

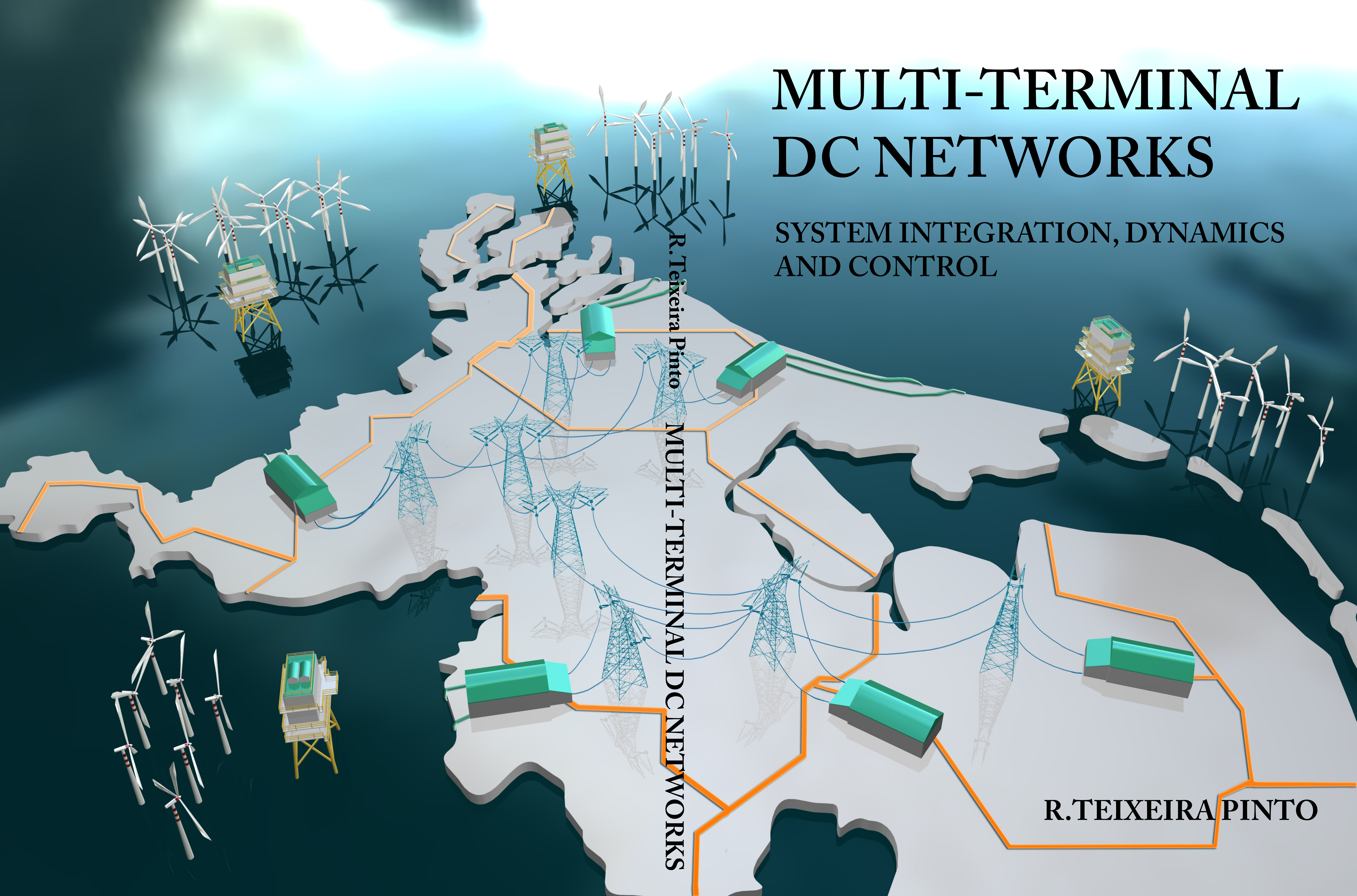
MULTI-TERMINAL DC NETWORKS

SYSTEM INTEGRATION, DYNAMICS
AND CONTROL

R. Teixeira Pinto

MULTI-TERMINAL DC NETWORKS

R. TEIXEIRA PINTO



Propositions

Accompanying the Ph.D. Thesis
Multi-Terminal DC Networks System Integration, Dynamics and Control
R.Teixeira Pinto

1. All the necessary technology for large scale adoption of high-voltage multi-terminal dc networks is currently available. What are still missing is political will, and correct economic incentives.
2. Power electronic converters provide fast dynamic response for multi-terminal dc networks. Therefore, in the future, more attention should be given to strengthening ac networks that are connected to dc networks.
3. The first commandment of HVdc engineers is: *"Thou shall not rely on communication"*. To control the power flow in multi-terminal dc networks, the first commandment should be changed to: *"Thou shall guarantee stability if communication fails"*.
4. The introduction of an electrical network control which is not based on droop control – also called proportional control – faces resistance purely for breaking with tradition.
5. Deregulation of the electrical power industry shifted the focus of power system engineers from electric current flow to cash flow. Currently, 1.3 billion people lack access to electricity worldwide.
6. Bulk electricity storage is the holy grail for electrical engineering.
7. To counteract a growing tendency of applying complex models to simple problems, Occam's razor – *lex parsimoniae* – should be taught at university.
8. The word professor is derived from the Latin word *profitēri*, i.e. to openly declare or publicly teach. Therefore, more focus should be given in developing teaching skills during a doctoral program.
9. Brazil ought to be working on solving its rampant inequality problems instead of volunteering to host Fifa's World Cup and IOC's Summer Olympic Games.
10. The fractional reserve banking system is unfair because it frees economists from the annoying conservation laws of physics.

These propositions are regarded as opposable and defendable, and have been approved as such by the promoter, Prof. dr. ir. J.A. Ferreira.

Stellingen

Behorende bij het proefschrift
Multi-Terminal DC Networks System Integration, Dynamics and Control.
R. Teixeira Pinto

1. Alle technologieën nodig voor de grootschalige toepassing van multi-terminal hoogspannings-dc-netwerken zijn momenteel beschikbaar. Wat nog ontbreekt zijn politieke wil en de juiste economische drijfveren.
2. Vermogenselektronische omvormers bieden goed dynamisch gedrag voor multi-terminal dc-netwerken. In de toekomst zou daarom meer aandacht besteed moeten worden aan het versterken van ac-netwerken die zijn verbonden met de dc-netwerken.
3. Het eerste gebod van HVdc-ingenieurs is: *“Gij zult niet vertrouwen op communicatie”*. Om de vermogensstromen in multi-terminal dc-netwerken te sturen, zou het eerste gebod veranderd moeten worden in: *“Gij zult stabiliteit garanderen wanneer communicatie faalt”*.
4. De introductie van een regelstrategie voor elektrische netwerken niet gebaseerd op droop-regeling – ook bekend als proportionele regeling – stuit alleen op weerstand omdat het breekt met traditie.
5. Deregulering van de elektriciteitssector heeft de aandacht van netbeheerders verschoven van elektrische stromen naar geldstromen. Momenteel hebben 1,3 miljard mensen wereldwijd geen toegang tot elektriciteit.
6. Grootschalige opslag van elektriciteit is de heilige graal voor de elektrotechniek.
7. Om de groeiende tendens van het toepassen van complexe modellen op eenvoudige problemen tegen te gaan, zou Ockhams scheermes – *lex parsimoniae* – onderwezen moeten worden op universiteiten.
8. Het woord professor is afgeleid van het Latijnse woord *profitēri*, met oorspronkelijke betekenis *diegene die de professie van het openbare lesgeven uitoefent*. Het ontwikkelen van onderwijsvaardigheden dient daarom meer aandacht te krijgen in promotieprogramma's.
9. Brazilië zou moeten werken aan het oplossen van zijn welig tierende ongelijkheidsproblemen in plaats van het Fifa wereldkampioenschap voetbal en de Olympische zomerspelen te organiseren.
10. Fractional reserve banking is oneerlijk omdat het economen bevrijdt van de hinderlijke natuurkundige behoudswetten.

Deze stellingen worden opponeerbaar en verdedigbaar geacht en zijn als zodanig goedgekeurd door de promotor, prof. dr. ir. J.A. Ferreira.

RODRIGO TEIXEIRA PINTO

MULTI-TERMINAL DC NETWORKS

SYSTEM INTEGRATION, DYNAMICS
AND CONTROL

MULTI-TERMINAL DC NETWORKS

SYSTEM INTEGRATION, DYNAMICS AND CONTROL

Proefschrift

ter verkrijging van de graad van doctor
aan de Technische Universiteit Delft,
op gezag van de Rector Magnificus prof.ir. K.C.A.M. Luyben,
voorzitter van het College voor Promoties,
in het openbaar te verdedigen

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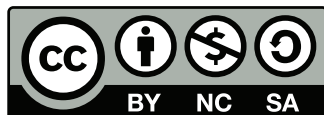
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*It is like watching giants wake up,
delicately share a cup of tea on a windy day,
and then go back to sleep.
All without tripping.*

Barry Rawn.

*Alla mia sposa,
Francesca,*

*senza la quale,
questo non sarebbe
né iniziato
né finito;*

&

*À minha mãe,
Audrey,*

*a qual
sempre quis
ter um Doutor
na família.*

Summary

At the same time that the world population increases, urbanisation processes intensify and economies grow, electricity supply is becoming ever more important, as energy is a key component to modern societies. Still, more than eighty percent of the primary energy consumed worldwide, and more than fifty percent of all generated electricity, comes from fossil-fuel power plants.

When large amounts of electricity need to be transported for long distances, or when underground or submarine cables are involved, using direct current high-voltage transmission systems is more efficient and cost effective than using traditional high-voltage alternating current transmission.

Therefore, the main thesis objective is to study to what extent can multi-terminal dc networks provide an optimal platform to foster the integration of remotely located renewable resources, with particular focus on the integration of offshore wind farms in the North Sea.

In this thesis, five main challenges were identified before high-voltage multi-terminal dc networks – which can promote the inclusion of remotely located renewable sources while strengthening the existing ac power system networks – can finally become widespread: *system integration, power flow control, dynamic behaviour, stability and fault behaviour*.

These challenges are investigated through a comprehensive literature review, a series of detailed simulation models, and an experimental laboratory setup of a three-node multi-terminal dc network.

A thorough literature review of high-voltage direct current transmission systems helped establishing that modular-multilevel voltage-source converters are currently the best HVdc technology option for the development of a multi-terminal dc network in the North Sea. Additionally, a symmetric monopolar grid with a parallel-radial topology will, initially, be the best configuration, as it allows the system to develop modularly, keeps initial capital costs down, and makes it easier to face dc faults. Future multi-terminal dc networks, such as the future North Sea Transnational Grid, will have to be built modularly. Thus, standardisation – through the development of dc grid codes – will play a key role in the network development.

Regarding the network operation, the power flow in a multi-terminal dc network depends on the generation level, and on the direct voltage of its slack nodes, i.e. nodes actively controlling the multi-terminal dc network voltage. A multiple slack-node dc load flow algorithm demonstrated that better results, both in terms of N-1 network security and transmission losses, are obtained when more system nodes are functioning as slack nodes.

However, load flow algorithms cannot provide information on the dynamic behaviour of a system and, therefore, a modular dynamic model of the complete multi-terminal dc network was developed in this thesis. When building models to study the combined dynamic of large systems, such as the North Sea Transnational Grid, rather than focusing on having detailed models of each system module beforehand, the most important is to identify where the interfaces between the modules lie, and how the different system modules interact. Special attention was given to modelling the main components and control structure of voltage-source converters as, similarly to ac networks where the dynamic behaviour is mostly dictated by synchronous generators, the dynamic behaviour of multi-terminal dc networks greatly depends on its power electronics converters.

To successfully control multi-terminal dc networks a control strategy must have: fast dynamic behaviour;

high flexibility in implementing different load flow dispatch schemes; high expandability and; if possible, low communication requirements. Four commonly used control strategies to control high-voltage direct current transmission systems – droop control, ratio control, priority control and voltage margin method control – were compared according to the aforementioned performance criteria. Simulation results from the dynamic models showed that these control methods are not suitable for multi-terminal dc networks, mainly because they are difficult to expand to networks with a high number of nodes, and specially because they lack the flexibility to control the dc network power flow.

Hence, a novel strategy to control the power flow in multi-terminal dc networks – called *Distributed Voltage Control* – was developed in this thesis. With expandability and flexibility as its prime objective, the distributed voltage control strategy works by finding a solution to an optimal power flow problem and later assigning voltage references to multi-terminal dc network nodes working as slack nodes.

The development of multi-terminal dc networks will require that the system sustains control, and safe operation, under normal and contingency situations. Three different simulation case studies demonstrated that the power flow in large multi-terminal dc networks can be reliably and safely controlled, with good dynamic performance, using the distributed voltage control strategy even in case one of the connected ac networks faces a contingency.

However, the ability of a multi-terminal dc network to withstand and recover from faults in the connected ac systems – without halting its operation – can be considerably strangled by too stringent ac grid code requirements, specially if the voltage-source converters need to fully supply rated reactive current during voltage dips.

Regarding dc contingencies, hitherto the best strategy is to build the multi-terminal dc network using a symmetric monopolar configuration, and include dc limiting reactors, since the dc circuit breaker technologies which are fast enough to avoid interruption of the multi-terminal dc network operation still need to improve their current and voltage ratings before they can be used in practice.

Overall, the transient stability of multi-terminal dc networks is more concerning than its small-signal stability. Results from a small-signal stability analysis have shown that dc networks are always marginally stable systems, and that feedback control of the system direct voltages is necessary to improve stability. A small-signal model of voltage-source converters evidenced that its eigenvalues are resilient from parametric variations in the values of its hardware components, such as the LCL-filter and dc output capacitor. Additionally, the converter small-signal model was used to optimise the converter control tested in the laboratory.

In the experimental setup, three voltage-source converters were successfully operated in a parallel-radial multi-terminal dc network with a symmetric monopolar configuration. The dc network development followed an organic growth: first one converter was tested as a STATCOM, and the developed non-linear and small-signal dynamic models were validated, as the simulation results displayed a very good agreement with the experimental measurements. Afterwards, two converters were connected in back-to-back and, finally, three converters were connected in a multi-terminal dc network.

Lastly, a real-time digital simulator was used to emulate the behaviour of an offshore wind farm. Real measurements from the Dutch offshore wind farm *Egmond aan Zee* were used to validate the distributed voltage control strategy, which successfully controlled the power flow inside the three-terminal low-voltage dc network with high overall precision, while providing the complete system with a very good dynamic response. Recommendations on ways to improve the precision of the distributed voltage control strategy are included in the thesis conclusions.

As future research, the low-voltage multi-terminal dc system should be further expanded to: firstly, test different dc networks configurations and topologies, such as a meshed dc network; secondly, to include other components, such as a dc-dc converter and/or a current-source converter; and thirdly, to experimentally evaluate protection measures against ac and dc contingencies.

Samenvatting

Met de toenemende wereldbevolking, sterkere verstedelijking en groeiende economieën wordt de elektriciteitsvoorziening steeds belangrijker, aangezien energie een sleutelrol speelt in moderne samenlevingen. Toch is meer dan tachtig procent van het primaire energieverbruik wereldwijd, en meer dan vijftig procent van alle opgewekte elektriciteit, afkomstig uit fossiele bronnen.

Wanneer grote hoeveelheden elektriciteit getransporteerd moeten worden over grote afstanden, of door ondergrondse kabels of zeekabels, is het gebruik van hoogspanningsgelijkstroom efficiënter en kosteneffectiever dan traditionele hoogspanningswisselstroom.

Het hoofddoel van dit proefschrift is daarom te onderzoeken in welke mate multi-terminal dc-netwerken een optimaal platform bieden voor de bevordering van de integratie van afgelegen hernieuwbare bronnen, met speciale nadruk op de integratie van offshore windparken in de Noordzee.

In dit proefschrift zijn vijf uitdagingen vastgesteld die een grootschalige toepassing van multi-terminal dc-netwerken –welke tegelijkertijd de ontsluiting van afgelegen hernieuwbare bronnen kunnen bevorderen en bestaande ac-netwerken versterken– in de weg staan: *systeemintegratie, sturing van de vermogensstromen, dynamisch gedrag, stabiliteit en fout-gedrag*.

Deze uitdagingen worden onderzocht aan de hand van een uitgebreid literatuuronderzoek, een reeks gedetailleerde simulatiemodellen en een experimentele laboratoriumopstelling van een multi-terminal dc-netwerk met drie knooppunten.

Een grondig literatuuronderzoek naar hoogspannings-gelijkstroomsystemen heeft mede onderbouwd dat modulaire multilevel-spanningsomvormers momenteel de beste HVdc-techniek zijn voor de ontwikkeling van een multi-terminal dc-netwerk in de Noordzee. Daarnaast zal een symmetrisch monopolaire netwerk met een parallelle-radiale topologie aanvankelijk de beste configuratie zijn, omdat het een modulaire ontwikkeling van het systeem mogelijk maakt, de initiële kapitale kosten laag houdt en dc-fouten beheersbaar houdt. Toekomstige multi-terminal dc-netwerken, zoals het toekomstige North Sea Transnational Grid, zullen modulair opgebouwd moeten worden. Standaardisatie –door middel van een op te stellen gelijkspanningsnetcode – zal daarom een sleutelrol vervullen in de netwerkontwikkeling.

Betreffende het functioneren van het netwerk, de vermogensstroom in multi-terminal dc-netwerken hangt af van de energieproductie en de gelijkspanning van de *slack nodes*, dat wil zeggen, knooppunten die actief de spanning regelen. Een loadflow-algoritme met meerdere *slack nodes* laat zien dat betere prestaties worden verkregen, zowel qua n-1 robuustheid als transportverliezen, wanneer meer knooppunten als *slack nodes* functioneren.

Echter, loadflow-algoritmes geven geen informatie over het dynamische gedrag van een systeem en daarom is een modulair dynamisch model van het totale multi-terminal dc-netwerk ontwikkeld in dit proefschrift. Bij het opstellen van modellen voor het gezamenlijke gedrag van grote systemen, zoals het North Sea Transnational Grid, is het afbakenen van de verschillende modules en hun onderlinge interactie bepalen, belangrijker dan het hebben van zeer accurate modellen voor elke module. Aandacht ging uit naar het modelleren van de hoofdcomponenten en regelstructuur van spanningsomvormers omdat, gelijkaardig aan ac-netwerken waar synchrone generatoren het dynamische gedrag grotendeels bepalen, vermogenselektronische-omvormers het gedrag van dc-netwerken bepalen.

Multi-terminal dc-netwerken succesvol regelen stelt de volgende eisen aan de regelstrategie: snel dynamisch gedrag; grote flexibiliteit qua implementatie van verschillende loadflow-schema's; goede uitbreidbaarheid; en, indien mogelijk, lage communicatie-eisen. Vier gangbare regelstrategieën voor de sturing van HVdc transportnetwerken –droop control, ratio control, priority control en voltage margin-control– zijn vergeleken volgens de voorgenoemde criteria. Simulatieresultaten uit de dynamische modellen lieten zien dat deze regelmethode niet geschikt zijn voor multi-terminal dc-netwerken, met name doordat netwerkbuitbreiding naar een groot aantal knooppunten moeilijk is, en daarnaast omdat de vermogensstroom niet gestuurd kan worden.

Een nieuwe strategie voor de sturing van de vermogensstroom in multi-terminal dc-netwerken – genaamd *Distributed Voltage Control*– is daarom ontwikkeld in dit proefschrift. Met uitbreidbaarheid en flexibiliteit als hoofddoel, functioneert de *Distributed Voltage Control*-strategie middels het vinden van een oplossing van een optimaal powerflow-probleem, en bepaalt spanningsreferenties voor multiterminal dc-netwerkknooppunten die als *slack nodes* werken.

De ontwikkeling van multi-terminal dc-netwerken vereist dat het systeem beheerst en veilig werkt onder normale en onvoorziene omstandigheden. Drie verschillende gesimuleerde case studies lieten zien dat de vermogensstroom betrouwbaar en veilig gestuurd kan worden, met goed dynamisch gedrag, met de *Distributed Voltage Control*-strategie, zelfs wanneer een fout optreedt in een van de aangesloten ac-netwerken.

De mate waarin een multi-terminal dc-netwerk fouten in de aangesloten ac-netwerken kan weerstaan en daarvan kan herstellen zonder uit bedrijf te gaan kan sterk beperkt worden door al te strikte netcodes, zeker wanneer de hoogspanningsomvormers de nominale blindstroom moeten leveren tijdens spanningsdips.

Voor wat betreft dc-fouten is de beste aanpak vooralsnog het multi-terminal dc-netwerk opbouwen in een symmetrische monopolaire configuratie en dc-begrenzende spoelen opnemen, omdat de stroom- en spanningscapaciteit van voldoende snelle dc-vermogensschakelaars nog verbeterd moet worden voordat deze in de praktijk toegepast kunnen worden.

In het algemeen is de transiënte stabiliteit van multi-terminal dc-netwerken een groter probleem dan de kleinsignaalstabiliteit. Kleinsignaal-stabiliteitsanalyses laten zien dat dc-netwerken altijd marginaal stabiele systemen zijn en dat feedback-regeling van de gelijkspanning nodig is om de stabiliteit te verbeteren. Een kleinsignaalmodel van de spanningsomvormers laat zien dat zijn eigenwaarden weinig veranderen door variaties in de parameters van de hardware-onderdelen, zoals het LCL-filter en de uitgangscondensator. Daarnaast is het kleinsignaalmodel van de omvormer gebruikt om de in het laboratorium geteste regeling te optimaliseren.

In de experimentele opstelling hebben drie spanningsomvormers succesvol gefunctioneerd in een parallel-radiaal multiterminal dc-network met een symmetrische monopolaire configuratie. Het dc-netwerk is dynamisch gegroeid: een omvormer is eerst getest als STATCOM, waarbij de ontwikkelde niet-lineaire en kleinsignaal dynamische modellen zijn gevalideerd, omdat de simulatieresultaten een goede overeenkomst vertoonden met de meetresultaten. Vervolgens werden twee omvormers back-to-back aangesloten en uiteindelijk zijn drie omvormers als multi-terminal dc-netwerk aangesloten.

Tenslotte is een real-time digitale simulator gebruikt om het gedrag van een offshore windpark te emuleren. Echte metingen afkomstig van het windpark *Egmond aan Zee* zijn gebruikt om de *Distributed Voltage Control*-strategie te valideren, waarbij de vermogensstroom in het multi-terminal laagspanningsnetwerk succesvol en met grote precisie werd gestuurd, waarbij tegelijkertijd goede dynamische prestaties werden geleverd. Aanbevelingen om de precisie van *Distributed Voltage Control* te verbeteren zijn opgenomen in de conclusies van het proefschrift.

Als toekomstig onderzoek zou het multi-terminal laagspanningssysteem als volgt verder uitgebreid moeten worden: ten eerste dienen meerdere configuraties en topologieën getest te worden, zoals een maasnetwerk; ten tweede door het opnemen van andere componenten, zoals dc-dc-omvormers en/of een stroombron-omvormer, in het netwerk; en ten derde door beveiligingsmaatregelen tegen dc- en ac-fouten experimenteel te testen.

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Part I

Introduction & Literature Review

1

Introduction

Obviously we have unintentionally created a trap for ourselves. We will, so to speak, run out of gas. There is no question about that. There's only a finite amount left in the tank. When will it happen?

Prof. David Goodstein

1.1 General Background and Motivation

Driven by China's development, the year 2008 marked the first time in human history when more people lived in urban areas than in rural regions. In 2012, circa 51% of all Chinese – around 690 million people – were living in cities rather than in the countryside. And world urbanisation is a growing tendency. According to the United Nations (UN), the growth rate of people living in cities will surpass the total world population growth by 2018 [1]. Figure 1.1 shows the world population evolution [2].

