phase current of VSC 2



(d) Converter reactor phase voltage of VSC 2

Figure A.55: Filter bus of VSC 2, case study 2

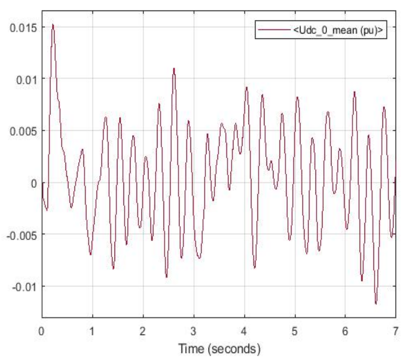
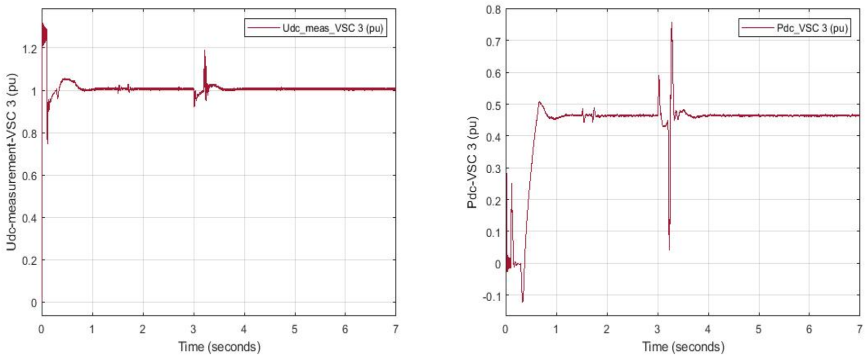
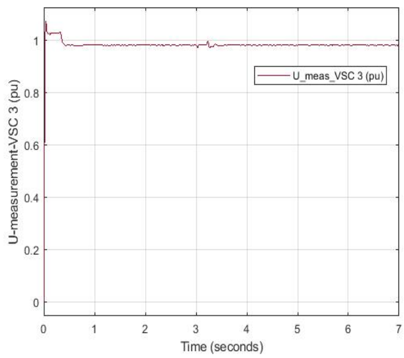


Figure A.56: Sum of the positive and negative pole voltages on the DC side of VSC 2, case study 2

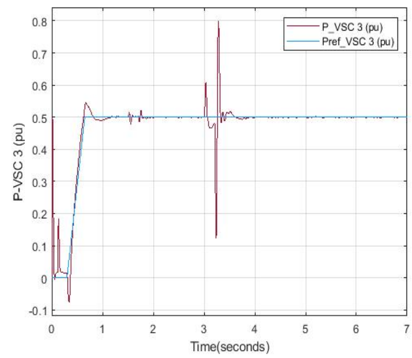


(a) DC voltage on the DC side of VSC 3 **(b)** Power on the DC side of VSC 3

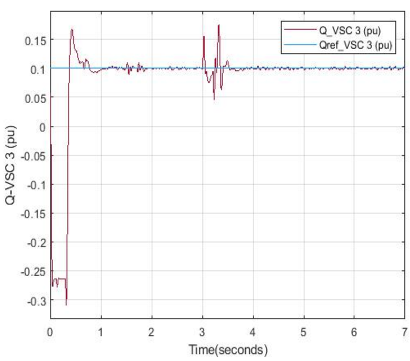
Figure A.57: DC side of VSC 3, case study 2



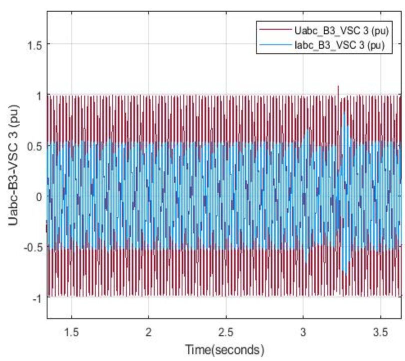
(a) AC response voltage at the PCC of VSC 3