Demographic growth will exert increasing pressure on national resources availability, access and infrastructures. It makes it increasingly harder to assure adequate global access to sanitation, water, food and energy supplies. Currently, 2.5 billion people lack access to improved sanitation facilities, 1.3 billion people do not have access to electricity and 780 million people still have no access to safe drinking water [3,4].

However, people without access to these basic services tend, in general, to live in rural areas. Therefore, even though a growing urbanisation process means further challenges towards fighting poverty in slums, guaranteeing social security and jobs, and providing good educational and health systems, it also means better economic opportunities and access to resources, especially energy. According to the International Energy Agency (IEA), the electrification rate is around 92% in urban areas [4].

As the world population increases, urbanisation intensifies and economies grow, it is expected that the global energy consumption will rise as well. In 2010, the world consumed 12.32 billion toe¹, in comparison to 7.10 billion toe² in 1980: an annual increase of 1.85%. In the same period, the world population grew 1.44% annually from 4.5 to 6.9 billion. On the other hand, electricity consumption ex-

- 1.1. General Background and Motivation
- 1.2. Problem Definition
- 1.3. MTdc Network Challenges
- 1.4. Objectives and Research Questions
- 1.5. Outline and Approach

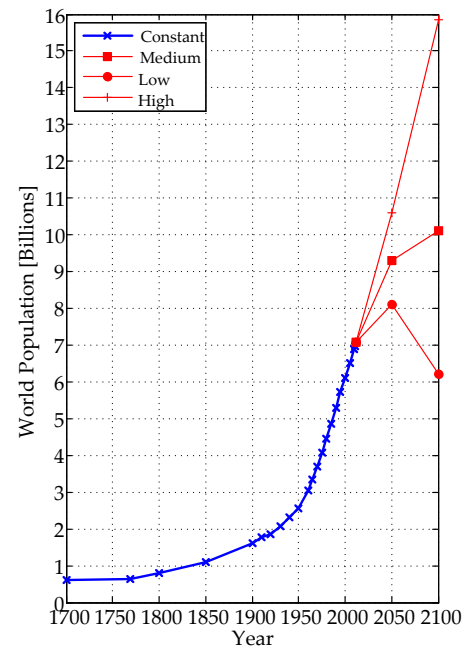


Figure 1.1: World population evolution by year. The future population prediction changes for different fertility rates. The total fertility rate for the higher scenario in 2050 is 2.64 children per woman, only 0.12 higher than the current rate [2].

¹ A tonne of oil equivalent (toe) is defined as 11.63 MWh.

12.32 billion toe \approx 140,000 TWh.

² 81,000 TWh

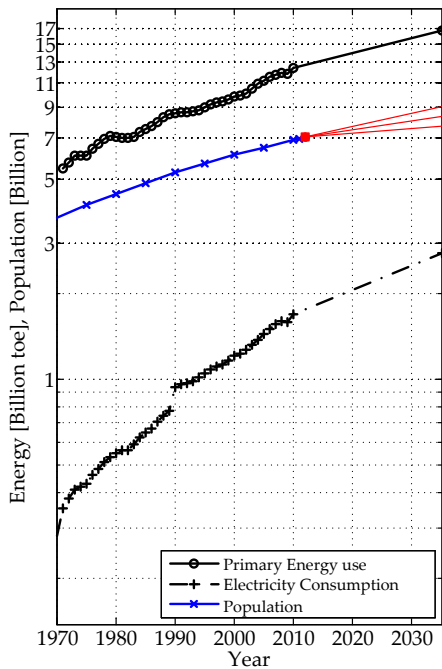


Figure 1.2: Worldwide Primary Energy Use.

³ According to the UN, the European population is expected to shrink by almost 1%, from 739 to 672 million people, in the years from 2011 until 2050.

⁴ Primary energy consumption refers to use of energy before transformation to other end-use fuels.

⁵ 81.1% of the 140,000 TWh of primary energy consumed in 2010 came from fossil fuels: oil (32.4%), coal (27.3%) and natural gas (21.4%). Furthermore, from the 21,431 TWh of electricity generated in 2010, almost 64% was produced by fossil fuels: coal was the main source (40.6%), followed by natural gas (22.2%), hydro (16.0%), nuclear (12.9%), diesel (4.6%) and others (3.7%).

⁶ An important scientific concept for all electrical engineers is the *negawatt*. A negawatt is one energy unit which needed not to be generated due to improved efficiency or energy savings. Whenever possible, "producing" negawatts should be considered much more valuable than adding new watts.

perienced a much stronger annual growth (3.83%), increasing from 6,371 TWh in 1980, to 19,665 TWh in 2010 [4,5].

Energy is a key component to modern societies and the need for energy is increasing worldwide, while electricity supply is becoming ever more important. The worldwide primary energy use and electricity consumption from 1970 until 2035 is displayed in Figure 1.2 [4], together with the population graph from Figure 1.1.

The global energy consumption level, given current policies, is projected to increase by 36% in the following years until 2035. In developing countries, electricity is one of the most important tools for promoting welfare and the worldwide demand for electricity, led primarily by those countries, is projected to steeply increase due to economic and population growth. In fact, the world population and the total primary energy use will grow by similar annual rates – 1.16% and 1.23%, respectively – whilst electricity consumption will increase almost twice as fast, at a 2% rate, due to, amongst other reasons, the urbanisation process.

In developed countries, however, the situation is different. At current fertility rates, the European population will actually shrink³ [2]. Even so, electricity generation in the European Union (EU) is expected to grow, but with an annual rate lower than 1% [4].

Nevertheless, unlimited growth is not the only problem with our current primary energy consumption⁴. Another major problem lies in the main energy source: fossil fuels. Oil, coal and natural gas accounted together for 81.1% of all the world primary energy use in 2010 [4]⁵. At least three main reasons exist for societies to decarbonise electricity production and transportation [6]:

1. It is not possible to count on fossil fuels indefinitely: it is a limited resource [7].
2. Security of energy supply: countries with little fossil-fuel provisions should avoid greatly depending on it.
3. Climate change: burning fossil fuels releases carbon dioxide (CO_2), which increases the greenhouse effect.

As fossil fuels are a mean to obtain energy, the climate change problem is largely an energy problem. One part of the solution is energy efficiency, which concerns both the energy supply and demand side. For instance, if petrol-fueled transportation (demand side) can be made more efficient, it will greatly help save precious fossil fuel reserves for more noble uses, such as fertilisers for food farming. On the demand side, the solution also includes informing end users about the importance of energy conservation and the need to reduce our current energy consumption⁶.

Energy efficiency and conscious energy consumption are important steps to solve our energy problems, but are not the only ones. Specially when it comes to the generation of electricity, another part of the solution will have to come from the energy supply side, in the form of sustainable, renewable energy sources.

As circa two-thirds of all electricity generation is fossil-fuel based, if electricity can be generated, transported and used more efficiently – and rationally – it will forgo investments, save energy and greatly help to preserve fossil fuel reserves. These cornerstones compose the main motivation of the present thesis:

to study an optimal platform to foster the integration of remotely located renewable resources.

1.2 Problem Definition

The best sites for exploitation of renewable resources are usually remotely located from demand centres. Moreover, as renewables have a low power-area ratio, they need vast amounts of land [6], which are more difficult to obtain in urban regions, as these tend to be densely populated.

Examples of remotely located areas with high renewable energy potential include the Brazilian Amazon region and the western part of China (hydro energy), the northern part of Africa (solar energy), and the European seas (offshore wind energy). Hence, the inclusion of remotely located renewable resources will involve bulk electricity transportation over long distances.

In cases where electricity needs to be transported via long overhead lines – as is the case for the hydro power in Brazil and in China, or the solar power in Africa – or in cases where it needs to be transported via underground and submarine cables – as is the case for the offshore wind power in Europe – using direct current high-voltage (HVdc) transmission is more efficient than using high-voltage alternating current (HVac) transmission⁷.

In the European case, in comparison to other places, the need for developing and integrating remotely located renewable resources comes mainly from the EU policies and regulatory schemes towards energy. The EU climate and energy package – known as the 20-20-20⁸ target – places Europe as a world leader in the field of renewable energy. By 2020, the continent could add circa 400 TWh in new electricity generation through different renewable technologies [4].

According to the EU-27 National Renewable Energy Action Plans, wind energy has the potential to supply 41% of all renewable electricity; whereas offshore wind energy will account for 28% of the entire wind energy share [8]. This estimate equals a total of 40 GW of installed offshore capacity throughout Europe by the end of this decade [8,9]. Figure 1.3 shows the electricity generation in the EU, together with the renewable⁹ and wind energy shares [4,8–11].

In the past two decades, wind energy generation in Europe – both onshore and offshore – has experienced a steep growth. By the end of 2011, 94 GW of wind energy – of which 3.8 GW offshore – were installed in Europe (see Figure 1.3) [11]. If the total installed capacity offshore is to reach 44 GW by the end of this decade, it will need to grow – on average – 31.3% annually. This is, however, not unprecedented. Between 1995 and 2005, total wind energy installed capacity

⁷ The reason why it is sometimes preferable to use HVdc technology instead of HVac technology is explained in more detail in Chapter 3.

⁸ 20% greenhouse gas emissions reduction from 1990 levels; 20% energy consumption from renewable sources; 20% energy efficiency improvement.

⁹ The considered technologies are: hydro; biomass and waste; geothermal; marine and wave; photovoltaic and concentrated solar; and wind.

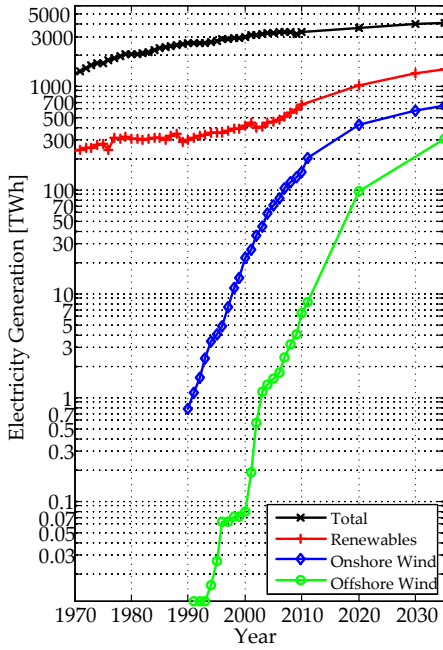


Figure 1.3: Electricity generation in the European Union.

¹⁰ see Chapter 3 for more information.

¹¹ The accuracy of the prediction will actually depend on whether MTdc networks will be available or not. Similar predictions already existed a decade ago but, have not been verified; and conversion from ac to dc increased only by 5%, from 25% to 30% [14].

in Europe rose from 2.5 to 40.5 GW, a 32.1% annual average growth [9]. To meet the EU-27 action plan targets, the offshore wind industry just has to grow at similar rates.

For the onshore development to be replicated offshore, Europe will need a common political framework to deal with the different regulations and policy aspects. Such a political framework in the EU is likely to come from the North Seas Countries Offshore Grid Initiative (NSCOGI). Additionally, besides large investments in research and development, the construction of an offshore transnational grid is regarded as one of the key elements to accomplish the offshore wind energy targets [12], which leads to the problem definition:

what is the best way to integrate offshore wind farms and to deliver large amounts of power ashore most efficiently?

As new offshore wind farms tend to be located further away from shore and to have a higher installed capacity [11], the North Sea offshore transnational grid is anticipated to be built as a high-voltage multi-terminal dc (MTdc) network. Underground and submarine HVac transmission cables suffer greatly from losses due to charging currents, thus, it is unlikely that offshore grids will be built with alternating current (ac) technology¹⁰ [12]. On the other hand, multi-terminal dc networks, characterised by having three or more terminals somehow connected through direct current (dc) cables, are more efficient for underground and submarine use.

Additionally, almost 30% of all the electricity presently generated is converted from ac to dc before it is actually used. In the next two decades, conversion from ac to dc is predicted to rapidly increase to a staggering 80% [13]¹¹. Multi-terminal dc networks can help pave the way for further penetration of power electronic converters serving dc loads in low (LVdc), medium (MVdc) and high-voltage dc applications. These dc networks can be applied in many fields of electrical engineering: from microgrids and smart grids, to electronic power distribution systems [15] and supergrids dedicated to the integration of remote renewable sources on a continent level [16,17].

1.3 MTdc Network Challenges

Before MTdc networks can be developed, various challenges need to be addressed and solved. The five challenges analysed in this thesis are identified in this section. They arise due to the fundamental differences in the operation and control of alternating current and direct current networks.

The first challenge deals with the requirements for the development of MTdc systems. The last four cover MTdc systems behaviour under steady-state, transient and contingency scenarios.

System Integration

The present infrastructure to generate, transmit and distribute electricity using ac technology is the result of engineering evolution and

improvements for more than a century¹². Likewise, multi-terminal dc networks will have to organically grow with time; from an inherently simple initial phase to a desired later form, a hopefully much more complex meshed topology (see Figure 1.4) [12]. However, the development will have to happen in a much shorter time.

The North Seas Countries Offshore Grid Initiative, with its intention of interconnecting circa 40 GW of offshore wind power between several countries in Northwest Europe up to 2030, is a very ambitious plan [11,12]. For projects of such dimension and complexity, it is extremely important to choose the most suitable system architecture from the start [21]. After the system architecture is defined, the next step is to distinguish clearly which are the objectives and primary functions of each system modules and submodules, and what are the possible interactions between them. The task of establishing the functionalities inside the system and assuring optimal performance is accomplished by system integration [22].

Power Flow Control

The ability to control the power flow will be one of the most important factors for the successful development of MTdc networks. The main purpose of a transmission system is to reliably, safely and cost effectively bring electricity from generation to a point where it can be distributed for practical use. Yet, controlling exactly how power flows in a transmission system – be it ac or dc – is not an easy task. Electricity, as other substances such as water and light, conforms to the principle of least action [23]. According to Feynman [24]:

“if currents are made to go through [...] obeying Ohm’s law, the currents distribute themselves [...] so that the rate at which heat is generated is as little as possible.”

Hence, as known, electric power flow is inversely proportional to the impedances in the current path.

In ac networks, FACTS¹³ devices are used to help control, to some extent, the power flow. They work by varying a transmission line characteristic impedance or its voltage phase angle [25]. In dc networks, however, voltages do not possess a phase angle; and the transmission line impedances are purely resistive¹⁴. Therefore, the only variables left for power flow control in dc networks are the voltages and currents amplitudes. In point-to-point HVdc transmission systems, the power flow control is typically arranged so one terminal controls the dc-link voltage, while the other terminal controls the current through the dc line [26]. This control philosophy – of having only one converter controlling the direct voltage – can be extended to small MTdc networks. Still, for improved performance, reliability and safety reasons, future large MTdc networks will require a power flow control strategy capable of sharing the direct voltage control amongst more than one network node.

¹² The first ac transmission line was built in Italy in 1886, from the Cerchi thermoelectric power plant, at l’Aventino, to Rome. It used the Ganz system to transmit 300 HP at 2 kV for circa 30 km [18,19].



Figure 1.4: Future vision of the North Sea Transnational Grid by the OMA [20].

It will definitively take time – probably decades – political, economical and engineering efforts, before the offshore grid will start to resemble the network shown above.

¹³ Flexible AC Transmission Systems.

¹⁴ When in steady state. During transients the transmission line series inductance and shunt capacitance also play a role.

¹⁵ For ac networks, dynamic studies have to be performed from 5 up to 30 s [28]; whereas in dc networks, fast transient phenomena can happen within less than 100 ms, i.e. less than 5 cycles for ac grids operating at 50 Hz [29].

¹⁶ The inertia constant for large synchronous machines, $H = J\omega^2/2S_n$, is usually in the seconds range, from 1 up to 10 s [28]. For comparison, the inertia constant of a 1 GW voltage-source HVdc converter operating at a dc-side voltage of ± 320 kV, with an output capacitance of $100 \mu\text{F}$, is $\tau = C_{dc}V_{dc}^2/2S_n \approx 20$ ms, 50 to 500 times less than an synchronous machine.

Dynamic Behaviour

The behaviour of ac and dc networks over time can be significantly different. In an ac network, the main component which provides active and reactive power is the synchronous machine. Hence, understanding and comprehensively modelling the machine dynamics is of key importance to assess the dynamic behaviour of ac power systems [27]¹⁵.

Similarly, the main component which exchanges power in dc networks is the power electronic converter. In comparison to synchronous machines, power electronic converters have much faster response, due to additional control capabilities, but also due to a much lower inertia¹⁶. Therefore, modelling the power electronic converter dynamics is a key aspect for understanding the behaviour of multi-terminal dc networks.

However, due to their switching behaviour, the dynamic equations describing the converter operation are discontinuous and complex to solve. To simplify the power electronic converter complexity, averaged dynamic models are employed. The advantage of using averaged models is that they simplify the converter analysis while still allowing enough details to understand its dynamics and develop control strategies [30]. Since it will be difficult to build prototypes of the North Sea Transnational Grid (NSTG), dynamic models of future offshore MTdc networks are needed for assessment of the overall system behaviour, during sound and fault conditions, to study the interactions between the offshore wind farms, the power electronic converters and other dc equipment, but also for designing control strategies to optimise the system performance.

Stability

The stability of a system is defined as its ability to reach a new equilibrium state – or operating point – after being subject to a disturbance. In ac networks, power system stability is usually divided in three categories: rotor-angle, voltage and frequency stability [31]. Rotor-angle stability is further divided in small-disturbance angle stability and transient stability, and both are intimately related to the dynamic behaviour of synchronous generators. Voltage stability relates to the ability of the power system to keep acceptable voltage levels in all network nodes during steady state, and after disturbances. It is associated with the system capability to supply reactive power for a given active power demand, hence, voltage instability usually happens when reactive-power support is insufficient in highly loaded areas [27]. The last category of ac power system stability is frequency stability, i.e. the system capacity to maintain generation and load in equilibrium, and to regain equilibrium after a severe disturbance while losing a minimum amount of loads.

In dc networks, currents and voltages have no synchronous frequency component and, hence, there is also no reactive power flow. Additionally, active power flow depends on differences between volt-

ages rather than load angles. Therefore, the stability of dc networks, which depends only on the system voltages, has to be analysed in a different way than for ac power systems. More importantly, it has to include the dc network passive components, but also the power electronic converters and their feedback controllers [32].

Fault Behaviour

Two main types of fault scenarios can take place in MTdc networks. Firstly, faults can occur on the power electronic converters ac side. These type of faults can be single or multi-phase; but, generally speaking, they will represent a loss of generation or load to the dc network. Nonetheless, for the successful development of MTdc networks, it is imperative that a contingency in one ac power system is not propagated to another, isolated ac system, through the dc grid. Secondly, faults can happen on the power electronic converters dc side. These type of faults will be much more challenging to handle than ac faults [33]. During a dc fault all interconnected ac systems will contribute to the fault current and, because of the dc cables low impedances, the voltages in the MTdc will be substantially reduced, nearly stopping the power flow; thus, the development of protection in dc networks – specially for HVdc networks – is a critical issue [34].

1.4 Objectives and Research Questions

If the five key issues regarding MTdc networks – system integration, power flow control, dynamic, stability and fault behaviours – can be studied, better understood and improved, it is very likely that the first small MTdc networks, with 4 to 6 nodes, will be developed within the next decade. Keeping these five key issues in mind, the main thesis objective is:

to study to what extent multi-terminal dc networks can provide an optimal platform for the integration of offshore wind energy in the North Sea.

The research questions in this thesis are connected to the five problems presented in the previous section. Each research question corresponds to a thesis chapter and has its own set of objectives, which are given next¹⁷.

Chapter 2: What is the best HVdc technology and configuration for a MTdc network in the North Sea?

- Perform a review of HVdc transmission technology, and configurations, to identify the best option for the development of a MTdc network in the North Sea;
- Analyse what has prevented the development of MTdc networks in the past;
- Compare different topologies for construction of MTdc networks.

¹⁷ Even though the main focus is on the integration aspects of offshore wind power using a HVdc network, the research questions motivating the present thesis have to be answered for MTdc networks of any purpose and voltage level.

Chapter 3: How does the power flow in MTdc networks?

- Establish when the transmission system of an offshore wind farm should be done in direct current;
- Study the role and impacts of system architecture on the development of MTdc networks for offshore wind applications;
- Develop a load flow algorithm to analyse the power flow in MTdc networks with more than one slack node¹⁸;

¹⁸ A slack node is considered as a node controlling the MTdc network voltage.

Chapter 4: How to model the combined dynamic behaviour of a MTdc network?

- Create non-linear dynamic models of the most important modules inside MTdc networks: i.e. the offshore wind farms, the HVdc converters, the dc cables and control systems;
- Establish how the models are connected to each other based on their signal flow;
- Analyse the control structure of a HVdc converter station.

Chapter 5: What are the shortcomings of the main methods for controlling the direct voltage in MTdc networks?

- Compare the most common control strategies for MTdc networks;

Chapter 6: What is needed to control the power flow in MTdc networks?

- Evaluate how to optimise the power flow in MTdc networks.
- Develop a novel direct voltage control strategy capable of reliably and securely operating a MTdc network during steady-state and fault scenarios.

Chapter 7: What is needed for a MTdc network to be able to withstand and recover from faults in the connected ac systems, or in the dc grid itself, without halting its operation?

- Use the develop models to study the behaviour of MTdc networks during ac and dc contingencies;
- Investigate the influence of grid code requirements on MTdc networks during ac contingencies;
- Analyse the impact of the HVdc transmission system configuration on dc contingency management;

Chapter 8: What are the main variables affecting the small-signal stability of MTdc networks?

- Develop linear small-signal models of the MTdc network components for stability analysis;
- Analyse the system eigenvalues and their sensibility to parametric variations.

Chapter 9: To what extent is it possible to reproduce the behaviour of a high-voltage MTdc network through a low-voltage one?

- Test and validate the developed models on real power electronic converters;
- Form a LVdc network by connecting more than two power electronic converter on their dc sides;
- Test the novel control strategy on the developed LVdc laboratory setup.

From all the research questions and objectives listed above, the main contributions of this thesis are:

1. Concepts for classification and system integration studies of MTdc networks;
2. Development of tools for MTdc networks analysis: multiple slack load flow algorithm, dynamic models, a novel MTdc control strategy and stability analysis concept.
3. Construction of a low-voltage multi-terminal dc (LV-MTdc) network system in the laboratory with a power hardware in the loop simulator, and comparison of the obtained measurements with the simulation results from the generated models.

1.5 Outline and Approach

This section presents the thesis outline and the approach used in each chapter (see Figure 1.5). The thesis is divided in five main parts, viz.: Introduction & Literature Review, Steady-state Analysis; Dynamic Analysis; Stability Analysis; and Experimental Work & Conclusions¹⁹.

Part I. Introduction & Literature Review

Chapter 1 and Chapter 2 are included in the thesis first part. Chapter 2 starts with the historical development of high-voltage direct current transmission systems. The chapter then presents a thorough literature review on the state-of-the-art HVdc technologies and possible HVdc configurations to form MTdc networks. It investigates why there are currently only three such dc networks in the world. Finally, it looks into possible MTdc network topologies and suggests a way to classify MTdc networks according to its topology and technology employed.

Part II. Steady-State Analysis

In this part, steady-state tools are used to provide the motivations for the use of dc technology, and to access how power flows inside MTdc networks.

¹⁹ The thesis layout presented in Figure 1.5 shows the five main parts and how the chapters are place within them. Additionally, on the upper left corner of each part, it shows which challenge from section 1.3 is tackled in that part. Finally, it displays the interaction between the thesis chapters.

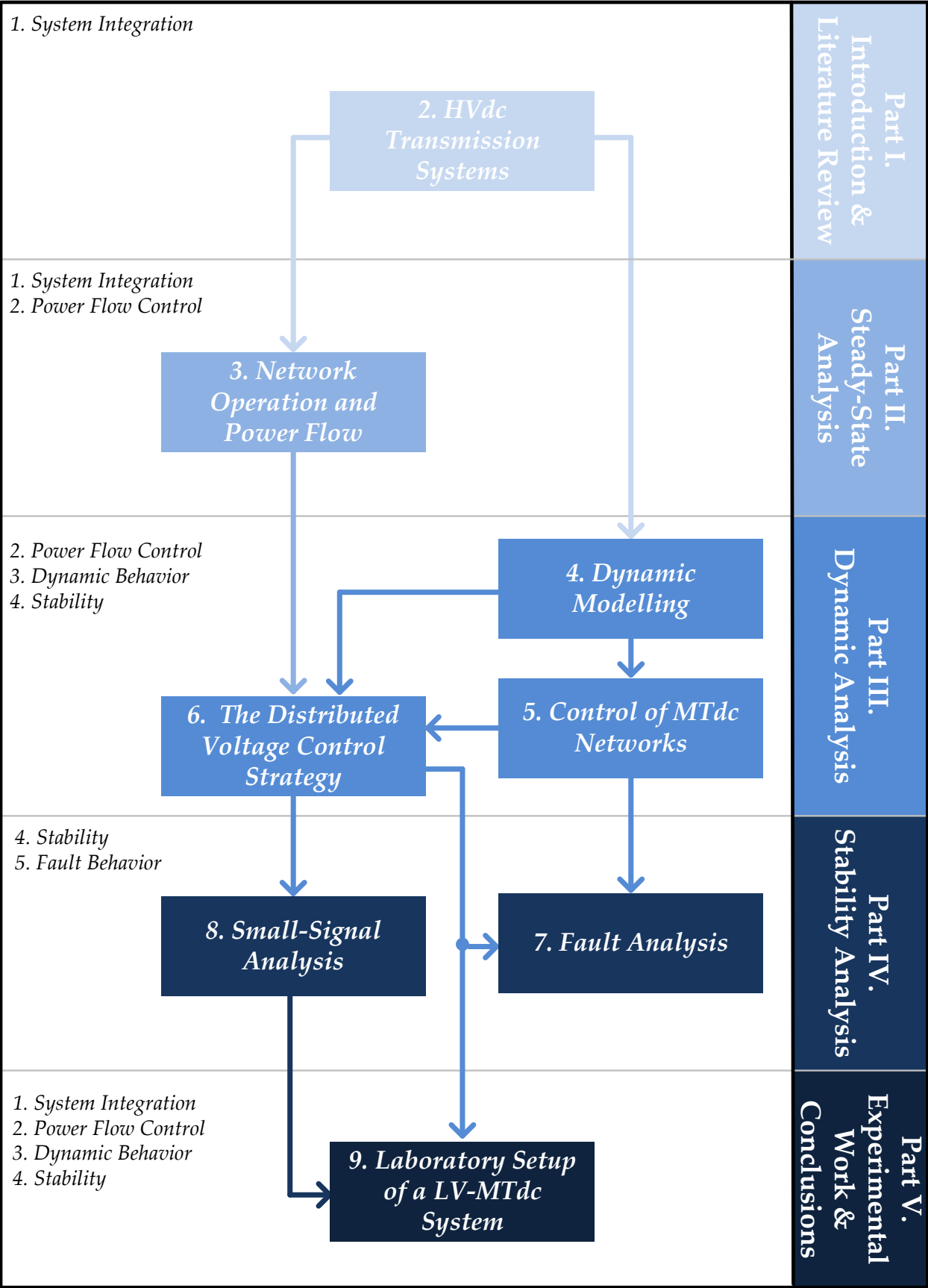


Figure 1.5: Thesis outline.

The reasons why it is sometimes both technically and economically more advantageous to use dc technology instead of ac technology are presented in Chapter 3. It provides an approach to determine when to select dc transmission systems for the integration of offshore wind farms. With regard to MTdc networks, Chapter 3 stresses the importance of selecting the right system integration architecture starting from early development stages. It shows that for complex systems such as the NSTG, one potential solution is to adopt a modular approach, and it highlights the importance of design hierarch and the need for standardisation, or offshore grid codes.

Finally, Chapter 3 presents a dc load flow algorithm, with multiple slack nodes, as a tool to first understand how power flows inside multi-terminal dc networks, and it finishes with a first discussion on system security analysis.

Part III. Dynamic Analysis

The third part of the thesis deals with the dynamic analysis of MTdc networks, and is divided in three chapters: one on the dynamic models, and two on the control of MTdc networks.

Chapter 4, gives the dynamic models of the most important components in the NSTG network: i.e. the voltage-source converter (VSC), the dc network and the offshore wind farm models. It starts by giving an overview showing how the components interact inside of the complete model. The approach in Chapter 4 is to derive the equations driving each of the NSTG components, and to build modular dynamic models which represent the complete system behaviour over time. The developed models are kept as simple as possible to be as fast as possible. However, they are kept sophisticated enough to provide significant results about the system operation.

In Chapter 5, the most common literature methods for the control of MTdc networks are presented and compared. A case study, using the dynamic models developed in Chapter 4, is performed on a four-terminal dc network to evaluate and compare the different control methods according to a given set of criteria²⁰.

Finally, based on the findings in Chapter 3, a new method of controlling MTdc networks composed of voltage-source converters is presented in Chapter 6. The method is called *Distributed Voltage Control* (DVC) and it is shown, via three case studies, to significantly improve power flow controllability and stability in MTdc networks.

Part IV. Stability Analysis

In Part IV, the stability of MTdc networks is assessed first via a transient stability analysis, which determines the system capacity of withstanding ac and dc contingencies. The stability of MTdc networks is latter assessed via a small-signal stability analysis, which checks the system eigenvalues for parametric variations in the components and control gains of a voltage-source converter.

The transient stability analysis is conducted in Chapter 7. It inves-

²⁰ The methods compared are: droop control, ratio control, priority control and voltage-margin method control. They are compared with regard to dynamic performance, flexibility, expendability and telecommunication needs.

tigates the impact of grid code requirements on the fault behaviour of MTdc networks during ac contingencies. With regard to dc contingencies, Chapter 7 provides a methodology to study these type of faults and analyses the influence of HVdc system configuration on dc contingencies management. The main analysis tools used in Chapter 7 are the non-linear dynamic models, developed in Chapter 4, and the MTdc network controllers, developed in Chapters 5 and Chapter 6.

The small-signal stability analysis is conducted in Chapter 8. The analysis is performed by derivation of linear models for the MTdc network and for the voltage-source converters, including their complete control structure develop in Chapter 4. Using an optimisation algorithm, the converters control gains are optimised. After optimisation, a comparison between the results from the small-signal model and experimental results is carried out to validate the developed models. Finally, a study of the system robustness against parametrical variations is performed by analysing the location of its eigenvalues in a root locus.

Part V. Experimental Work & Conclusions

The fifth thesis part contains the results from the laboratory experiments involving the low-voltage MTdc network setup, and the final chapter with the thesis conclusions and recommendations for future research.

Chapter 9 demonstrates, in a laboratory environment, the operation and control of a LV-MTdc network using voltage-source converters. The system integration concepts of Chapter 2, the power flow control and dynamic modelling from Chapter 3 to Chapter 6, and the small-signal stability analysis developed in Chapter 8 are all employed for the development of the experimental setup. The chapter main purpose is to validate the developed models for the VSC and MTdc network, and to demonstrate the ability of the distributed voltage control strategy in controlling the power flow in the LV-MTdc grid.

Finally, Chapter 10 provides general conclusions on the performed work, and gives recommendations for future research.

2

HVdc Transmission Systems

Any engineer who wanders through one of the large Thury stations and then calls to mind the usual long concrete catacombs bristling with high-tension insulators and filled with dozens of oil switches, scores of disconnecting switches, webbed with hundreds of feet of high-tension leads and spatted with automatic cut-outs, will stop and think a bit before he complacently sniffs at high-tension direct-current transmission.

A. Still, Overhead Electric Power Transmission: Principles and Calculations, 1913.

The introduction chapter presented the challenges facing the development of high-voltage multi-terminal dc networks. At the core of these multi-terminal dc networks are the high-voltage direct current transmission systems, but different technology options and configuration possibilities exist. The aim of this chapter is to determine what is the best HVdc technology option and configuration for the development of multi-terminal dc networks in the North Sea. The Chapter starts by briefly reviewing the first steps taken during the historical developments of HVdc systems in the nineteenth century. After that, it introduces modern high-voltage direct current transmission technologies and their possible configurations. Then, it discusses the evolution of the first HVdc transmission systems into multi-terminal ones and gives reasons why their development did not continue. Finally, the chapter discusses the topologies options for MTdc transmission networks and suggests, based on the literature review, the best HVdc technology and configuration for the development of the North Sea Transnational Grid.

- 2.1. Early HVdc Transmission Systems
- 2.2. HVdc Classic
- 2.3. VSC-HVdc
- 2.4. HVdc Transmission System Configurations
- 2.5. From Point-to-Point to Multi-Terminal DC Networks
- 2.6. MTdc Network Topologies
- 2.7. Conclusion

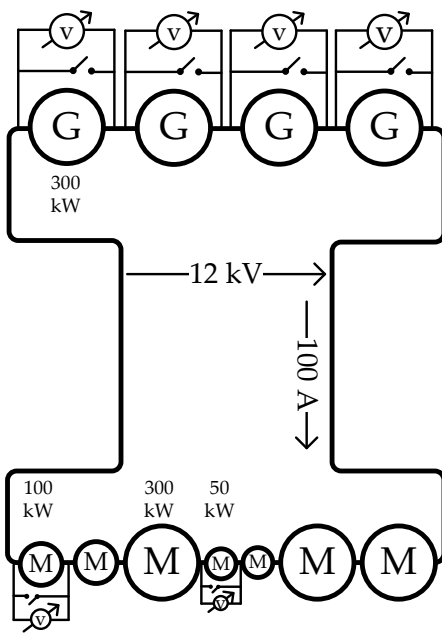


Figure 2.1: Diagram of a small 1.2 MW Thury system [36].

The Thury system shown contains on the generation side 4 dc generators rated at 300 kW and 3 kV each. At the receiving end of the line there are two 100 kW dc motors rated at 1 kV, two 50 kW dc motors rated at 500 V, and three 300 kW dc motors rated at 3 kV.

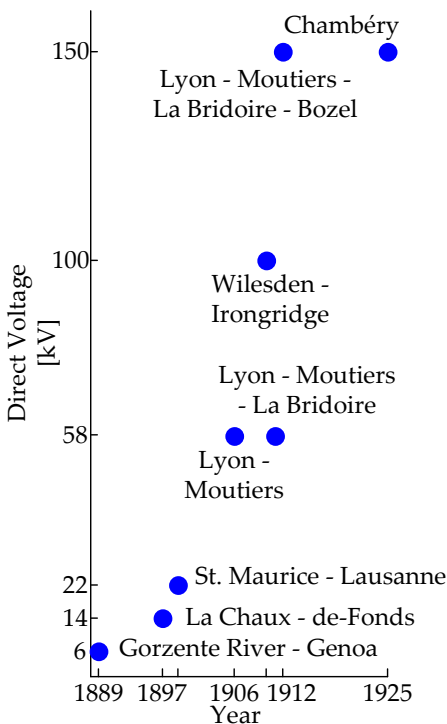


Figure 2.2: Evolution of the direct voltage in the Thury systems installed between 1889 and 1925.

2.1 Early HVdc Transmission Systems

Despite the success of high-voltage ac transmission systems, the efforts for the development of a practical high-voltage dc transmission continued. The first attempted to realise a HVdc transmission system was done in Genoa, in 1889, using a Thury System. The Isoverde hydroelectric power plant, the first of its kind in Italy, transmitted dc electricity at 6 kV for 27 km, from the Gorzente river to Genoa [35].

The Thury System

The system designed by Swiss engineer René Thury, was composed of dc generators (Thury dynamos) and motors connected in series. The current in the circuit was constant, whereas the voltage was varied to meet the power demand. Figure 2.1 shows a typical diagram of a small Thury system for transmission purposes [36].

Each dc generator and motor had a series switch used to short-circuit its terminal when they were not being used. To enter into operation, a generator was first brought to the nominal line current and only afterwards its short-circuit switch was opened. Motors were included in the circuit at a position of null torque and then accelerated to the speed required by the load. Insulation in the Thury system was difficult; each generator and motor were mounted on insulators (asphalt over asphalt concrete) to isolate it from ground potential.

Nevertheless, by the 1910s, after HVac transmission systems were already consolidated, there were at least 15 Thury systems installed in Europe, between France, Hungary, Italy, Russia, Spain and Switzerland [37]. Unfortunately, little information is available on these systems. According to [36], the average transmission length of the installed Thury systems was circa 80 km at an average 14.5 kV transmission voltage. Prof. Alfred Still predicted in 1913 that Thury systems up to 48 MW could have been built:

"Assuming a current of 400 amp., which would probably be transmitted by two or more conductors connected in parallel, the output of each machine would be 2000 kw. and [...] With twelve pairs of generators, the pressure between wires would be 120,000 volts and the maximum total output 48,000 kw. There would be very little new or experimental engineering work in connection with such a scheme."

Although power ratings of 50 MW were never achieved using Thury systems, bipolar voltages of up to 150 kV were successfully achieved. Figure 2.2 shows the voltage rating evolution of Thury systems between 1889 and 1925 [37]. The most interesting Thury system was the one between Lyon and Moutiers, in France.

According to [37], it started as a 4.3 MW HVdc transmission system between Lyon and a hydroelectric power plant in Moutier, France. The system current was 75 A and the direct voltage was regulated up to 57.6 kV, distributed between 16 generators at Moutier. Then, in 1911, the system was upgraded by the addition of a second hydro power plant at La Broidoire. The second plant, rated at 6 MW, was

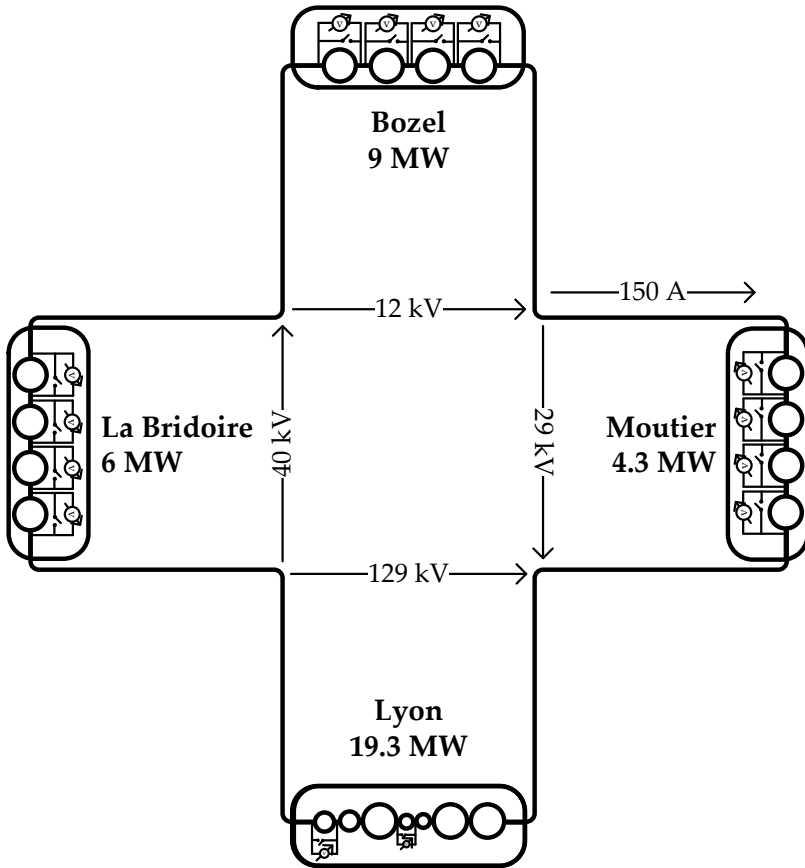


Figure 2.3: First high-voltage multi-terminal dc network.

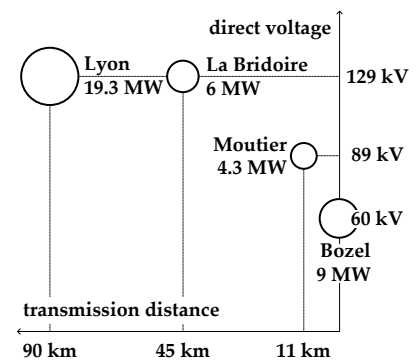


Figure 2.4: Voltage profile of the Moutier-Lyon Thury system and distance between the four terminals.

added in series to the original HVdc line and the system current was doubled to 150 A. Finally, a third hydroelectric plant, rated at 9 MW, was added in Bozel.

Until 1937, when it was dismantled, the Moutier-Lyon-Bridoire-Bozel Thury system operated with four terminals and can be assumed as the first high-voltage multi-terminal dc (HV-MTdc) transmission network in the world. The layout of the multi-terminal dc network is shown in Figure 2.3, whereas Figure 2.4 shows the voltage profile along the transmission system.

The Mercury-arc Valve HVdc System

In a Thury system, conversion from dc to ac, and ac to dc, was only possible using a motor-generator set¹. Since electricity had to be first converted into mechanical power and to be then converted back to electricity, the conversion process was not very efficient.

The pursuit of an electrical component capable of converting ac into dc started as early as 1901, when American electrical engineer Peter Cooper Hewitt invented the mercury-arc valve [38]. In its initial form, the mercury-arc valve behaved as a diode, thus only ac to dc conversion, i.e. rectification, was possible. As most electrical applications at the time were in ac, if electricity was to be transmitted in dc, it was also necessary to perform inversion, converting dc to ac

¹ Nowadays, converting electricity from dc to ac is commonly known as *inversion*, whereas converting electricity from ac to dc is known as *rectification*.

² Once a mercury-arc valve started conducting electricity, the only way to stop conduction was to drive the current through the valve to zero via an external circuit and make sure the cathode was at a higher potential than the anode. Because of this characteristic, systems using mercury-arc valves came to be known as line-commutated converters.

before electricity could be used.

Inversion using mercury-arc valves only became a possibility in 1930, when the grid electrode was introduced [37]. The grid electrode allowed the valve conduction to be delayed past the point where the anode became more positive than the valve cathode².

Two years after the introduction of the grid electrode in 1930, the first HVdc transmission system using mercury-arc valves was built in the USA. It connected a hydroelectric power plant in Mechanicville to Schenectady, in New York, using a 37 km transmission line at 12 kV. The line capacity was 5 MW, and an interesting fact was that the original ac frequency at Mechanicville was 40 Hz, whereas the ac output produced at Schenectady was chosen to be 60 Hz. Therefore, the HVdc transmission system not only carried the electric power, but it also performed ac frequency conversion [37].

However, early mercury-arc valves suffered from backfire (or arc-back), which means they would undesirably allow electricity to be conducted in the opposite direction when high blocking voltages were involved. The backfire issue was solved in 1939, by Swedish engineer Uno Lamm, who introduced a system of grading electrodes which helped increase the reverse peak voltages a mercury-arc valve could manage [37,39]. After this technological breakthrough, between 1939 and 1951, at least 7 experimental HVdc transmission systems using mercury-arc valves were built in Switzerland, Germany, Sweden and Russia.

A project built in Germany, in 1945, was the largest of the experimental systems. The Elbe HVdc transmission system was supposed to connect a power plant at Vockerode to Berlin and consisted of a 110 km dc line at 400 kV with 60 MW installed capacity. The Elbe project, which never went into service, was dismantled and later used in building the Moscow-Kashira HVdc project³ [26].

The first commercial HVdc transmission system was the Gotland 1 project (see Figure 2.5), built in Sweden by the local electric company ASEA [40]. The system entered into operation in 1954 connecting the Swedish mainland, at Västervik, to Ygne in the island of Gotland. High-voltage dc transmission was preferred over HVac transmission due to the long – 98 km – submarine distance involved. The first commercial HVdc system was capable of transmitting 20 MW and was operated at a direct voltage of 100 kV [26].

Figure 2.6 shows the evolution of HVdc transmission systems using mercury-arc valves from 1932 until 1975 [41]. After the successful commercial operation of the Gotland 1 project, the interest in HVdc transmission systems grew, and at least 10 other projects using mercury-arc valves were constructed.

After the war of the currents ended, it took circa 60 years for HVdc transmission systems to make a comeback. By the end of the 1970s, transmission voltages higher than 400 kV, and installed capacities over 1000 MW, were already possible, as demonstrated in the Pacific Intertie (1440 MW, 500 kV) and Nelson River (1620 MW, 450 kV) projects shown in Figure 2.6 [26,37,41–43].

³ The Russian HVdc project, built in 1951, had half of the Elbe project capacity, i.e. 30 MW, and it used a 110 km transmission line, operated at 200 kV.

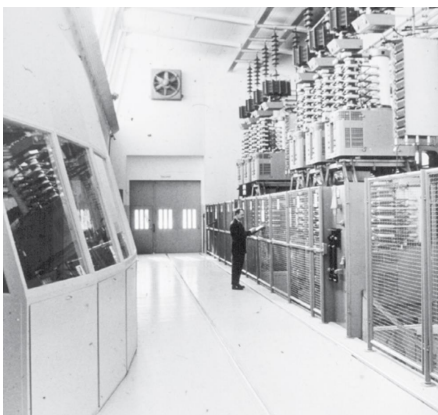


Figure 2.5: Photography from the Gotland 1 mercury-arc valve hall during the 1950s [40].

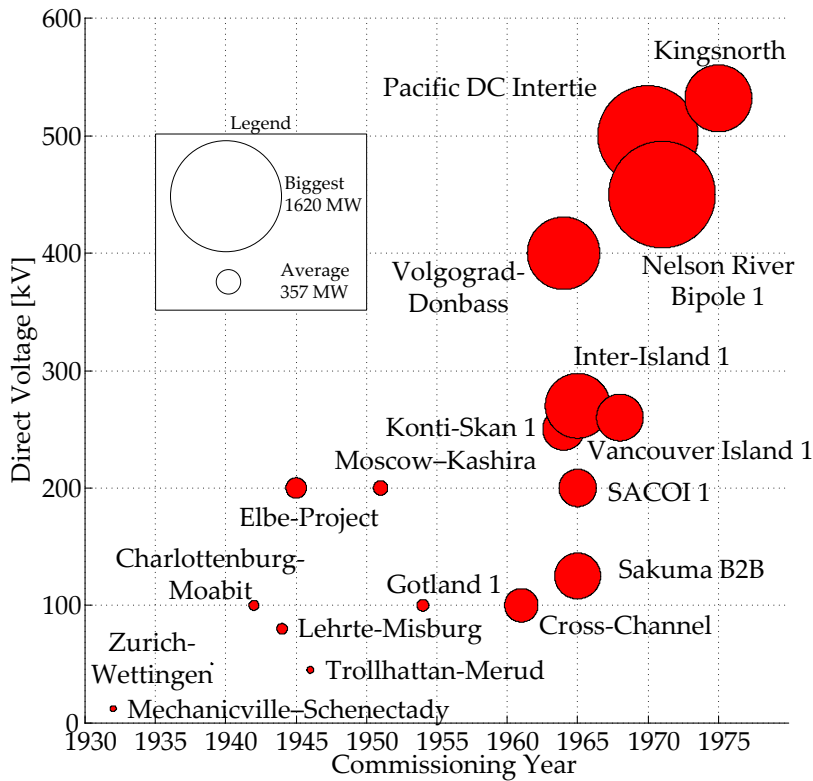


Figure 2.6: Evolution of HVdc systems using mercury-arc valves.

In the graphic shown, the circle's area reflect the installed capacity of the different HVdc transmission systems.