(b) Active power at the PCC of VSC 3

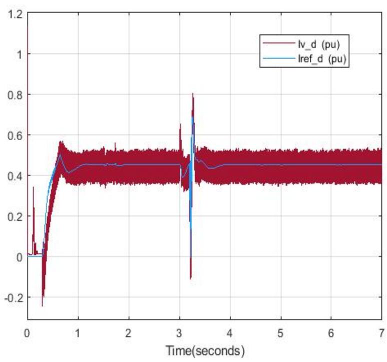


(c) Reactive power at the PCC of VSC 3

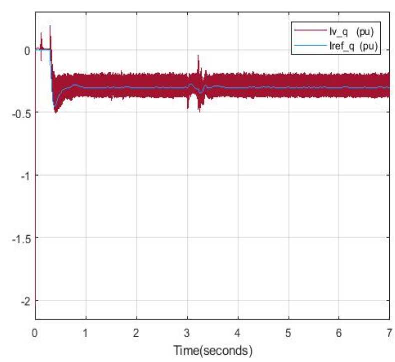


(d) Three-phase voltage and current at the PCC

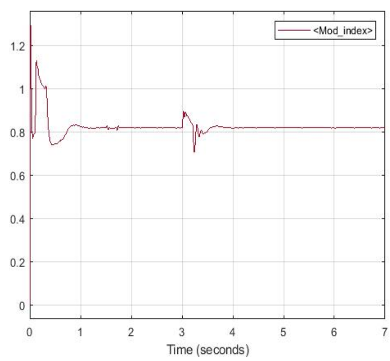
Figure A.58: PCC of VSC 3, case study 2



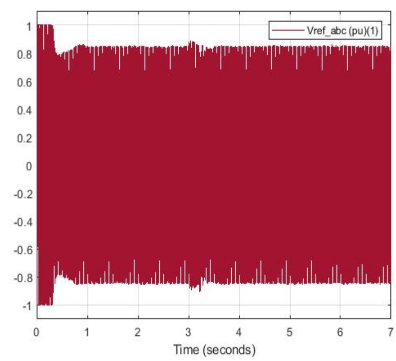
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

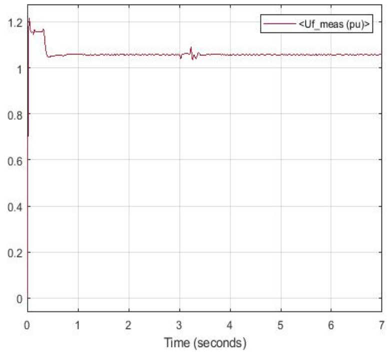


(c) Modulation index

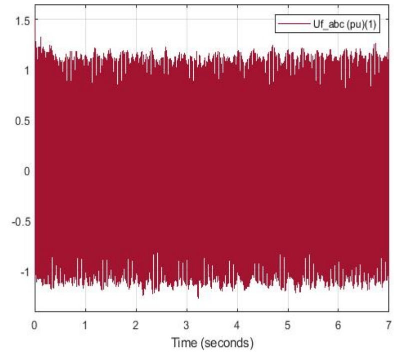


(d) Three-phase reference voltage

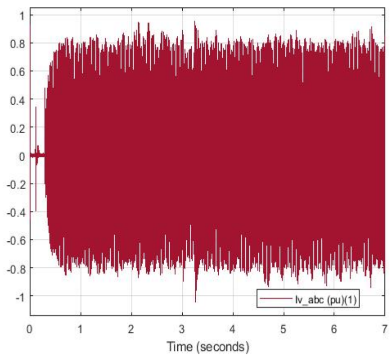
Figure A.59: Control signals of VSC 3, case study 2



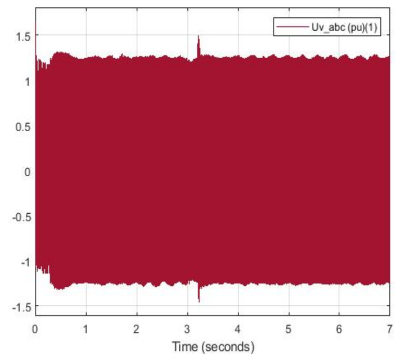
(a) Voltage on the AC filter bus of VSC 3