Up to 1945, most of the experimental lines had been built in Germany, but the Second World War prevented their continuation. The Swedish built an experimental line from Trollhattan to Mellerud in 1944 and, only 10 years later, power was being delivered to the island of Gotland via a HVdc transmission system, which was considered cheaper than building new power plants locally. The second commercial HVdc project, built in 1961, the Cross-Channel HVdc link (160 MW, 100 kV), also used submarine cables to connect England and France. Around 1965, six new HVdc lines were built in six different countries. In the 1970s, the biggest HVdc projects using mercury-arc valves were built. From 1954 to 1975, the average installed capacity was 572 MW and the average transmission voltage was circa 300 kV. By the end the 1970s, the mercury-arc valve technology was replaced by solid-state thyristor valves.

2.2 HVdc Classic

During the decades following the development of the first commercial HVdc project in 1954, a great increase in research and development brought to HVdc the use of high-power solid-state switching devices. The thyristor – or silicon-controlled rectifier (SCR) – made it possible to achieve transmission voltages which were not possible using mercury-arc valves.

The world first commercial solid-state HVdc system was commissioned by General Electric in 1972, as part of a contract for the Eel River link in Canada (contracted in 1969) providing an asynchronous connection between Hydro-Québec and New Brunswick Power [26,41]. The converter station had a back-to-back configuration and its power rating was 320 MW at a voltage of 160 kV.

By the end of the 1970s, thyristor valves had already substituted mercury-arc valves for new HVdc applications [37]⁴. Today, thyristors are still the semiconductor device with the lowest conduction losses and highest blocking voltage capability. A modern 6-inch thyristor (see Figure 2.7) can carry up to 4 kA, which avoids the need for paralleling devices, and can block up to 8.5 kV [44].

Figure 2.8 shows the evolution in the thyristor technology for HVdc applications – commonly referred to as HVdc Classic technology – and the accumulated HVdc projects installed capacity worldwide, including projects yet to be commissioned until 2015 [41,45]. After improvements in thyristor valves, larger powers could be trans-



Figure 2.7: Modern HVdc 6-inch thyristor and its wafer [44].

⁴ In the words of Kimbark (1971):
"At present these [thyristor valves, ed.] are not capable of handling the highest voltages and power required for HV dc transmission. Their ratings have increase, however, with surprising rapidity, and it seems certain that such valves will soon replace mercury-arc valves in HV dc use."

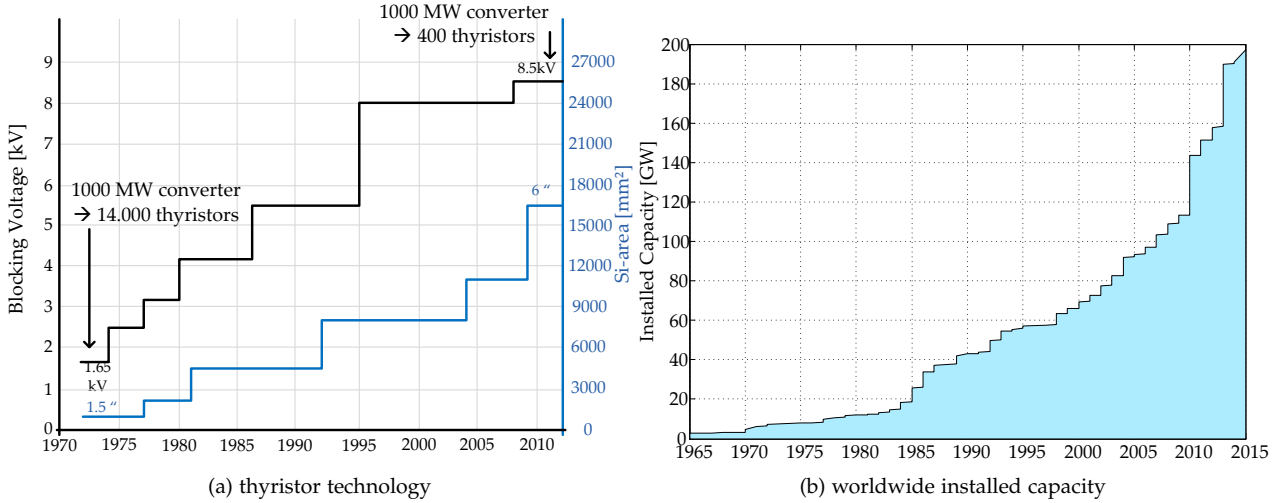


Figure 2.8: Evolution of HVdc Classic Systems [41,45].

mitted via HVdc transmission systems through longer distances. The thyristor technology is nowadays very mature and there are over 140 HVdc Classic transmission systems installed worldwide [41].

HVdc Classic Station

In a HVdc Classic station, a large number of thyristors need to be connected together to build a converter valve module capable of withstanding the voltage levels required for HVdc transmission [26, 45]. Figure 2.9 shows a typical valve arrangement in a 12-pulse HVdc Classic system, whereas Figure 2.10 shows the valves physical arrangement, which hangs from the HVdc Classic station ceiling to improve seismic reliability.

Modern HVdc valves, such as the one shown below in Figure 2.11, make use of light-triggered thyristors, which can be triggered via a fiber optic cable permitting elimination of auxiliary power circuits, gate pulse amplifiers, gate drive units and pulse transformers at thyristor potential. With no need of electronics at a high potential and with fewer components the resulting valve module has increased reliability [45].

For HVdc projects with high power ratings and voltage levels, multiple 12-pulse bridges can be used to help further reducing the harmonic components of the ac-side current and the dc output voltage. Using multiple bridge converters, e.g. the 24-pulse or 48-pulse configuration, the harmonic performance of the HVdc transmission system is improved, reducing filter costs [46].

The fact that multiple bridge converters require less filtering is the main reason why almost all modern HVdc systems make use of such configurations. However, transformer connections to provide the necessary phase shift become more complex and the converters are more difficult to justify economically.

The HVdc converters represent the heart of the transmission systems as they are responsible for the actual ac-dc and dc-ac conver-

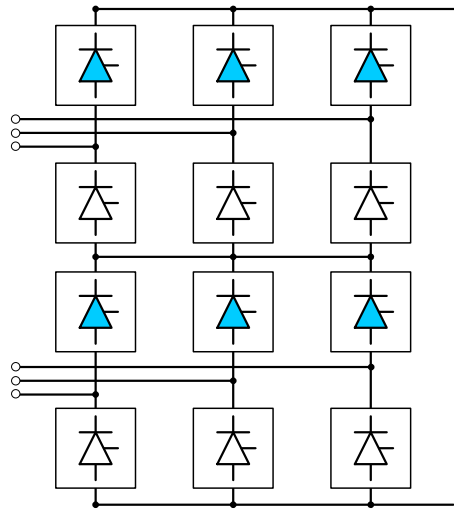


Figure 2.9: 12-pulse HVdc converter topology.

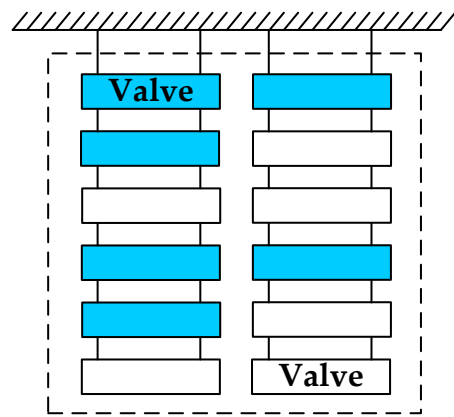


Figure 2.10: Valves physical arrangement.

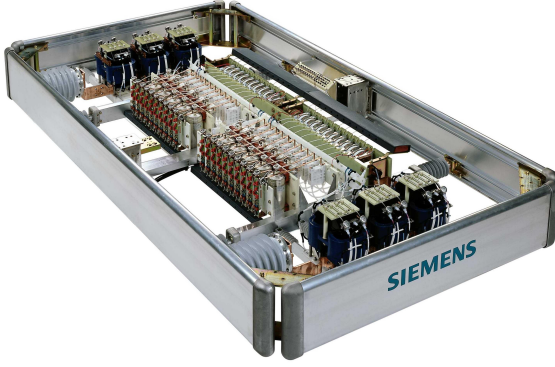


Figure 2.11: A typical modern light-triggered thyristor HVdc valve module [47].

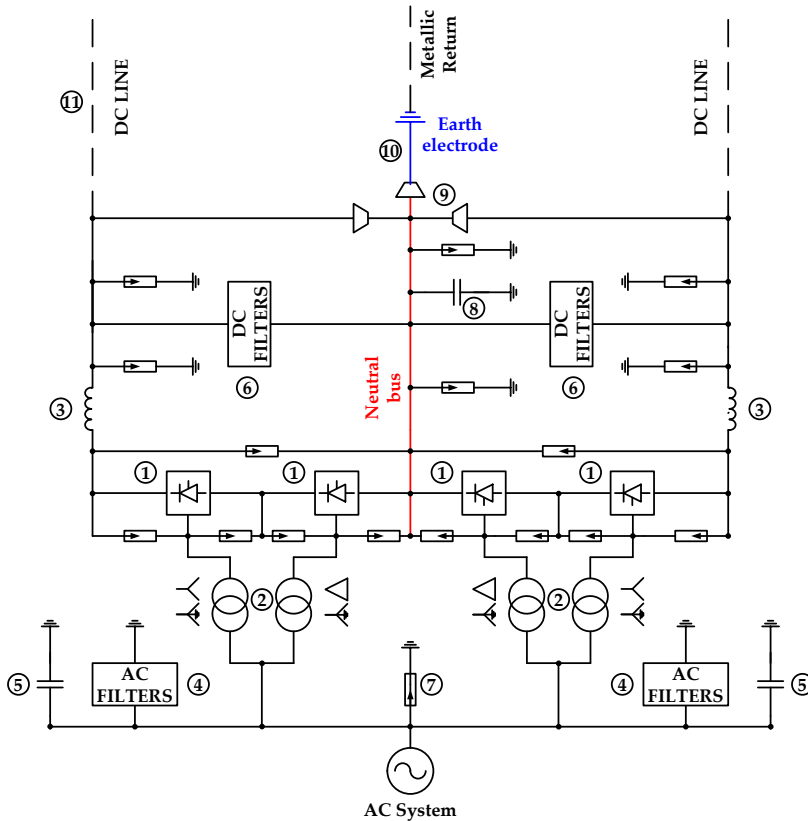
sion. However, there are other main components that integrate a HVdc transmission scheme. They perform several necessary tasks for proper system operation, reliability and compatibility with the surrounding environments.

A typical HVdc transmission arrangement, with a 24-pulse converter arrangement consisted of two 12-pulse groups, can be found on Figure 2.12, where the main components are indicated [46]⁵.

The Future of HVdc Classic

Excluding back-to-back systems (described in more details in Section 2.4), most HVdc Classic systems have distances between 180 and 1000 km, with voltages between 500 kV (± 250 kV) and 1000 kV

⁵ In a 12-pulse HVdc configuration, one of the converter bridges is connected to the ac grid using a transformer with YY0 winding configuration, while the other converter bridge will be connected to the ac grid using a transformer with YD5 winding configuration. Hence, the two converters will have each an ac three-phase phasor, but shifted by 30 degrees with respect to each other. As a result of this phase shift between the ac three-phase voltages, the characteristics harmonics of an idealised 12-pulse bridge are $12n$ for the direct voltage and $(12n \pm 1)$ for the ac current ($n \in \mathbb{N}^*$).



The numbers on Figure 2.12 correspond to the following components:

- 1) Converter bridges
- 2) Converter transformers
- 3) Smoothing reactors
- 4) AC filters
- 5) Reactive power supply
- 6) DC filters
- 7) Surge arresters
- 8) Neutral bus surge capacitor
- 9) Fast dc switches
- 10) Earth electrode
- 11) DC line

Figure 2.12: HVdc transmission system with 24-pulse converter arrangement [46].

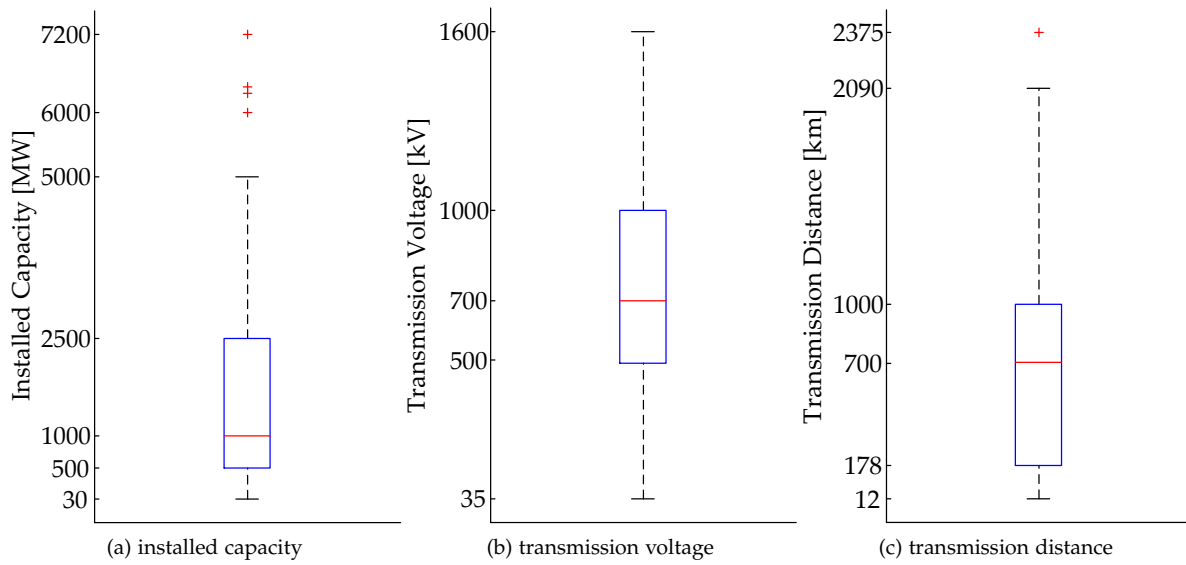


Figure 2.13: Boxplot distribution of HVdc Classic projects worldwide.

⁶ The interquartile range contains the middle 50% percent of a distribution and is unaffected by extreme values. It is defined as the difference between the first and the third quartiles (25% and 75%) of an ordered data range.

⁷ This type of converter is also referred to as current-source converter (CSC), due to the fact that it needs a fairly steady current source on its dc side to operate.

⁸ More than 270 GW of HVdc Classic systems are predicted to be installed in China alone between 2010 and 2020.

(± 500 kV), and power ratings between 500 and 2500 MW, which are the interquartile ranges of the HVdc Classic project distribution shown in Figure 2.13 [41–43]⁶.

The HVdc Classic technology is undisputed when it comes to bulk electric power transmission. Ratings up to 7.2 GW are possible using 1600 kV (± 800 kV) transmission systems – known as ultra high-voltage direct current (UHVdc) – such as the transmission link between Jinping and Sunan currently being constructed in China which, when finished, will be the largest dc transmission system in the world [48].

However, as was the case with mercury-arc valves, it is only possible to control the moment when thyristor valves turn on, but not when they turn off. The thyristor conduction has to be stopped externally by the ac network, which is why this type of HVdc converter is also known as line-commutated converter (LCC)⁷.

The fact that the HVdc Classic is line-commutated means it can control its active power flow, but it always consumes reactive power. Moreover, depending when the thyristors are turned on, the reactive power compensation needs to be circa 50-60% of the converter rated power [46]. Hence, HVdc Classic transmission systems require, for proper converter operation, strong ac networks capable of providing the necessary reactive power. Usually, part of the reactive power is provided by capacitor banks installed on the ac-side of the HVdc transmission system. Thus, HVdc Classic stations have large footprints and will be improbable on offshore wind farm installations.

Nevertheless, HVdc Classic systems continue to be installed worldwide for bulk power transmission⁸. Figure 2.14 displays the evolution of HVdc Classic systems voltage with regard to commissioning year and transmission distance [41–43].

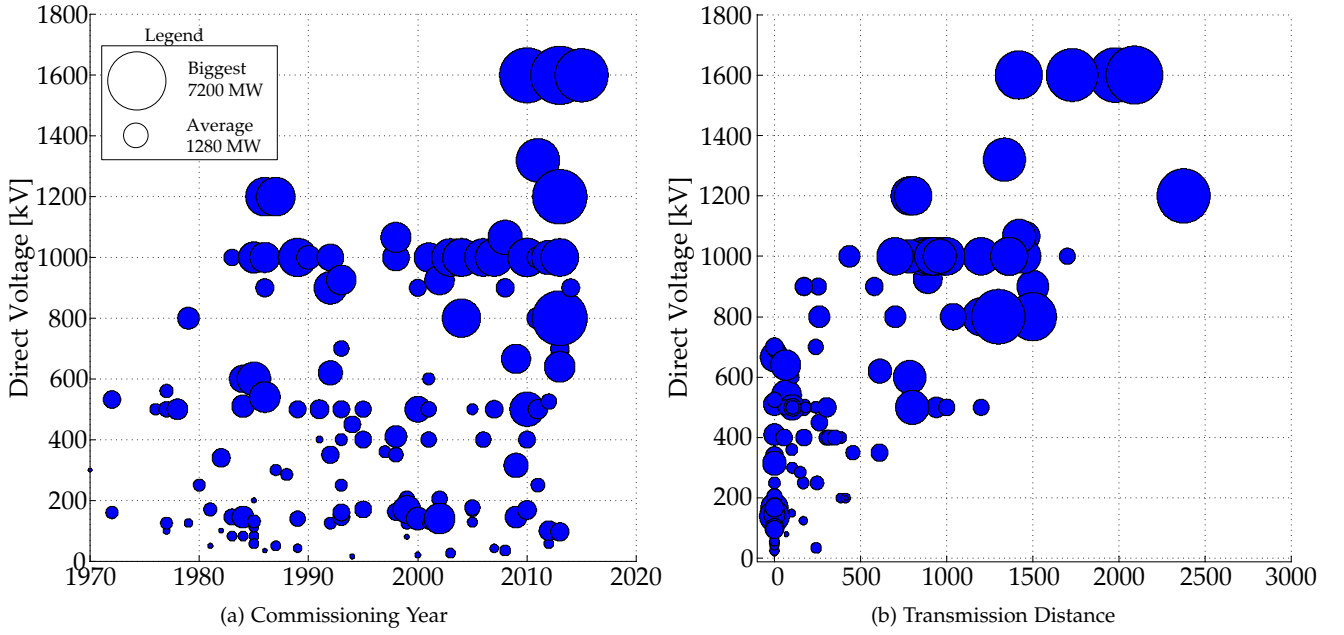


Figure 2.14: Evolution of CSC-HVdc transmission system voltage.

2.3 VSC-HVdc

Voltage-source converters for HVdc transmission were first employed in 1999, when ABB commissioned the first commercial link, with a nominal power of 50 MW, between the Gotland island and the mainland of Sweden [46]. Previously, HVdc applications utilised thyristor valves which can only be turned off by the line voltages, as discussed in the previous section.

On the other hand, voltage-source converters make use of self-commutating devices – such as the GTO⁹ and the IGBT¹⁰ – which can be commanded to turn both on and off. Therefore, a VSC provides a more controllable way to achieve sinusoidal voltages and currents at the output of the converter. However, the power ratings for a CSC-HVdc station are still much higher than those for a VSC-HVdc, making the first the current choice for bulk power transmission. Another advantage of CSC-HVdc is that it has inherent lower percentage losses [46]. Table 2.1 shows a comparison between different characteristics of the CSC and VSC-HVdc technologies [37,46].

Voltage-source converters for HVdc transmission applications are now well established inside the power industry. According to ABB, on September 2009 there were ten VSC-HVdc systems in operation [49]. Even though up till now all the VSC projects consist of point-to-point transmission systems, the VSC technology is best suited for implementation of multi-terminal HVdc transmission networks for its control flexibility [46]. There are different topologies available for creating a VSC-HVdc station such as the one depicted in Figure 2.15. However, only three main converter categories have been implemented thus far: two-level converters, three-level converters and multi-level converters.

⁹ Gate turn-off thyristor.

¹⁰ Insulated-gate bipolar transistor.

Characteristic	CSC-HVdc	VSC-HVdc
Converter	Line-commutated current-source.	Self-commutated voltage-source.
Switch	Thyristor: turn on capability only.	IGBT: turn-on and turn-off capabilities.
Age	Old: First commercial project in 1954.	New: First commercial project in 1999.
Projects Worldwide	146	15
Power Rating	up to 8000 MW	up to 1000 MW
Voltage Rating	up to ± 800 kV	up to ± 320 kV
Filters	Harmonic orders are low (e.g. 11-th and 13-th), hence high filtering efforts are needed.	Filters are tuned to higher frequencies and are, therefore, smaller and cheaper.
Footprint	Very high.	Lower.
Control	Always consume reactive power (two-quadrant operation).	Independent control of active and reactive power (four-quadrant operation).
AC Network Requirements	Needs a reasonably strong ac system to operate (high minimum short-circuit ratio, e.g. $SCR > 3$)	Can operate with a weak ac network or be used to feed islands and passive ac networks providing frequency control. Black start capability.
AC Faults	Presents commutation failure during ac faults. In case of repeated commutation failures the converter is blocked.	Can maintain active power transfer even under ac faults, fault-ride through capable.
DC Faults	Is capable of extinguishing dc-side faults via control actions.	Has no way of limiting dc-fault currents (because of the free-wheeling diodes), therefore dc breakers are needed.
Losses [% of Rated Power]	0.7%	1.5% (two-level) or 1.0% (multi-level)
Communication	Special arrangements are needed to coordinate the operation of converter stations.	Communication between the rectifier station and the inverter station in theory is not necessary. The control of each converter station operates in an independent way.
Multi-terminal Operation	Difficult since there is need for coordination between the converters (current order synchronisation) and power-flow reversal involves polarity changes through mechanical switches.	Easier to accomplish since there is little need for coordination between the interconnected converters and power-flow reversal does not involve mechanical switches.

Table 2.1: Comparison between CSC and VSC-HVdc technologies.

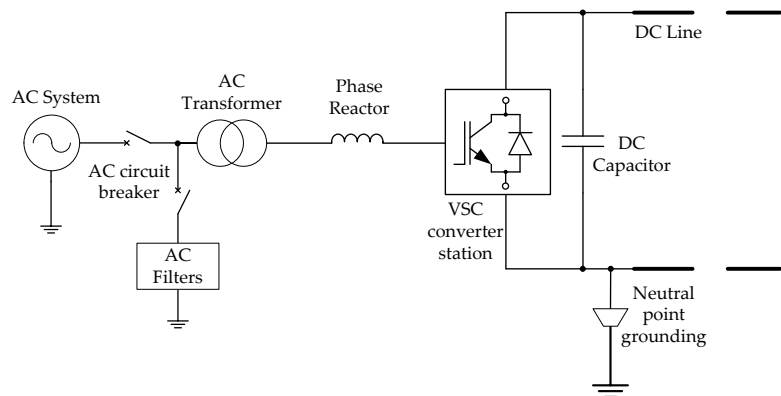
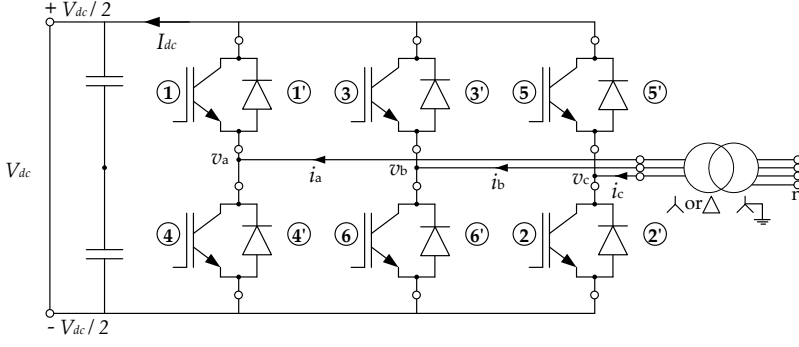


Figure 2.15: Typical layout of a VSC-HVdc station.

Two-level VSC

The two-level Graetz bridge (Figure 2.16) is the most straightforward VSC configuration that can be used to build up a three-phase forced-commutated alternating voltage. The operation principle of the two-level bridge is simple: each phase of the VSC can be connected either to the positive dc terminal, or the negative dc terminal.



The VSC in this case consists of six valves and each valve contains a switching device (IGBT) and an anti-parallel diode. The voltages and currents waveforms produced by the 3-phase two-level VSC shown in Figure 2.16 are illustrated in Figure 2.17.

As was the case with thyristors, to form a VSC-HVdc link, series connection of IGBTs is necessary to handle the higher transmission voltages. For instance, to have a VSC-HVdc with a direct voltage of ± 150 kV, at least a 100 switching devices will be necessary for each converter valve, if 3.0 kV IGBTs are used.

However, connecting IGBTs in series is not an easy task. For instance, standard IGBT packaging (wire-bond) is not inherently suitable for series connection as they normally fail into an open circuit.

To overcome these difficulties ABB applied, on its early VSC-HVdc, IGBTs on a presspack packaging. On a presspack packaging, IGBTs become modular in terms of current. In addition, these IGBTs go into a stable short-circuit state upon failure, making them suitable for series connection.

The drawback of the presspack packaging is that there is only a few suppliers worldwide. On the other hand, standard IGBT packaging has many suppliers and bigger overall market. Siemens and Alstom have chosen to use wire-bound IGBTs for their implementation of VSC-HVdc, most probably because ABB had already patented the solution with series-connected IGBTs [50].

Three-level VSC

The two-level VSC produces a voltage output similar to a square-wave, therefore highly non-sinusoidal (see v_{aN} and v_{ab} in Figure 2.17). Another main disadvantage of the two-level technique is the high dv/dt imposed on the switches during every commutation. Hence, the reason to increase the number of steps from which the direct voltage switches is to try and better approximate the alternating voltage to a sinusoidal waveform, reducing the dv/dt on the switches and improving the converter harmonic content (see Figure 2.18). The three-level VSC has less harmonic content than the two-level topology and has, additionally, also lower switching losses.

Figure 2.16: Circuit of the 3-phase two-level voltage-source converter.

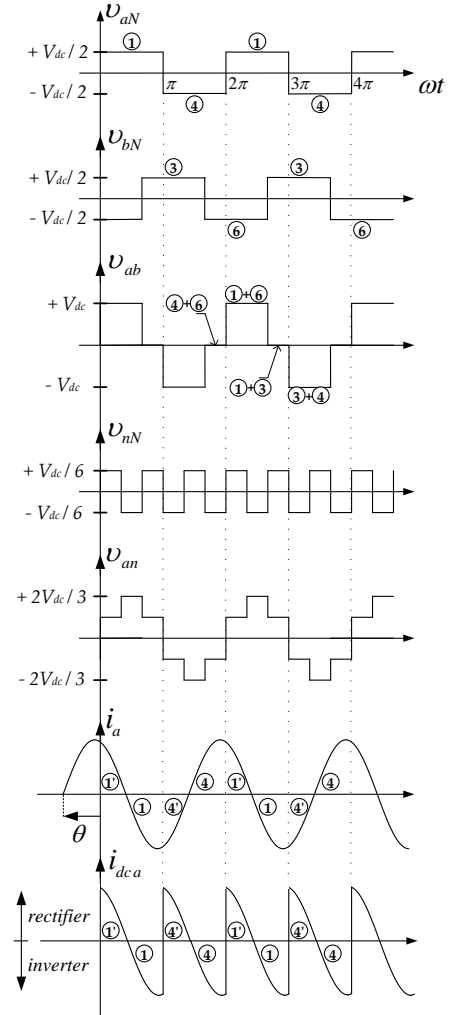


Figure 2.17: Voltages and currents waveforms of a 3-phase two-level VSC.

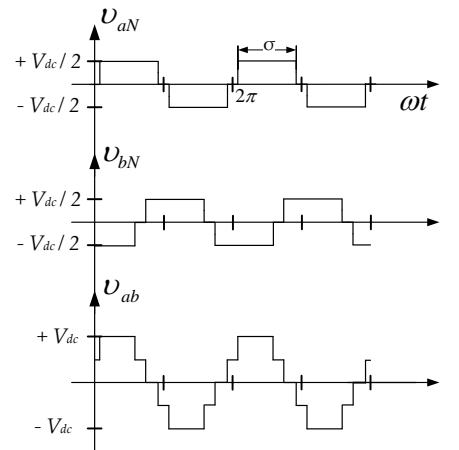


Figure 2.18: Voltage waveforms for the three-level VSC.

Figure 2.19: One phase leg of a three-level VSC: (a) diode clamping; (b) flying capacitor topology.

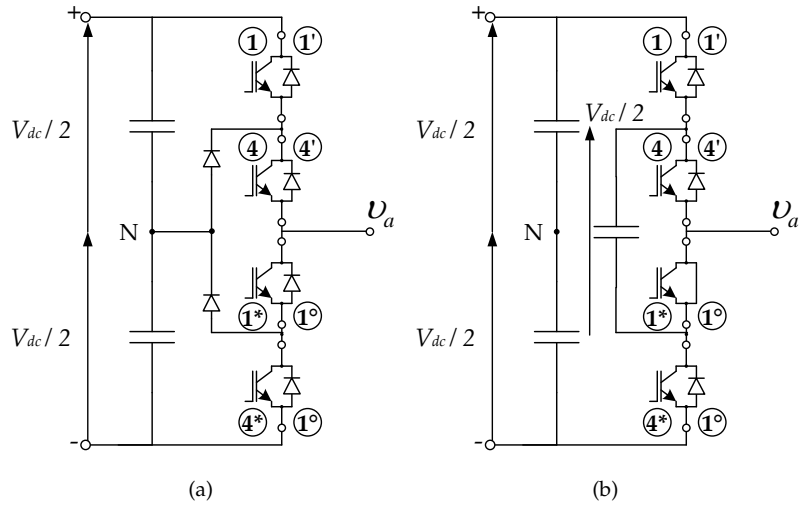


Table 2.2: Switching logic for the three-level VSC.

Topology	Voltage Level		
	$+V_{dc}/2$	0	$-V_{dc}/2$
Diode Clamping	1 & 4	4 & 1*	1* & 4*
Flying Capacitor	1 & 1*	4 & 1* or 1 & 4*	4 & 4*

¹¹ The neutral-clamped diodes complicate the insulation and cooling design of the converter valve and could be an option for back-to-back HVdc links, where higher currents can be achieved and the voltage level of the valves is kept lower.

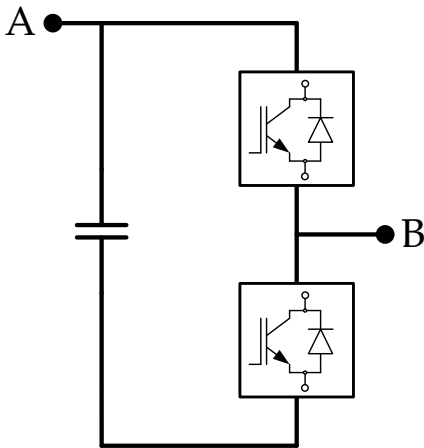


Figure 2.20: Modular multi-level converter sub-module.

The two most used three-level topologies, the neutral point clamp (NPC) and the cascaded flying capacitor, are shown in Figure 2.19.

Whether the converter uses the diode clamping or the flying capacitor topology, the voltage waveforms produced by both topologies will be the same; however, the switching logic will differ (see Table 2.2).

As previously mentioned, in HVdc systems, a converter valve is consisted of many series-connected IGBTs. In three-level converters, the total number of IGBTs is not necessarily higher than for two-level VSCs. In fact, the total number of IGBTs is approximately equal, as a three-level valve only needs to withstand half the direct voltage value when compared to a two-level valve. However, compared to two-level VSCs, three-level NPC-VSCs require more diodes for the neutral-point clamping.

The three-level concept – be it neutral clamped or flying capacitor – can be extended to a higher number of voltage levels, which can result in further improved harmonic reduction and lower switching losses [51]. Nevertheless, for HVdc applications, NPC-VSCs with a number of voltage levels higher than three have not been employed commercially [52]¹¹.

Multi-level VSC

Until recently, the only VSC topology in use for HVdc were two- or three-level configurations making use of pulse-width modulation (PWM). However, an alternative VSC-HVdc circuit was proposed in 2003, by Prof. Rainer Marquardt from the University of Bundeswehr, in Munich, Germany [53,54]. The converter circuit is based on the series-connection of several submodules (as the one depicted in Figure 2.20) usually containing two semiconductor switches and a capacitor. Nowadays, this topology is more commonly known in literature as modular multilevel converter (MMC or M2C) and its main circuit arrangement is shown in Figure 2.21.

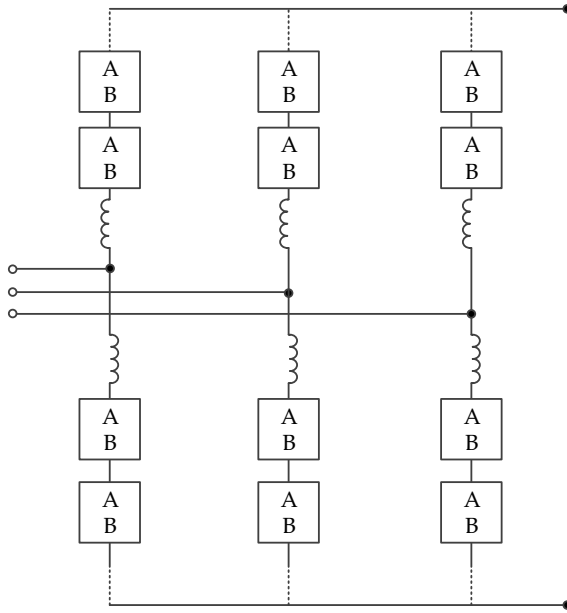


Figure 2.21: Modular multi-level converter topology.

The proposed modular multilevel converter concept has attracted significant interest for high-voltage converter applications [55]. Other than for HVdc, this VSC topology can also be utilised for other high-voltage, high-power applications such as a static synchronous compensator (STATCOM), railway power supply and large motor drives (in the tens of MW range).

Compared with the two-level and three-level topologies, one major feature of the MMC topology is that absence of a common capacitor connected at the direct voltage side. Instead, the dc capacitors are distributed into each module, while the converter is built up by cascaded-connected modules [55].

Each converter valve contains a series-connection of submodules, each one comprising a dc capacitor and a half-bridge as shown in Figure 2.20. The half-bridge is responsible to insert or bypass the submodule capacitor in the chain of series-connected submodules. Each MMC module consists of two valves which can be switched in three different ways:

1. The lower IGBT is turned on and upper IGBT is turned off: the capacitor is inserted into the circuit from A to B.
If current flows from A to B the capacitor is charged (Figure 2.22 (a)); if otherwise, the capacitor is discharged (Figure 2.22 (b));
2. The upper IGBT is turned on and the lower IGBT is turned off: the capacitor is bypassed (Figure 2.22 (c));
3. Both IGBTs are turned off: the module is blocked (Figure 2.22 (d)).

To balance the complete VSC-HVdc voltage to the required level (e.g. ± 320 kV), the control system is responsible for maintaining the average sum of inserted submodules in the upper and the lower arm at a constant level. The desired alternating voltage output is obtained by varying the difference between the number of inserted

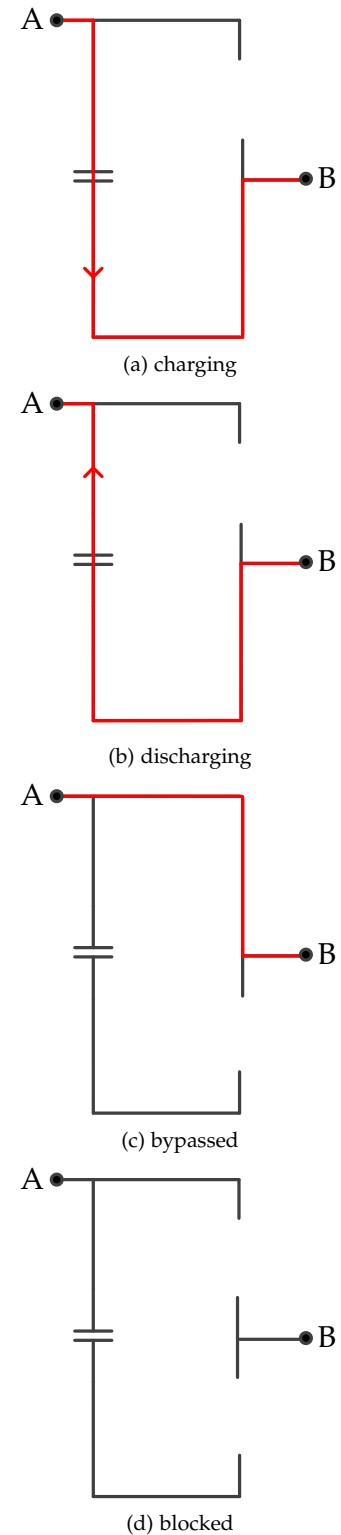
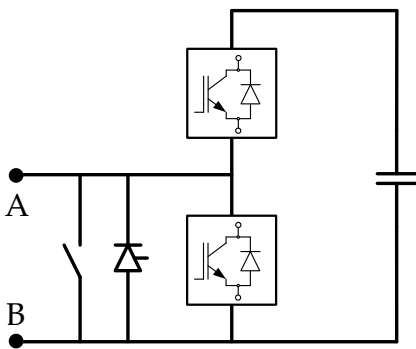


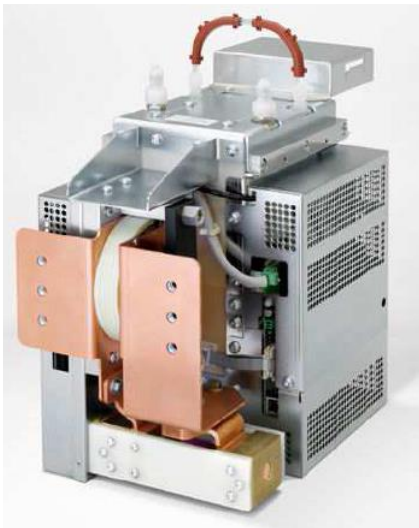
Figure 2.22: Current flow in a MMC submodule.



(a) submodule IGBT (wirebond)



(b) submodule diagram



(c) submodule picture

Figure 2.23: Siemens HVDC PLUS components [47].

¹² Typically, a 400-MW HVdc converter, such as the one used in the Transbay project, contains circa 200 submodules per converter arm.

submodules in the upper and the lower arms. In this way, the average switching frequency per device can be greatly reduced and switching frequencies as low as 150 Hz per device could be achieved. Hence, the MMC has low switching losses and its harmonic content is very small, thus, only very small filters are needed, if necessary at all [47].

Additionally, in the MMC, each step in the voltage output waveform is achieved by switching only a few semiconductor devices in the converter arm. Therefore, the stress on the phase reactors in the MMC circuit is much lower than in the two-level converter due to the smaller voltage steps.

The major challenge with the MMC is mainly a control problem: to make sure that the capacitor voltages in all the submodules are strictly controlled to avoid overvoltages. Different manufacturers apply different control principles and detailed information about their operation, as well as converter protection methods, is normally not available.

Siemens: HVDC Plus

Siemens was the first company to introduce the MMC technology for HVdc applications (commercially known as HVDC Plus). On November 2010 the Trans Bay Cable project entered in operation connecting Pittsburg, California to Potrero Hill in the San Francisco bay area.

The transmission line is long 88 km and is operated at a direct voltage of ± 200 kV. At the both line extremities 400 MW modular multilevel HVdc Plus converters were installed [33,47]. Figure 2.24 shows a bird's eye view of the first HVdc system to use the MMC technology.

Most probably Siemens has decided to use multilevel modular technology since ABB holds different patents when it comes to the series connection of IGBTs, which is needed for the manufacturing of two-level converters for HVdc applications [50].

As previously mentioned, the arm of an MMC is formed by stacking a sufficient number of submodules in series. For HVdc applications each converter arm has to have a few hundred submodules¹², depending on the rated voltage on the direct voltage side. Since it is relatively easy to scale up the converter by inserting additional modules in each arm, the MMC concept has attracted a lot of interest for high-voltage, high-power applications.

For the submodules Siemens employs standard off-the-shelf wire-bonded IGBT modules with plastic cases, as the one shown in Figure 2.23 (a). Since wire-bonded IGBTs fail as an open circuit, the submodule is a half-bridge topology equipped with a bypass thyristor and a bypass vacuum switch (see Figure 2.23 (b)). Figure 2.23 (c) displays the submodule of a Siemens HVdc plus converter.

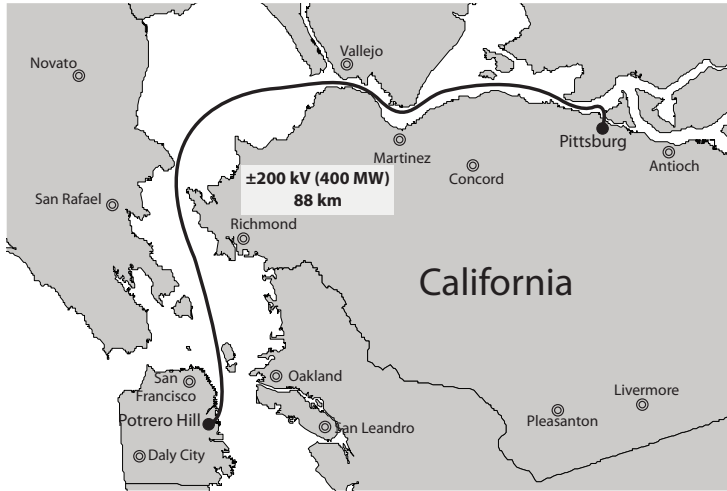


Figure 2.24: The Transbay project: the first HVdc transmission system with modular multilevel converters [33].

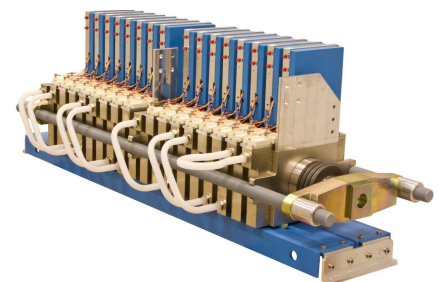
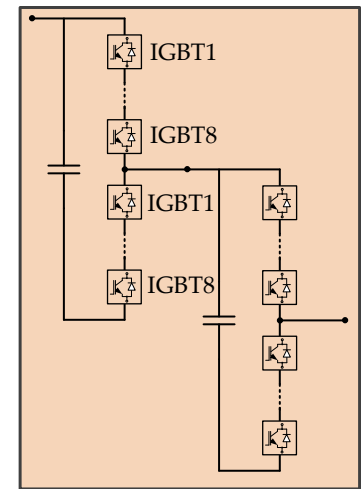
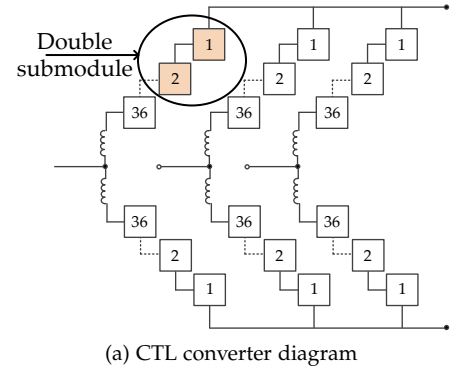


Figure 2.25: ABB HVDC Light components [40, 57].

ABB: HVDC Light

As previously mentioned, ABB was the first manufacturer to use VSC technology for HVdc transmission projects (commercially known as HVDC Light). Initially, ABB built two-level VSC by connecting several hundred IGBTs in series. However, it seems that ABB's fourth generation of VSC-HVdc will start to use multilevel converters [56]. Its multilevel converter topology is called Cascaded Two-Level (CTL) Converter, and the development will be carried out for VSC-HVdc projects with direct voltages of ± 320 kV [57].

The main circuit of the CTL converter is shown in Figure 2.25 (a). The converter half-bridges in the submodules contain strings of a small number (around eight) of series-connected IGBTs. Because of the series connection of IGBTs, the switch devices are again of press-pack packaging type, having a short-circuit failure mode (see Figure 2.25 (b)). According to ABB, the reason for the converter main circuit choice relates to protection issues [34]. Figure 2.25 (c) shows a picture of a CTL converter double submodule [57].

Comparing the CTL converter configuration with the MMC configuration (Figure 2.21), one can almost immediately see that the configuration and the connection of the submodules in the MMC and in the CTL converter are the same. In fact, the difference lies in the number of IGBT switches inside the submodule. ABB has opted for a series connection of more IGBTs inside a module (CTL topology), whereas Siemens and Alstom have opted for the original topology by Prof. Marquardt.

In July 2010, ABB was rewarded a contract for the connection of an offshore wind farm, called DolWin 1, using VSC-HVdc. The converter nominal rating will be 800 MW at ± 320 kV in a bipolar configuration. The installation, planned to be commissioned in 2013, will consist of a submarine cable part of 75 km and an additional underground cable part of 90 km. Interestingly, the project will initially serve one 400 MW offshore wind farm, while a second one will be connected afterwards.

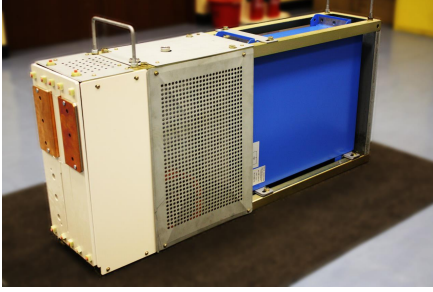


Figure 2.26: Alstom HVDC Maxsine submodule [50].

The IGBTs employed by Alstom, which are cooled via water heat sinks, are rated for 1.5 kA and 3.3 kV. The devices are off-shelf and are typically operated between 1.8 - 2.0 kV and 1000 - 1200 to allow for safety margins. If a sub-module IGBT fails in an open circuit, a mechanical switch is used to short circuit the submodule. The submodules are mounted in a rack and eight of them form a complete power module. The complete submodule weighs circa 160 kg and is 150 cm long, 65 cm high, and 30 cm thick [50].

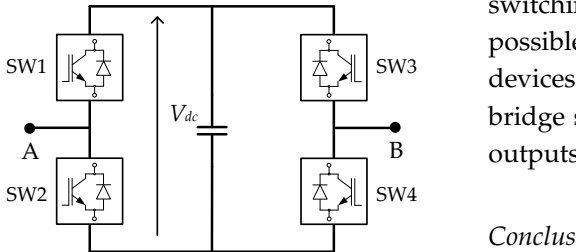


Figure 2.27: Diagram of a full-bridge MMC submodule.

Table 2.3: Voltage output of a full-bridge MMC submodule.

Switches (SW)	Output voltage (v_{AB})
1 & 4	$+V_{dc}$
1 & 3	0
2 & 4	0
2 & 3	$-V_{dc}$

ALSTOM: HVDC Maxsine

The latest manufacturer to start offering VSC for HVdc applications, commercially available under the name of HVDC MaxSine, was Alstom [58]. As Siemens, the company is also endorsing the MMC topology, and it has signaled that it might use full-bridges inside each submodule instead of the half-bridges standard [50,58]. The submodule, which is shown in Figure 2.26, contains the IGBTs, the dc capacitor (oil free design), the gate drives for the IGBTs and a fast acting mechanical bypass switch.

What is interesting about Alstom's VSC-HVdc solution is the use of the full-bridge, instead of the half-bridge, inside the submodules, which affects the total number of switching devices and ultimately the final cost of the VSC-HVdc station. A possible justification for the choice of full-bridge submodules is that Siemens is now holder of a different number of patents covering the MMC topology with half-bridge submodules. Nevertheless, the application of the full-bridge submodules, even though surely more costly, could bring some advantages.