(b) AC voltage on the AC filter bus of VSC 3



(c) Converter reactor phase current of VSC 3



(d) Converter reactor phase voltage of VSC 3

Figure A.60: Filter bus of VSC 3, case study 2

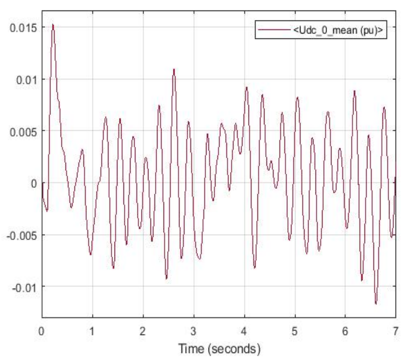
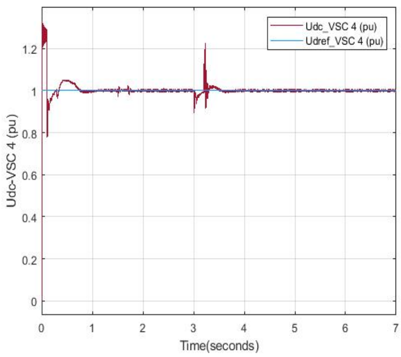
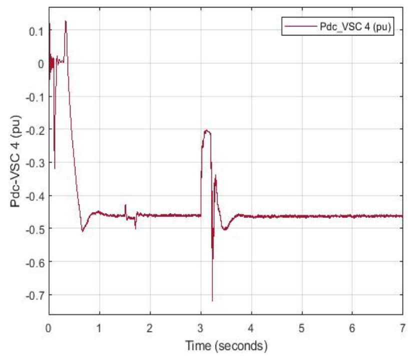


Figure A.61: Sum of the positive and negative pole voltages on the DC side of VSC 3, case study 2

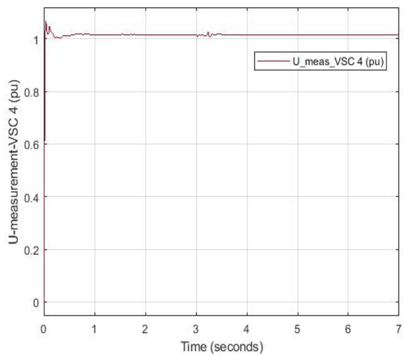


(a) DC voltage on the DC side of VSC 4

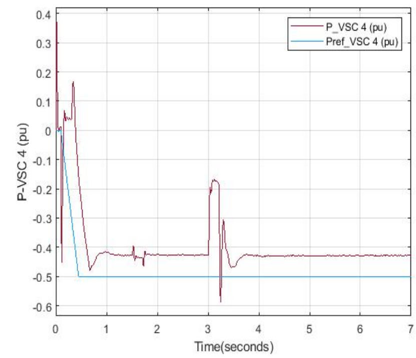


(b) Power on the DC side of VSC 4

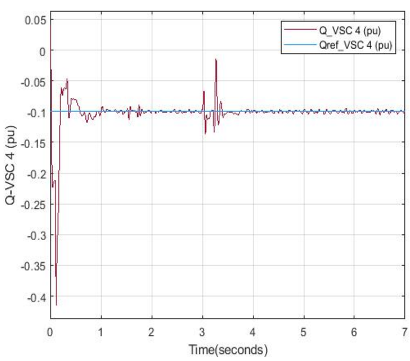
Figure A.62: DC side of VSC 4, case study 2



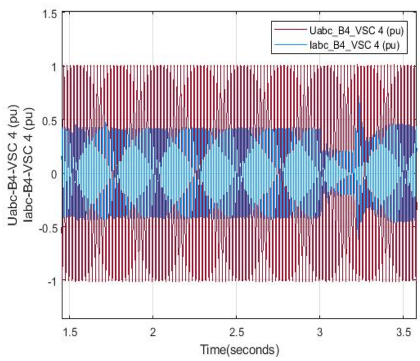
(a) AC response voltage at the PCC of VSC 4