In VSC-HVdc transmission links there is not usually the need to invert the converter direct voltage. However, Alstom claims that by using the MMC with full-bridges it would be possible to reverse the VSC dc-side voltage, making it easier to operate alongside HVdc Classic converters. An important additional advantage of the full-bridge submodule is that it can handle dc-side short circuits more effectively. The half-bridge options still provides a path from the ac to the dc side through the anti-parallel free-wheeling diodes of the switching components. However, with the full-bridge design it is possible to fully interrupt the current by opening all the switching devices inside the module. Figure 2.27 shows a diagram of the full-bridge submodule and Table 2.3 displays the possible direct voltage outputs based on the switching logic.

Conclusions on Multi-level VSC

All the commercially available multi-level converter solutions for VSC-HVdc are somehow similar to each other. They rely on the same basic circuit, the Marquardt converter, which in turn is fairly similar to the chain-link converter.

The ABB solution uses series-connected press-pack IGBTs in the converter arm since ABB was already experienced with the series connection of IGBTs from the two- and three-level converters. However, its multi-level implementation has basically the same operational characteristics as the original idea by Marquardt.

Siemens and Alstom are using the Marquardt topology as it was conceived, i.e. without the series connection of switching devices. Siemens has opted for a half-bridge submodule while Alstom has opted for a full-bridge submodule.

In normal operation, the full-bridge means a substantial over-investment in switching semiconductor components, and further in-

creased losses. However, it could have some advantages in future meshed HVdc networks. The full-bridge MMC can operate with reduced and even reversed direct voltage, hence, it could be connected with LCC-HVdc converters. Moreover, in case of dc short circuit, the fault could be cleared by blocking all the switching devices, i.e. effectively isolating the converter ac from its dc side, without the need for opening ac circuit-breakers¹³.

2.4 HVdc Transmission System Configurations

Independently from the converter technology – CSC-HVdc or VSC-HVdc – and topology, there are three main configurations for HVdc transmission systems: monopolar, homopolar and bipolar [37,46].

Usually, there are more than one converter connected in parallel on the ac side of the transmission system, to reduce filter needs due to harmonics, and in series on the dc side to achieve the desired pole voltage, as in the 12-pulse converter topology for CSC-HVdc and multi-level topologies for VSC-HVdc [46,47].

Figure 2.28 depicts a single-phase representation of a HVdc converter station connected to a three-phase ac system via a transformer. The converter topology is abstracted as the main HVdc transmission system configurations are distinguished by their dc circuit schemes.

¹³ Direct current contingencies in multi-terminal networks are further analysed in Chapter 7. Regardless of the converter configuration employed, a VSC can always be seen as an ideal voltage source where the control system can independently assign the converter output voltage magnitude, phase and frequency to form a sinusoidal waveform, an aspect which is further explored to model VSC converters in Chapter 4.

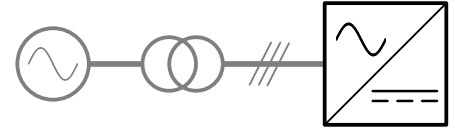


Figure 2.28: Single-phase representation of a HVdc converter station connected to an ac system.

The HVdc transmission system configurations are defined independently from the converter station topology and technology.

Monopolar configuration

The monopolar arrangement is the most basic HVdc transmission system configuration. As the name suggests, in this configuration only one pole, mostly of negative polarity to reduce corona effects, is used [46]. Figure 2.29 shows the possible monopolar configurations for HVdc transmission systems. They are preferred when long distances through overhead lines or submarine cables are involved.

Capital investment costs and transmission losses can be minimised if the return current can be established through ground as only one dc cable is needed (Figure 2.29 (a)). However, in highly congested areas, or areas with high earth resistivity, or when fresh water crossing is involved, it may not be possible to use ground return. Whenever environmental issues, or interactions with metallic structures, constraint the use of ground return, a metallic return is used (Figure 2.29 (b)). If the dc side of the transmission system is grounded a LVdc cable, which does not require full insulation, can be used. However, whenever the dc-side of the HVdc transmission system is grounded, special transformers capable of withstanding dc stresses are needed [37].

A symmetric monopole configuration (Figure 2.29 (c)) can be utilised to avoid special transformers, however, in this case, two dc cables with full insulation are needed. Finally, there is a main drawback which is common to all monopolar configurations: if a cable or converter fault occurs the whole HVdc transmission becomes momentarily offline.

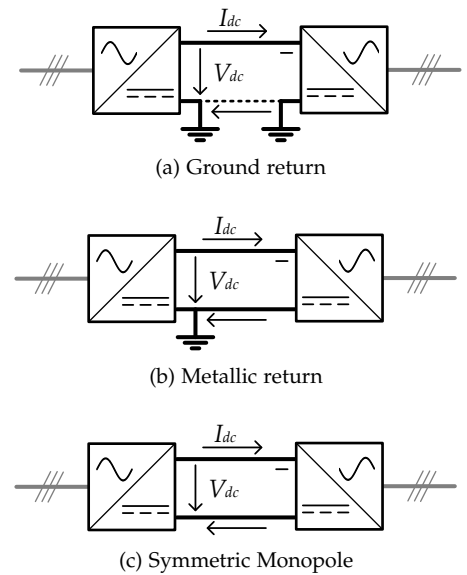


Figure 2.29: Monopolar HVdc transmission system configurations.

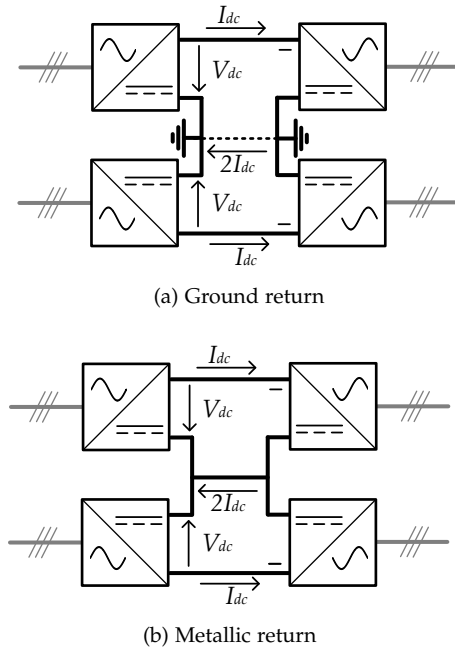


Figure 2.30: Homopolar HVdc transmission system configurations.

Homopolar configuration

In the homopolar configuration two HVdc cables of the same polarity are used. As was the case in the monopolar configuration, usually a negative polarity is chosen to due to smaller corona losses, as well as lower radio interferences when transmission is done via overhead lines. Figure 2.30 shows two HVdc transmission system configurations using the homopolar arrangement.

Since the polarities of both pole conductors are identical, this HVdc transmission system configuration has the advantage of reduced insulation costs [37]. Additionally, it does not suffer from the main drawback of monopolar configurations, i.e. upon a HVdc cable or single converter fault, the whole transmission system will not become offline. Instead, the converter not affected by the fault can be reverted to feed the remaining pole.

The main disadvantage with the homopolar arrangement is, however, the constant need of a return path and the high current associate with it, which can be equal twice the nominal value in rated conditions, as the current from each pole share the same return path.

The homopolar configuration shown in Figure 2.30 (a) is usually not feasible due to environmental restrictions to the high ground currents [46]. Therefore, the use of a metallic return LVdc cable, as shown in Figure 2.30 (b), will probably need to be taken into consideration when designing the transmission system.

Bipolar configuration

For a certain power rating, a bipolar configuration is more expensive than a monopolar configuration. Hence, a bipolar configuration is usually employed when the power to be transmitted is higher than the capacity of a single pole in a monopolar configuration [42]. However, differently from the homopolar configuration, the bipolar one makes use of two HVdc cable with different polarities, carrying the dc current in opposite directions. During normal operation the currents in each cable have the same amplitude, and there is no current in the return path. Figure 2.31 shows two HVdc transmission systems with a bipolar configuration.

In case of imbalances, the current can usually flow through ground if there are no environmental restrictions (Figure 2.31 (a)) or through a metallic return cable ((Figure 2.31 (b))). The third cable can have a low insulation level (LVdc cable), and it may also serve as shield wire in case of overhead lines, which are usually bipolar (or homopolar) as, for symmetry reasons, transmission towers are mechanically better suited to support two cables [46].

Even though not necessary, grounding is often provided for the bipolar configuration. The absence of a ground return path could lower initial capital expenditures but, it would cancel one of the bipolar configuration main advantages: its redundancy capability, i.e. its ability to withstand outages. If there is no return path for the current, the whole HVdc transmission system will be made offline

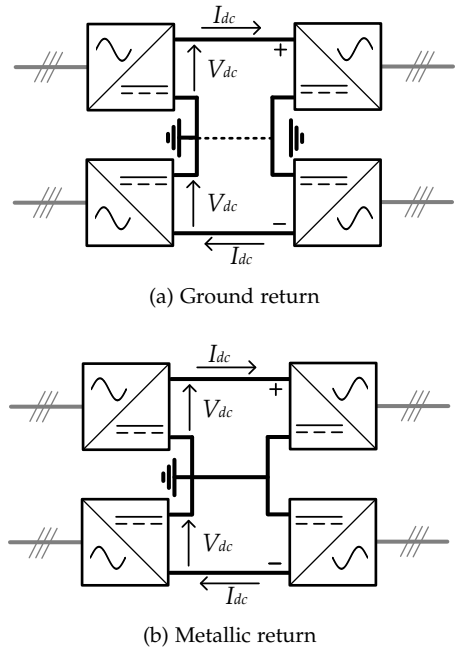


Figure 2.31: Bipolar configuration.

during faults.

However, if a ground path is provided, the bipolar configuration offers redundancy capability in case of a fault in one of the HVdc cables or HVdc converters. Figure 2.32 shows the current path – in red – during contingencies in a bipolar HVdc transmission system.

During a HVdc cable fault (Figure 2.32 (a)), half of the HVdc transmission system will still be available for operation. The actual transmission capacity can be higher than 50%, depending on the remaining cable and converter overload capabilities. Monopolar operation is possible for converter outages (Figure 2.32 (b)), but a short interruption will take place before high-speed dc switches can bypass the faulted converter [46].

Back-to-back configuration

Back-to-back configurations are usually employed when a connection between two asynchronous ac systems – which can have equal or different frequencies – must be performed, but there is no need for transmission lines or cable connections [37]. In back-to-back configurations, the converter valve halls, control equipment, cooling devices and transformers of both converter stations can be combined into one single building. As there is no need for dc cables, usually the currents are kept high while voltages are kept low – circa 150 kV or less – as HVdc valve costs are voltage dependent [46]. Additionally, there is no need for a telecommunication link between the two HVdc converter stations, which simplifies the control equipment.

For small ratings (lower than 500 MW) usually monopolar configurations are used, whether for high ratings bipolar configurations have to be employed. Figure 2.33 displays a back-to-back HVdc system with a monopolar configuration.

Approximately 25% of all HVdc transmission systems are back-to-back configurations using CSC-HVdc technology due to the high current capacities of thyristor valves [41–43]. Their average power is circa 480 MW and the average voltage is 160 kV (see Figure 2.14).

2.5 From Point-to-Point to Multi-Terminal DC Networks

The advent and consolidation of current-source converters for HVdc applications helped to increase the interest of interconnecting more than two converter stations to form multi-terminal dc networks¹⁴. However, out of more than 100 HVdc projects worldwide, only two are known for having more than two terminals: the Hydro-Québec – New England scheme, in Canada; and the SACOI scheme, between Italy and France [43,46].

Hydro-Québec – New-England

The first multi-terminal HVdc system to be planned and constructed was the Hydro-Québec – New England link built in Canada. The project had two phases: during Phase I, the HVdc transmission line

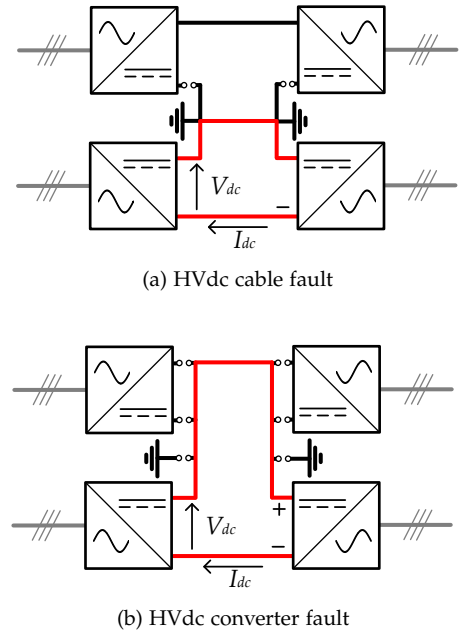


Figure 2.32: Bipolar configuration during a fault in the (a) HVdc cable and (b) HVdc converter.

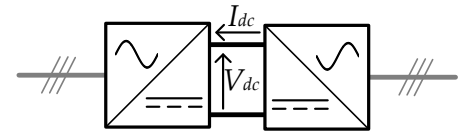


Figure 2.33: Back-to-back configuration.

¹⁴ By 1980, more than 70 different articles had already been published with studies covering different aspects of multi-terminal dc systems such as network topology, the need for interrupting devices, system stability, control strategy and economic analysis [59–62]. The outlook at that time was very optimistic that MTdc networks were technically and economically feasible.



Figure 2.34: Aerial view of Hydro-Québec – New England MTdc network [64].

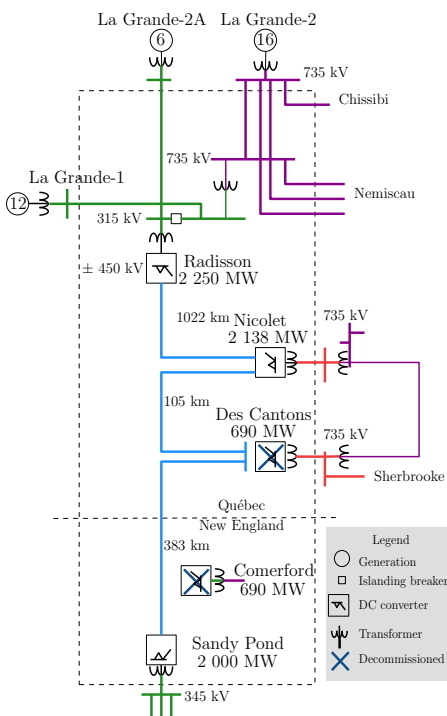


Figure 2.35: Single line diagram of Hydro-Québec – New England MTdc network [65].

¹⁵ “The Comerford and Des Cantons converter stations were originally to have been integrated into the multi-terminal scheme to enable even more operating flexibility, allowing five stations to operate simultaneously. After reassessing the benefits of this additional flexibility, the owners, however, elected to suspend the commercial multi-terminal integration of Des Cantons and Comerford” [64].

had only two terminals connecting Québec (Des Cantons station) to New Hampshire (Comerford station). This first point-to-point transmission line, commissioned in October 1986, was long 172 km, operated at a bipolar direct voltage of ± 450 kV and carried 690 MW, which was the rated power of both CSC-HVdc converter stations [63,64].

During Phase II, three more converter stations were planned. In 1990, the Radisson converter station (2250 MW), in Québec, and the Sandy Pond converter station (2000 MW), in Boston, were commissioned [64]. The goal was to bring power from La Grande hydroelectric power plants near Québec to the Boston load centre.

The last converter station to be commissioned in the Hydro-Québec – New England HVdc link was Nicolet (2138 MW), near Montreal, which was commissioned in 1992 [64]. Figure 2.34 shown an aerial view of the MTdc network.

After Phase II, the MTdc network was initially thought to operate with all five terminals. The Hydro-Québec – New-England MTdc network did not use dc breakers, hence, dc-side contingencies are dealt with only through control actions. However, due to performance issues, the initial two terminals were decommissioned and never connected to the later three terminals, which still form a MTdc network with 1480 km of overhead dc cables. Figure 2.35 shows a single line diagram and the distances between the CSC-HVdc converter stations.

Nowadays, the Hydro-Québec – New-England MTdc network can operate in three different configurations:

- as a point-to-point HVdc link (e.g. between Radisson and Sandy Pond or Nicolet and Sandy Pond);
- as a multi-terminal HVdc network (all three terminals are connected);
- as a hybrid configuration when there’s a pole outage at Radisson or Sandy Pond and three converters become connected on one pole and two converters are connected on the other pole.

According to ABB, the two initial converter stations were decommissioned after reassessment of the additional benefits they would bring to the three-terminal MTdc¹⁵.

SACOI

The other MTdc project, also a three-terminal network, is the SACOI HVdc transmission system. This link connects the mainland of Italy to the islands of Sardinia and Corsica through circa 300 km of HVdc overhead lines, and 120 km of submarine cables [46].

Initially, in 1967, the first connection between Sardinia and mainland Italy was done via two 6-pulse mercury-arc valve converters in a monopole configuration with ground return. This early transmission line had a capacity of 200 MW and operated at a voltage of 200 kV.

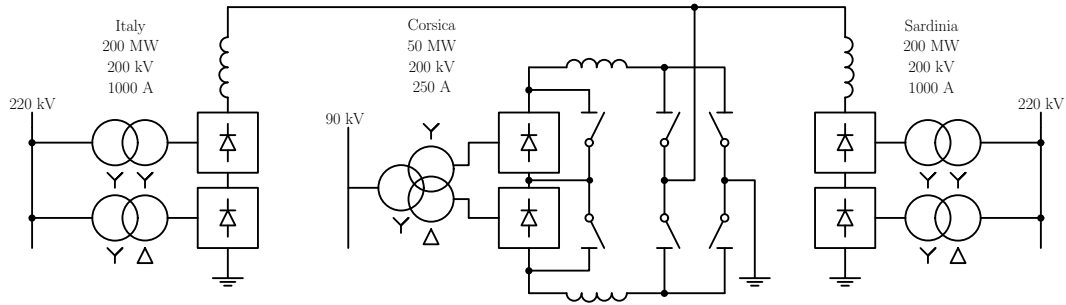


Figure 2.36: Single line diagram of the SACOI MTdc network [66].

The SACOI system became the first multi-terminal HVdc network in 1987 after the Lucciana converter station (50 MW) was commissioned in Corsica [66]. At that time, the new converter station used thyristor converters whereas the original two still used mercury-arc converters.

In 1992, the Sardinian and the mainland Italian converter station were upgraded to use thyristor technology, and their power ratings were increased from 200 to 300 MW. Figure 2.36 shows a single line diagram of the SACOI MTdc network [66]. Figure 2.37 shows an aerial view of the SACOI HVdc transmission lines [67].

MTdc Networks Development

The HVdc industry has already 3 decades of experience with multi-terminal HVdc networks. However, since the 1990s no other project with more than 3 terminals has been built using the HVdc technology based on current-source converters.

When the number of converter stations, rectifiers and inverters, grows in a HVdc transmission system which uses the CSC technology, also the complexity of the master control increases [68]¹⁶. Since the master control is responsible for proper coordination between the terminals, also the need for fast telecommunication link increases. The telecommunication is needed for the synchronisation of the converters current orders, identifications and actions for clearing dc faults and start-up of the system after a power outage [49,68].

Moreover, when using HVdc Classic technology to form multi-terminal networks, the reversal of power flow involves complex mechanical switchgear since the current flow through the thyristor valves cannot change direction [46]. An example of the high number of switches and the complexity involved is shown in Figure 2.38, which displays the switchgear arrangement in the one line diagram of the Hydro-Québec – New England MTdc network [65].

The increased complexity of the master control, the need for fast communications links, which may have not been available at the time; and the inability to change the direction of the current may have constituted the reasons why multi-terminal HVdc networks using CSC-HVdc were not further developed.

Nevertheless, even without being able to build meshed networks, almost 200 GW of HVdc transmission capacity is installed, or un-

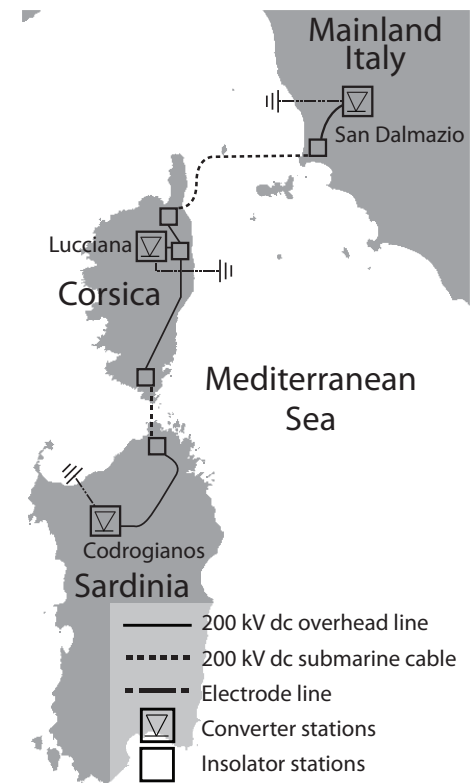


Figure 2.37: Aerial view of the SACOI MTdc network [67].

¹⁶ On the other hand, according to Dr. Gregor Czisch from the University of Kassel, an algorithm for controlling complex HVdc multi-terminal networks, without the need for a central master control and with a high numbers of converters stations was already available since that time [69]. This algorithm is called Combined and Coordinated Control Method (CCCM) and was created by control specialist Franz Karlecik-Maier.

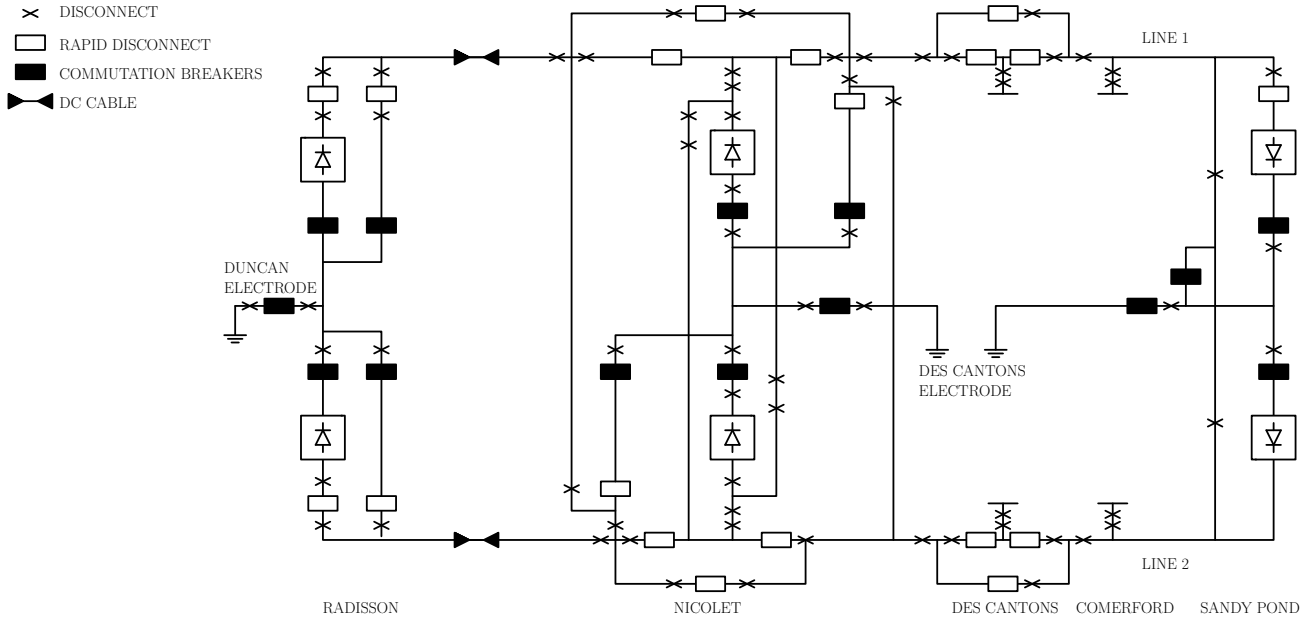


Figure 2.38: Switchgear arrangement of the Hydro-Québec – New England MTdc network [65].

der construction, in more than 140 projects throughout the world [41–43] (see Figure 2.8). In the meantime, the total installed capacity is continuously growing with countries such as China, India and Brazil building long dc transmission lines to integrate remotely located generation sources. China alone plans to build more than 30 HVdc links, which amount to circa 270 GW, up to 2030 [16,17].