(b) Active power at the PCC of VSC 4

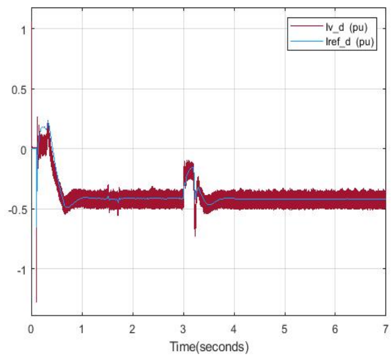


(c) Reactive power at the PCC of VSC 4

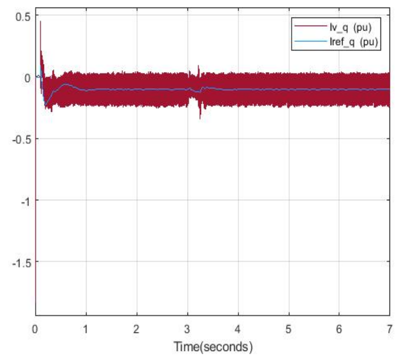


(d) Three-phase voltage and current at the PCC

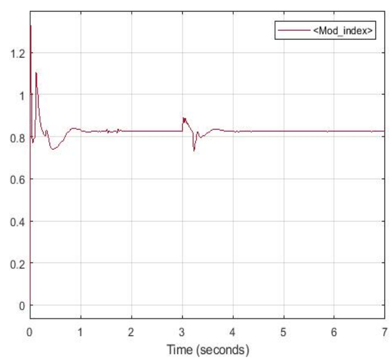
Figure A.63: PCC values of VSC 4, case study 2



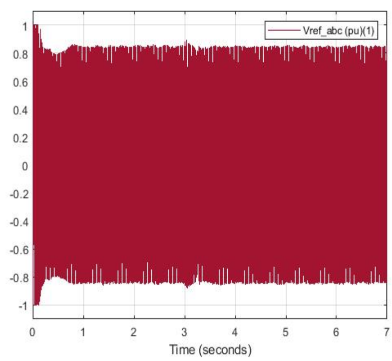
(a) d axis part of converter reactor phase current



(b) q axis part of converter reactor phase current

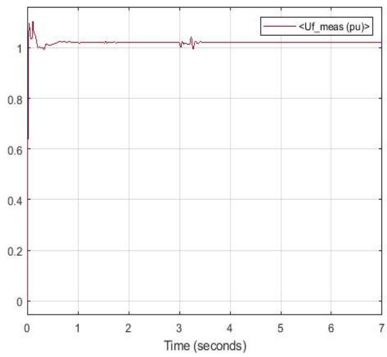


(c) Modulation index

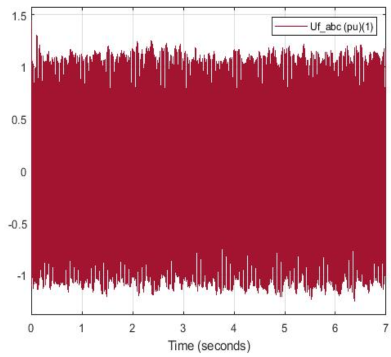


(d) Three-phase reference voltage

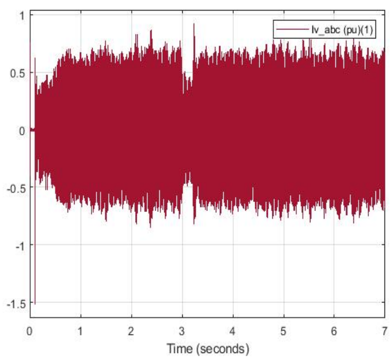
Figure A.64: Control signals of VSC 4, case study 2



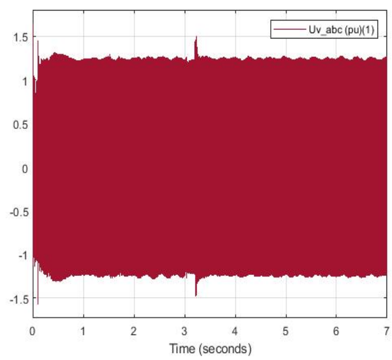
(a) Voltage on the AC filter bus of VSC 4



(b) AC voltage on the AC filter bus of VSC 4



(c) Converter reactor phase current of VSC 4



(d) Converter reactor phase voltage of VSC 4

Figure A.65: Filter bus of VSC 4, case study 2

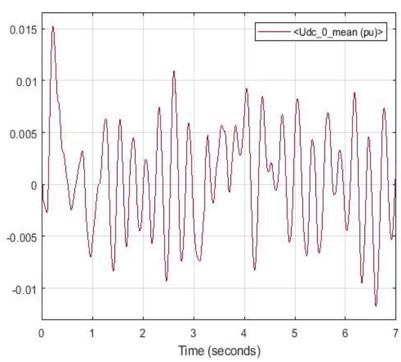


Figure A.66: Sum of the positive and negative pole voltages on the DC side of VSC 4, case study 2