Hence, HVdc has become a reality and it represents nowadays an important share in the transmission capacity in many countries around the world.

2.6 MTdc Network Topologies

Multi-terminal direct current networks are characterised when three or more converter stations become interconnected through the dc side of the transmission system¹⁷. The MTdc configurations can be classified according to the type of HVdc technology implemented at the converter stations:

- CSC-MTdc: all the converter stations use the line commutated current-source converter HVdc technology;
- VSC-MTdc: all the converter stations use the forced commutated voltage-source converter HVdc technology;
- Hybrid-MTdc: when both HVdc technologies – CSC and VSC – are used together.

Hitherto, both existing multi-terminal networks – the Hydro-Québec – New England and the SACOI transmission system – use HVdc Classic technology, therefore they form CSC-MTdc networks. Nevertheless, independently of the converter technology used, as shown

¹⁷ The situation, depicted in Figure 2.39, in which two (or more) HVdc converter stations become interconnected by the ac side of their transmission system is known as multiple infeed of HVdc into ac networks (or reinforcement of ac networks using HVdc) and does not characterise a multi-terminal dc network.

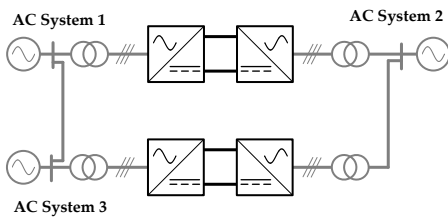
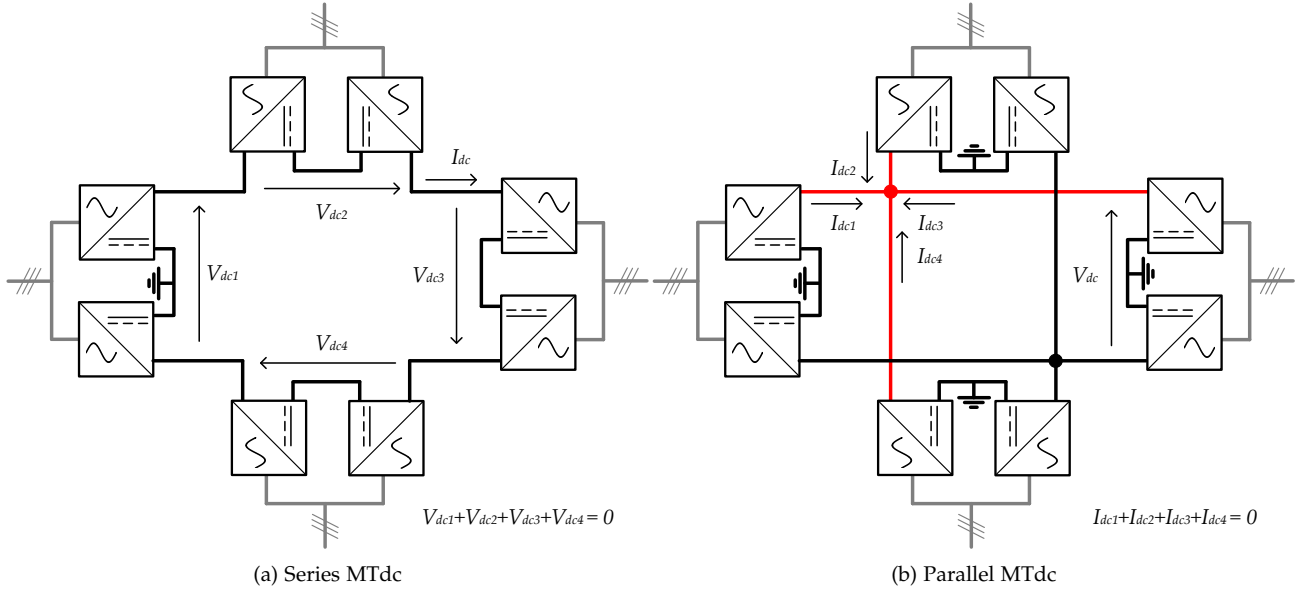


Figure 2.39: Multiple infeed of HVdc lines into ac networks.



in Figure 2.40, to form a multi-terminal dc transmission system the converter stations can be connected in two ways: series or parallel [70].

Figure 2.40: Multi-terminal dc network with bipolar HVdc stations connected in: (a) series; (b) parallel.

Series MTdc Network

In a series connected MTdc network, all converter stations share the same dc current, whilst their voltages will vary according to the power to be extracted or delivered to its ac network. The MTdc is grounded in only one point, which can be arbitrarily chosen, but will affect the insulation needs of the different converter stations.

Parallel MTdc Network

In a parallel connected multi-terminal dc network, all the converter terminals share the transmission system direct voltage. The MTdc transmission systems using parallel connections can yet be grouped into two categories: radial and meshed networks. Figure 2.41 shows the difference between a radial connected MTdc network and a meshed one¹⁸.

¹⁸ For simplicity, a monopolar HVdc configuration is shown in Figure 2.41. If larger powers needs to be transmitted, most probably a bipolar configuration would be used instead.

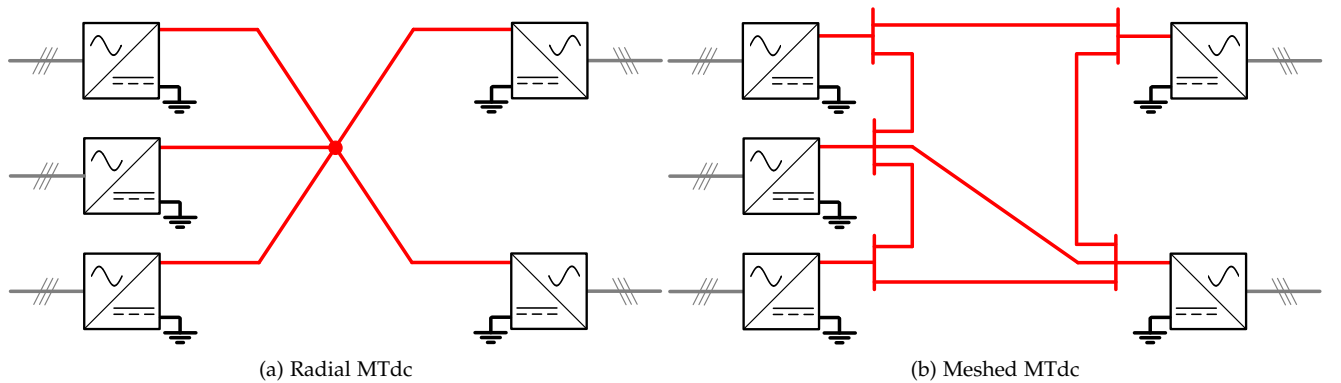


Figure 2.41: Multi-terminal dc network with monopolar HVdc stations connected in parallel: (a) radial; (b) meshed.

Characteristic	Series MTdc	Parallel MTdc
Power Flow Reversal	In CSC-MTdc power flow reversal can easily be achieved by inverting the converter voltages. With VSC-MTdc it would not be easy to invert the converters voltage polarity, thus power flow reversal would involve mechanical switches.	In CSC-MTdc the current direction cannot be inverted, hence, there is need for mechanical switches. In VSC-MTdc the current direction can easily be inverted, hence power flow reversal can be achieved via control actions.
HVdc Terminal Power Rating	Depends on converter voltage rating (cheaper for smaller powers).	Depends on converter current rating.
Losses	Higher losses, which can be minimised by always operating with the minimum current possible.	Lower losses.
Insulation	Is difficult in series connection as the voltages in the MTdc network vary.	All converters need to be insulated to the rated voltage.
DC Faults	A permanent fault in a transmission line would make the whole MTdc network unavailable.	A permanent fault in a transmission line would only make the affected terminal unavailable (in meshed MTdc networks normal operation is still possible).
AC Faults	Leads to overvoltages in the remaining terminals.	Leads to overcurrents in the remaining terminals.
Protection	In series CSC-MTdc, dc faults can be handled via control actions. VSC-MTdc will need dc breakers.	For clearing dc faults parallel MTdc networks will need dc breakers.

Table 2.4: Comparison between series and parallel MTdc networks.

¹⁹ Rated operation is possible if the remaining elements of the network are capable of carrying the additional power.

In radial networks, the loss of a dc transmission line section would result in total service interruption of the interested converter terminal; whereas in meshed MTdc networks rated operation would still be possible although with higher transmission losses ¹⁹.

The pros and cons of the series and the parallel MTdc networks are listed in Table 2.4 [70]. Hitherto, only parallel MTdc transmission system have been built.

2.7 Conclusion

Due to its physical characteristics and improved controllability, modular multilevel VSC-HVdc transmission systems are the best available technology for integration of offshore wind farms.

Initially, as the power to be transmitted in offshore grids will be small, the best configuration choice is the symmetric monopolar with metallic return. This configuration does not need special transformers, it allows for later expansions into bipolar topologies, and has the best performance regarding dc contingencies, as it will be shown in Chapter 7.

Based on all the analysis performed in the chapter, Figure 2.7 depicts a classification system and highlights the best HVdc technology, configuration and network topology for the development of an offshore transnational grid in the North Sea.

The development of VSC-HVdc transmission systems has brought back the interest in establishing multi-terminal dc networks for different applications, such as supergrids and electronic power distribution systems [15,71]. System integration aspects of multi-terminal dc networks are discussed next in Chapter 3.

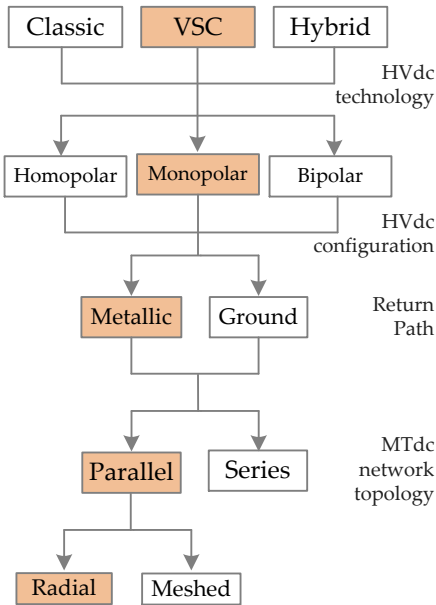


Figure 2.42: Classification of MTdc transmission systems.

Part II

Steady-state Analysis

3

Network Operation and Power Flow

Expensive projects are vulnerable because they take a long time and must be sustained across changeovers in political leadership as well as through downturns in the economy. Raise the cost of a project above \$20 billion to \$30 billion, and if there's not a weapon at the other end of the experiment, or you won't see the face of God, or oil wells aren't to be found, it risks not getting funded.

Neil deGrasse Tyson - Space Chronicles

As it was shown in Chapter 2, the VSC-HVdc technology using modular multilevel converter is currently the best choice for the development of MTdc networks. However, when several VSC-HVdc stations are connected together, the ability to control the power flow inside the MTdc network remains a challenge. The objective of Chapter 3 is to understand how dc networks operate, i.e. how does the power flow inside them. Initially, the chapter describes why nowadays, for a growing number of applications, direct current is preferred over alternating current. After that, it analyses how to evaluate the right transmission system technology for offshore wind farms. For large, long and costly projects – such as the North Sea Transnational Grid – it then introduces the importance of choosing the right system architecture and system integration strategy beforehand. It progresses to show how a load flow algorithm is key to understanding how MTdc networks operate. Finally, using the developed load flow algorithm, the resilience of dc networks against faults in the surrounding ac networks is first tested in a N-1 security analysis.

- 3.1. Why Use Direct Current
- 3.2. Transmission system selection for offshore wind farms
- 3.3. MTdc Network Architecture & System Integration
- 3.4. Load Flow in MTdc Networks
- 3.5. MTdc Network Security (N-1 Analysis)
- 3.6. Conclusion

This chapter is based on the following publication:

R. Teixeira Pinto and P. Bauer, "The Role of Modularity Inside the North Sea Transnational Grid Project: Modular Concepts for the Construction and Operation of Large Offshore Grids," in *Proceedings of the Renewable Energy World Europe Conference*, Milan, Italy, June 2011, pp. 1- 19.

3.1 Why Use Direct Current

In the end of the nineteenth century, ac electricity was preferred for transmission purposes mainly because, as it was easier to achieve higher voltages by means of a transformer, it had lower transmission losses. Additionally, generating electricity via three-phase synchronous generators was easier, cheaper and more efficient than using dynamos¹.

However, as soon as practical HVdc converters were made possible, HVdc transmission systems proliferated around the world. Electrical engineers advocating the use of dc never forgot its technical, economical and environmental advantages over ac technology [37].

A list of reasons is given next on why nowadays dc systems are preferred for applications such as microgrids, electronic power distribution systems and supergrids for integration of renewable energy.

1. Greater power per conductor

Consider a HVac and a HVdc system with equal current ratings, i.e. $I_{ac} = I_{dc}$, the same number of conductors, and insulation length in each conductor². The ratio between the power transmitted by the HVdc system, P_{dc} , and the power transmitted by the HVac system, P_{ac} , is given by:

$$\frac{P_{dc}}{P_{ac}} = k_1 \frac{k_2}{k_3} \quad (3.1)$$

where;

k_1 is the relationship between the dc conductor maximum voltage with regard to ac conductor maximum voltage;

k_2 is the relationship between the ac conductor insulation voltage and its rated voltage and;

k_3 is the relationship between the dc conductor insulation voltage and its rated voltage.

Substituting in (3.1) typical values for the insulation constants (k_1 , k_2 and k_3) shows that an overhead HVdc line can take 1.5 to 2.1 times more power than a HVac overhead line, and an underground HVdc line can take 2.9 to 3.8 times more power than an underground HVac equivalent [46]³. This means HVdc systems carry more power per conductor used.

2. Higher voltages possible

The relationship in (3.1) shows more power can be delivered using HVdc systems because it achieves higher voltages than HVac systems. The highest alternating voltage achieved commercially has been 1200 kV on a line connecting Russia and Kazakhstan [72]⁴. In contrast, since 2010, HVdc voltages of up to 1600 kV (± 800 kV) were already possible, such as in the Xiangjiaba – Shanghai HVdc transmission line in China [47].

¹ see Appendix C for more details.

² This would be the equivalent of a double circuit 3-phase HVac transmission system and 3 bipolar HVdc system, totalling 6 conductors each:

$$\begin{aligned} P_{ac} &= 6EI_{ac}\cos\phi \\ P_{dc} &= 6V_{dc}I_{dc} \end{aligned}$$

where;

E is the ac system phase voltage [V] and;
 $\cos\phi$ is the ac power factor [pu].

As the current ratings and the number of conductors are the same, also the transmission losses are equal.

³ Typical values of k_1 are between 1 – $\sqrt{2}$ for overhead lines and 2 – 3 for underground cables;
Typical values for k_2 and k_3 are 2.5 – 3.0 and 1.7 – 2.0, respectively.

⁴ The line went in operation in 1988 and was dismantled in 1996.

3. Simpler line construction

Usually HVdc transmission lines only comprises 2 cables, whereas HVac lines will require a third one. Moreover, due to steady-state and transient stability limits of ac lines, to transmit the same power more ac circuits are needed [46]. The result is that HVdc needs lesser insulators, have cheaper and smaller towers, and a narrower right-of-way (ROW).

Figure 3.1 shows that for the transmission of 2000 MW, using a ± 500 kV HVdc line, the ROW is circa 50 m. For a HVac line, due to stability limits, the ROW is doubled with regard to that of a HVdc line, since an additional three-phase circuit is needed to transmit the same 2000 MW [73]. Therefore, building a HVdc line is usually 30% cheaper than for its HVac equivalent [74].

4. Transmission distance is not limited by stability

Due to voltage stability reasons, the power flow between two nodes connected via a HVac transmission line is limited [37]. Figure 7.4 shows a single phase representation of a two-node HVac network. The left-hand side node is the sending node, where voltage is controlled at 1 per unit (pu); whereas the right-hand side node is the receiving node.

The voltage at the receiving node, v , is given by a bi-quadratic equation:

$$v^4 + [2(rp_{ac} + xq_{ac}) - e^2]v^2 + (r^2 + x^2)(p_{ac}^2 + q_{ac}^2) = 0 \quad (3.2)$$

where;

v is the voltage at the ac transmission line receiving node [pu];
 e is the voltage at the ac transmission line sending node [pu];
 r is the ac transmission line per-unit length resistance [pu/km];
 x is the ac transmission line per-unit length reactance [pu/km];
 p_{ac} is the active power at the receiving node [pu] and;
 q_{ac} is the reactive power at the receiving node [pu].

If the power factor at the receiving node is known, then substituting $q_{ac} = p_{ac} \tan \phi$ into (3.2), and rearranging it with respect to p_{ac} yields:

$$[(r^2 + x^2) \sec^2 \phi] p_{ac}^2 + [2v^2(r + x \tan \phi)] p_{ac} + (v^4 - (ev)^2) = 0 \quad (3.3)$$

Figure 3.3 shows a series of curves – known as nose curves – obtained by solving (3.3) with regard to the receiving node voltage, as a function of the transmitted active power between the two nodes for different power factors ($\cos \phi$).

The curves shown in Figure 3.3 have a point where the transmitted active power is maximum, corresponding to a maximum load angle. The maximum power is transmitted when the inflexion of $p_{ac} = f(v)$ changes, i.e. $\partial p_{ac} / \partial v = 0$, while all the other parameters – e, x, r, ϕ – are held constant.

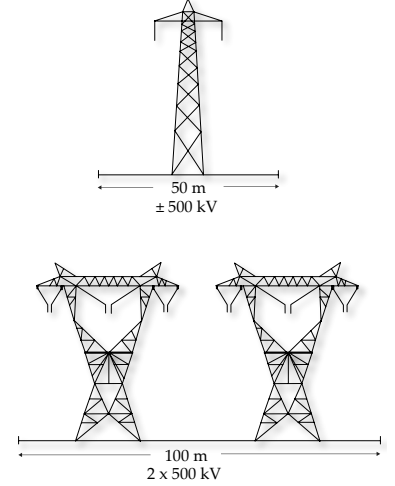


Figure 3.1: ROW Comparison between HVac and HVdc lines [73].

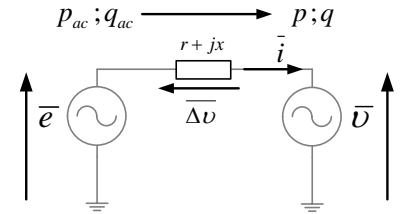
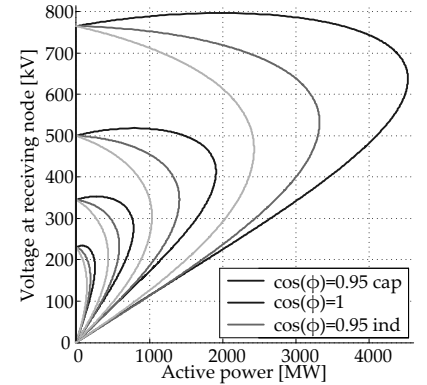
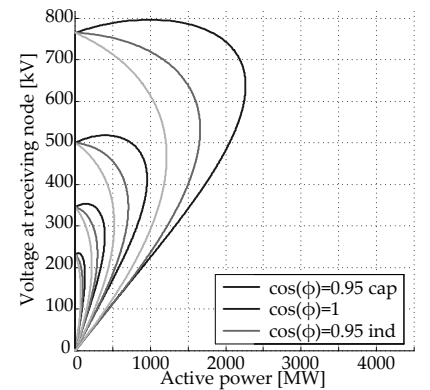


Figure 3.2: Single phase representation of a two-node HVac network.



(a) Transmission Distance = 250 km



(b) Transmission Distance = 500 km

Figure 3.3: Maximum transmittable power using HVac transmission.

Figure 3.4: Maximum transmittable power as a function of the line SIL and transmission voltage for a HVac line where the receiving end has an unity power factor ($\cos\phi = 1$).

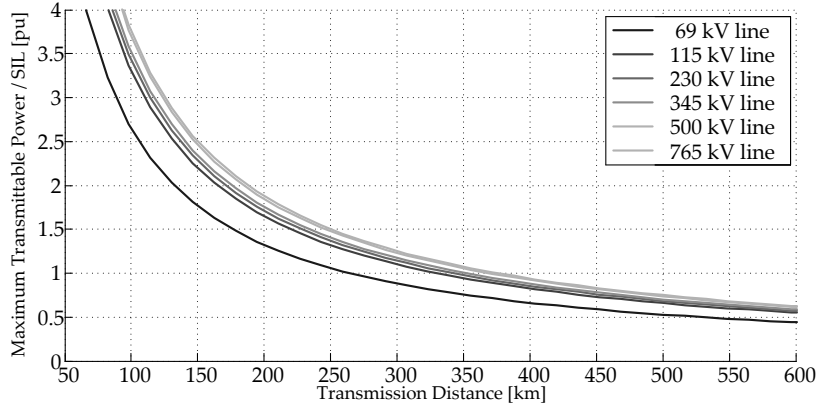


Table 3.1: Typical parameters of HVac transmission lines [75].

Voltage [kV]	R [Ω/km]	X [Ω/km]	X_c [$k\Omega\text{-km}$]	Z_s [Ω]	SIL [MW]
69	0.1740	0.441	267.1	343.1	14
115	0.0734	0.449	271.9	349.6	38
230	0.0622	0.483	293.3	376.0	141
345	0.0373	0.367	222.0	285.3	417
500	0.0174	0.337	204.3	262.6	952
765	0.0118	0.341	206.0	264.8	2210

The HVac line surge impedance, Z_s , is obtained as:

$$Z_s = \sqrt{XX_c} = \sqrt{l/c}$$

where;

X is the ac transmission line per-unit length inductive reactance [Ω/km];

X_c is the ac transmission line per-unit length capacitive reactance [Ω/km];

l is the ac transmission line per-unit length inductance [H/km] and;

c is the ac transmission line per-unit length capacitance [F/km].

whereas the surge impedance loading is calculated as:

$$SIL = E_L^2 / Z_s$$

where;

E_L is the transmission system line voltage [V].

Figure 3.4 shows the maximum transmittable power of typical HVac transmission lines as a function of the line surge impedance loading (SIL) and transmission distance, considering the receiving node to have unity power factor [75]. The line parameters used to perform the calculations are given in Table 3.1.

With HVac transmission, to transfer power above the line SIL, the transmission distance has to be kept short and the power factor has to be kept as capacitive as possible, for instance by adding shunt capacitors along the line. To transmit power below the line SIL, shunt inductances might be needed. In long-distant overhead HVac lines the stability limits are more critical, whereas in shorter transmission lines – and also in underground and submarine cables – the thermal limits (ampacity) tend to limit the power transfer [75].

5. Higher efficiency

The initial motivation for the development of HVdc systems was the higher efficiency, as electricity transmission in dc does not suffer from the skin and proximity effects. Both effects contribute to a non-uniform current distribution in conductors carrying ac, where most of the current is found in the conductors outer layers. The results is an increased effective resistance when electricity is transported in ac rather than in dc, resulting in higher transmission losses. Figure 3.5 shows the skin effect on Partridge and Drake ACSR⁵ cables for HVac systems.

Additionally, dc lines do not require reactive power compensation since the line power factor is always unity, which also translates in

⁵ Aluminium-conductor steel-reinforced.

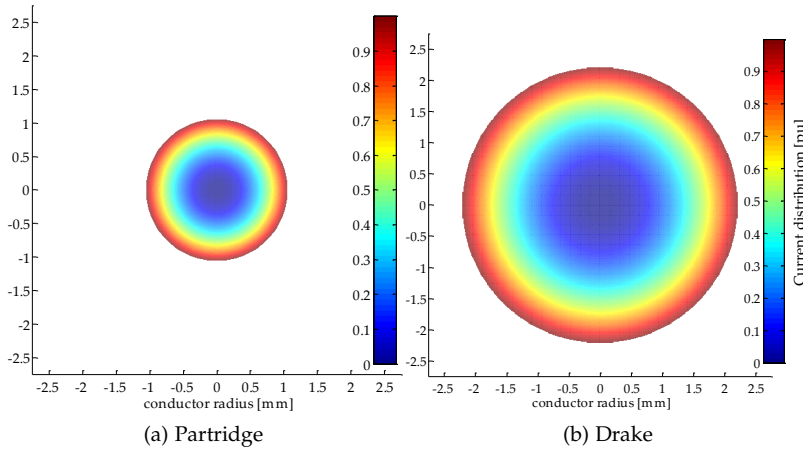


Figure 3.5: Skin effect on one conductor of high-voltage ACSR cables.

The Partridge cable is formed by 26 aluminum conductors of 2.57 mm and 7 steel conductors of 2.0 mm diameter (26x7), it has a total area of 135.2 mm^2 and can carry up to 475 A per cable. Each conductor is rated at 18.3 A.

The Drake cable is also 26x7, with aluminum conductors of 4.44 mm and steel conductors of 3.47 mm diameter, it has a total area of 403 mm^2 and can carry up to 907 A per cable. Each conductor is rated at 34.9 A [76].

lower losses if dc transmission is used.

6. Each conductor can be an independent circuit

If there is no environmental restriction to the use of ground as a return path, each HVdc conductor can be used as an independent circuit in case of a fault, which is not possible with HVac transmission systems [37,46]⁶.

7. Synchronous operation is not required

One of the main reasons to use HVdc systems is to interconnect different asynchronous ac systems, which can have the same or different frequencies, as is the case of the HVdc links between, for example: Brazil and Argentina, Garabi link; Brazil and Paraguay, Acaray link; Russia and Finland, Vyborg link; the USA and Mexico, Sharyland link; France and the UK, Cross channel link; and the Netherlands and Norway, NorNed link [41,43]. Figure 3.6 shows some of the HVdc transmission systems in Japan, famous for having both 50 and 60 Hz ac systems [77].

Additionally, as dc systems do not require a synchronous operation, they can free generators in wind, hydro and natural gas power plants to operate at their maximum efficiency speed curves, which may differ from the main grid frequency.

8. Does not contribute to short-circuit current of the ac system.

During faults in one of the ac systems connected to a HVdc transmission system, the current from the HVdc link can be controlled to zero or to a preestablished value. Hence, HVdc systems do not contribute to the short-circuit current during an ac system fault [32,46].

9. Less problems with resonances.

In HVac systems, there are unexpected voltage rises due to resonances between the transmission line impedance, transformers and, capacitors and reactor banks used to compensate the ac line power

⁶ see Figure 2.32 in Section 2.4.

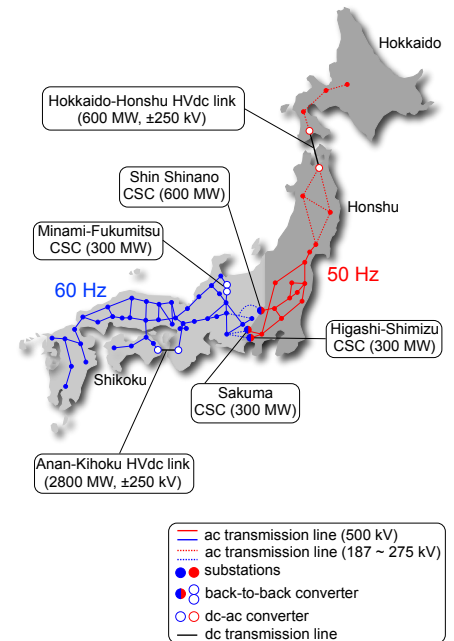


Figure 3.6: HVdc projects in Japan where both 50 Hz and 60 Hz power systems coexist [77].

factor. There are four main categories of resonances in HVac systems: near resonance, harmonic resonance, ferroresonance and sub-synchronous resonance [78]. In HVdc systems there are less resonance related voltage surges as cables used for HVdc transmission have resonance peaks in high-frequencies (over 10 kHz) and the harmonic content on the dc side can be easily mitigated via low-pass filters.

3.2 Transmission system selection for offshore wind farms

The selection of which transmission technology to use – HVac or HVdc – depends on the technical aspects of each project. For the connection of an offshore wind farm, it is usually based on efficiency and economic viability calculations, where the two most important parameters to consider are the offshore wind farm distance to shore and its installed capacity.

To cross long distances by means of submarine cables the HVdc solution starts to be preferable in comparison with traditional HVac lines, since the latter has higher losses (due to skin effect and leakage capacitive current), and will demand additional equipment to provide reactive power compensation [79]. Hence, selecting HVac transmission for the connection of offshore wind farms has the following disadvantages [80]:

- Long submarine ac cables produce large amounts of capacitive reactive power;
- There is need to provide reactive power compensation (from a STATCOM or a Static VAR compensator (SVC));
- Transmission capability decreases sharply as a function of distance given the reactive power production and high dielectric losses through the cable⁷.

Hence, in addition to the load current, ac cables must carry the reactive current generated by the cable distributed capacitance, which impairs the transmittable active power through the cable. The total active power which can be transmitted using an ac cable can be calculated as:

$$P_{ac} = \sqrt{S_n^2 - Q_{ac}^2} - 3rI_{ac}^2d \quad (3.4)$$

where,

P_{ac} is the ac cable transmittable active power [W];

S_n is the ac cable rated apparent power [VA];

Q_{ac} is the ac cable generated reactive power [VAR];

r is the ac cable resistance per phase per unit-length [Ω/km];

I_{ac} is the ac cable rated current [A] and;

d is the transmission distance [km].

⁷ Nevertheless, in comparison with HVdc systems, HVac transmission systems have a wider dissemination since they are more straightforward to install and present a lower footprint when installed offshore [46].

Hitherto, the majority of the operational offshore wind farms in Europe have been connected through a HVac transmission system to shore. The main reasons for choosing this technology are given the fact that currently only a few offshore wind farms have power ratings above 200 MW and almost all of them are located within less than 30 km to shore [11].

Assuming a constant voltage and current throughout the ac cable, its total generated reactive power per is:

$$Q_{ac} = Q_c - Q_l = 3\omega c E^2 d - 3\omega l I_{ac}^2 d \quad (3.5)$$

where;

Q_c is the ac cable capacitive reactive power [VAr];

Q_l is the ac cable inductive reactive power [VAr];

ω is the ac network angular frequency [rad/s];

c is the cable capacitance per phase per unit-length [F/km] and;

l is the cable inductance per phase per unit-length [H/km].

On the other hand, dc cables do not suffer from leakage current of capacitive nature and thus, in steady state, the electricity transmission is only limited by the cable resistance, i.e. the Joule losses. The total active power which can be transmitted using a dc cable can be calculated as:

$$P_{dc} = P_n - 2r_{dc} I_{dc}^2 d \quad (3.6)$$

where;

P_{dc} is the dc cable transmittable active power [W];

P_n is the dc cable rated power [W];

r_{dc} is the dc cable resistance per phase per unit-length [Ω/km] and;

I_{dc} is the dc cable rated current [A].

Table 3.2 provides typical parameters for HVac and HVdc submarine transmission cables [40,81], whereas Figure 3.7 depicts the maximum transmittable power in relationship with the transmission distance in per unit of the cable power rating.

— : data not available

* The current rating of a cable (also known as its ampacity) depends on several factors, such as the rated power, voltage, length, isolation method, burying depth, soil type and conductor type.

Table 3.2: Typical parameters of HVac and HVdc submarine cables [40,81].

Cable type	HVac						HVdc					
Cable cross section [mm^2]	630		1000				300		1200			
Resistance per phase [$m\Omega/km$]	28.3		17.6				60.1		15.1			
Current Rating (Copper) [A]*	715		1065	825		1290	797		1791			
Rated Voltage [kV]	132	220	400	132	220	400	± 80	± 150	± 320	± 80	± 150	± 320
Rated Power [MVA or MW]	163	272	737	189	314	894	128	239	510	287	537	1146
Capacitance per phase [nF/km]	209	151	130	238	177	160	—	—	—	—	—	—
Inductance per phase [mH/km]	0.37	0.41	1.40	0.35	0.38	1.35	—	—	—	—	—	—
Reactive Power @50 km [%]	29.5	38.5	34.1	28.6	38.9	33.1	0	0	0	0	0	0
Available Power @50 km [%]	95.5	92.3	94.0	95.8	92.1	94.3	94.1	95.5	95.3	96.0	95.3	96.0
Reactive Power @100 km [%]	59.1	77.0	68.3	57.2	77.9	66.3	0	0	0	0	0	0
Available Power @100 km [%]	80.7	63.8	73.1	82.0	62.8	74.9	91.2	94.2	93.7	95.2	93.7	95.2

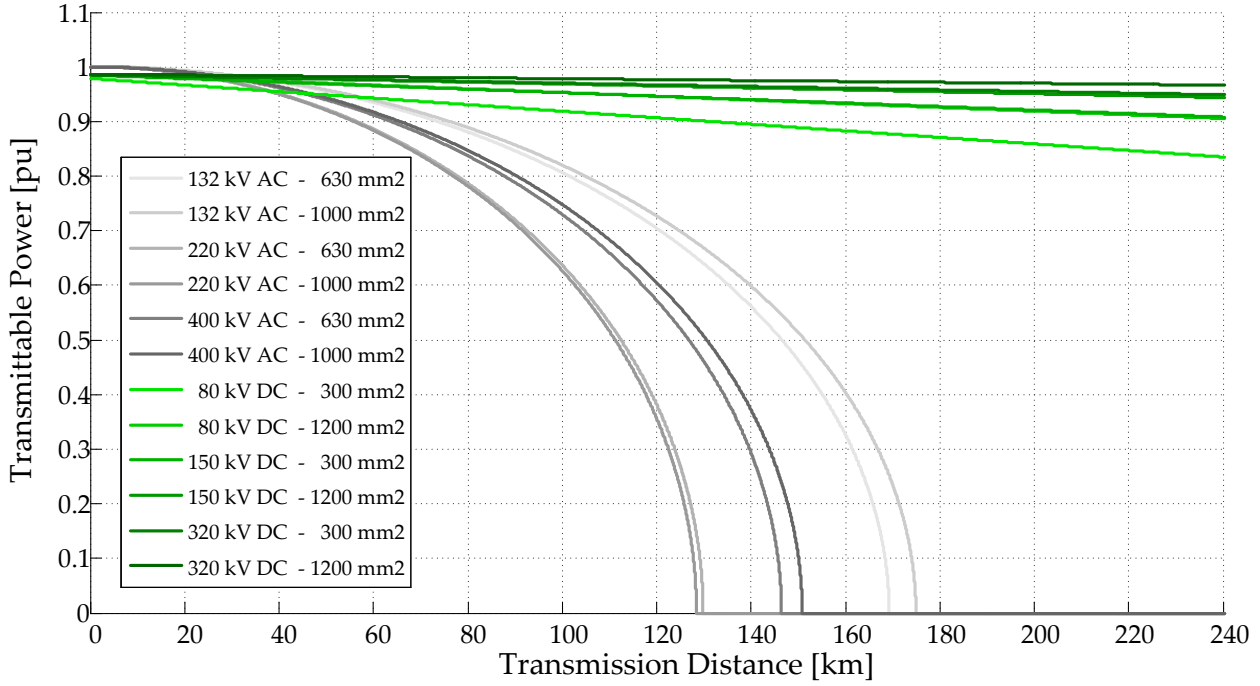


Figure 3.7: Maximum transferrable power as a function of transmission distance for ac and dc submarine cables.

Surprisingly, between the ac cables, the 220 kV cables have the lowest maximum the transmission distance, while the 132 kV cables have the best performance. However, the values shown in Table 3.2 are only indicative, and the ac cables maximum transmission length changes for different cable parameters [40,81]. Even so, after distances greater than circa 80 km, HVdc transmission systems are currently a better option for the connection of offshore wind farms [82].

Meanwhile, there are efforts to improve the voltage rating of submarine underground ac cables to voltages higher than 400 kV. While it is true that increasing the voltage augments the ac cable rated power, the cable reactive power generation grows with the square of the voltage – as shown in (3.5) – thus the problem of high charging current losses persists.

As future planned offshore wind farms tend to be built further away from the shore, and become ever bigger in size, HVdc transmission becomes a better option. Thus, it will be increasingly difficult to keep using HVac transmission systems for the connection of far and large offshore wind farms due to the need to provide reactive power compensation, which increases the transmission system costs.

Figure 3.8 shows a comparison between the costs for a HVac and a HVdc transmission system. When the transmission distances and power involved are high, HVdc transmission systems becomes justifiable, i.e.: they present a higher initial capital expenditure, due to the converter stations; but they are cheaper in the long run due to the lower operational expenditure obtained from lower transmission losses.

Several studies have shown that for large offshore wind farms

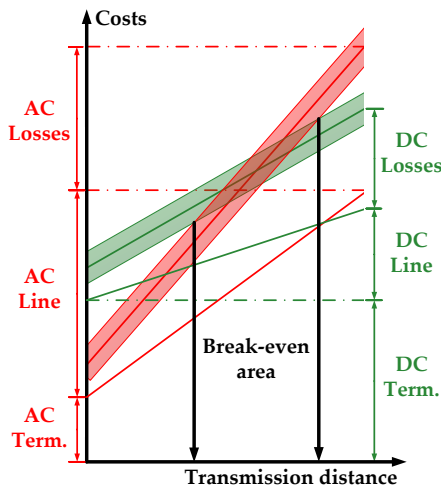


Figure 3.8: Cost Comparison between HVac and HVdc transmission systems.

Project Name	Country	Project Connection	Power [MVA]	Transmission Technology	Transmission Voltage [kV]	Cable Length [km]	Year
Utgrunden	Sweden	OWF	10	MVac	20	8	2000
Middelgrunden	Denmark	OWF	40	MVac	30	3	2001
Horns Rev	Denmark	OWF	160	HVac	150	15	2002
Scroby Sands	England	OWF	76	MVac	33	-	2004
Barrow	England	OWF	90	HVac	132	7	2006
Alpha Ventus	Germany	OWF	80	HVac	110	45	2009
Robin Rigg	Scotland	OWF	180	HVac	132	12	2009
Gotland	Sweden	Tie-in	80	HVdc	± 80	70	1999
Tjaereborg	Denmark	OWF	7.2	MVdc	± 9	4.3	2000
Troll A	Norway	Oil Rig	82	MVdc	± 60	67	2005
Estlink	Estonia / Finland	Tie-in	350	HVdc	± 150	105	2006
Borkum West II	Germany	OWF	400	HVdc	± 150	200	2009
BorWin1	Germany	OWF	400	HVdc	± 150	125	2012
HelWin1	Germany	OWF	576	HVdc	± 250	75	2014
BorWin2	Germany	OWF	800	HVdc	± 300	125	2014
SylWin1	Germany	OWF	864	HVdc	± 320	85	2014

Table 3.4: Offshore wind farms and other offshore projects

(above 500 MW) and for long submarine distances (above 70 km), HVdc transmission systems are, both economically and technically, more convenient than using HVac systems for the transmission of the offshore generated electricity (see Table 3.4) [82–84].

3.3 MTdc Network Architecture & System Integration

The North Sea Transnational Grid project, with its intention of inter-connecting around 70 GW of offshore wind power between several countries in the North Sea up to 2030, is a very ambitious initiative. The NSTG will have to organically grow with time from its initial phase; inherently simple with few terminals, to its desired final form, expected to have a more complex meshed topology [85].

For projects of such dimension and complexity, choosing the most suitable construction architecture right from the start is extremely important. It is possible to define system architecture in several ways. One possible way is to verify the way on which the operative elements of a system are arranged into blocks and how these blocks interact. Ulrich defines system architecture as [86]:

“System architecture is the scheme by which the function of a system is allocated to physical components”.

Hence, system architecture is related to the way how components inside a system interact and interface with each other. Usually two distinctive types of system architecture are recognised: integral and modular system architectures.

A system employing an integrated architecture is usually designed to maximise a particular performance measure. Modifications to one feature or component are not straightforward and may affect the design of the whole system. In addition, functionalities inside the system may be distributed across multiple components and eventually boundaries between these components may be difficult to identify or may not even exist.

⁸ Analysing the complexity involved in the development of a system such as the NSTG, it is somehow immediate that an integrated architecture is evidently not the most convenient choice for the construction and expansion of the system. Modifications to features and/or components are likely to occur regularly during the initial and growing phases. Nevertheless, there should be little redesign of the whole system given technical difficulties and large costs involved.

For systems as the NSTG, one potential solution is to adopt instead, from early stages of development, a modular architecture approach⁸. A module is usually defined as a part of a system that is not so strongly coupled to other elements inside the system. According to Baldwin [87]:

“Modularity is the practice of building complex systems or processes from smaller subsystems that can be designed independently yet function together as a whole”.

In a modular system, each module may be designed independently from each other, which allows changes to be made to one module without generally affecting the other modules. Therefore, it becomes crucial to be able to distinguish clearly which are the objectives and primary functions of each module, and what are the possible interactions between them. The task of establishing the modules functionalities inside the system can be accomplished by design hierarchy and standardisation.

Design Hierarchy and Standardisation

Design hierarchy and standardisation will be two important concepts inside the NSTG since more than one stakeholder are needed for developing and funding the whole system [85].

In the modularisation process of a complex system, the first task is to establish which are the parts of the system that can be considered modules or subsystems. Inside the NSTG, the wind farms, HVdc converter stations, dc transmission cables, potential protective and control systems naturally constitute the basic building blocks or modules.

Next, the design engineers establish a set of design rules which accounts for:

- System components: what are the system’s modules and their roles;
- Interfaces: description of how the modules inside the system are connected and interact with each other;
- Test procedures: procedures that set the performance levels of a certain subsystem and allow for comparison between different versions of the same subsystem.

In a modular system, the set of design rules is known as design hierarchy and it is composed of levels. The global design rules are at the highest level. At the next level are the modules interfaces, system integration and communication.

Finally, at the lower levels, there are the design parameters that concern only the modules themselves. Figure 3.9 shows an example of how a system design hierarchy for the NSTG could resemble [85].

Offshore dc networks will require rules in a similar way in which ac grids operate with regard to the transmission system operator (TSO) grid code. During early development stages, the design rules

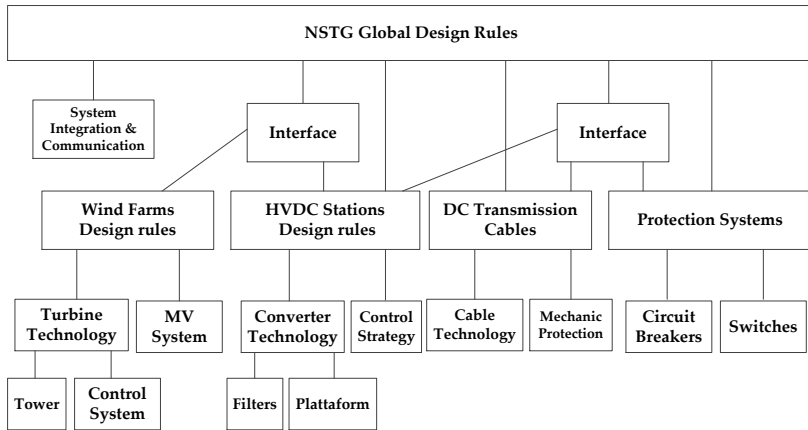


Figure 3.9: Possible design hierarchy for the NSTG system with four modules.

From the system design hierarchy displayed in Figure 3.9, it is possible to see different levels of information access. In this case for example, the global design rules are directly visible to the HVdc Stations and to the Protection System modules but indirectly visible to Wind Farm modules.

This means that Wind Farm system engineers need only to take into account their local interface, i.e. the HVdc Stations modules, whilst engineers working on the latter have to take the system global design rules into consideration in addition to their local interfaces.

might appear simple or not complete. However, as the characteristics of the NSTG and the modules inside it become better understood, the design rules will also tend to be further developed [85]⁹.

The NSTG global design rules, i.e. the design parameters in the top level of the diagram, must be established first due to the fact that they directly affect all the modules that are part of the system. Examples of global design rules inside the NSTG could include, but are not limited to, the offshore grid direct voltage level – nominal, steady-state and transient range – the size and topology of each HVdc station, multi-terminal dc protection philosophy, multi-terminal dc control and the power transfer capability of dc cables.

The crucial point is that changes made to the global design rules will have large implications on all modules, and are thus expected to be expensive and difficult to perform.

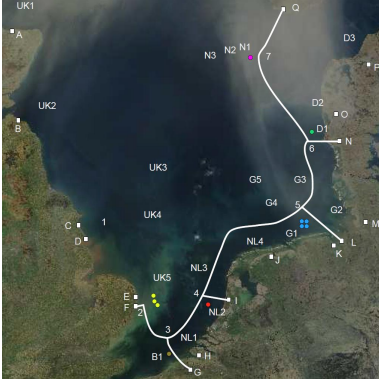
For instance, Siemens has been awarded three projects for the connection of offshore wind farms in German waters. However, all three projects will have different direct voltage levels – Borwin2 (± 300 kV), HelWin1 (± 250 kV) and SylWin1 (± 320 kV) – even though they are located relatively close to one another [88]. Since dc-dc converters in the gigawatt range are currently not available, the different direct voltage levels will make the interconnection of these offshore wind farms to a future North Sea Transnational Grid much more challenging and expensive.

As shown in Figure 3.9, changing the direct voltage level of the MTdc system would be one of these far reaching modifications that are bound to be costly and technically difficult [49,71].

Thus, once the dc level inside the NSTG system is established, there will be very little room to change it. In comparison, modifications of features inside a module in the lower levels of the diagram have limited extension and should be easier and cheaper to perform [87].

System engineers must carefully establish and take global design rules into consideration before systems such as the North Sea Transnational Grid can be built and developed. Proper development of the system global design rules can lead to dc grid code standards

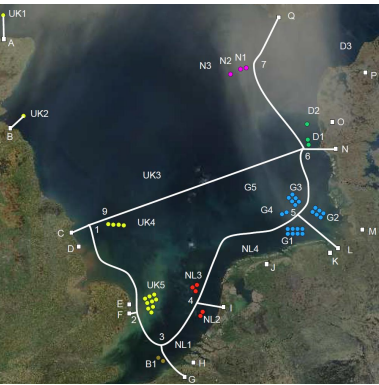
⁹ The role of system designer could be performed by the North Seas Countries Offshore Grid Initiative which could establish the design rules for the North Sea Transnational Grid.



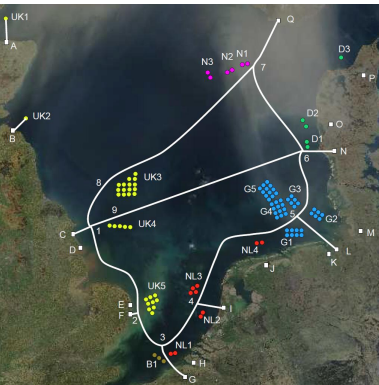
(a) Phase 1



(b) Phase 3



(c) Phase 5



(d) Phase 10

Figure 3.10: Some of the MTdc network development phases foreseen by the NSTG project [89].

which could reduce costs by having a single common design, allowing systems to be built incrementally and by different suppliers, thus supporting incremental investment plans.

In this way, a large pan-European offshore dc network would be developed “organically”. First by the construction of a few small independent dc grids with four to six terminals that, in a later stage, would be combined to form together a larger offshore network with a more complex topology, such as a meshed multi-terminal dc network. Figure 3.10 represents the organic development of the offshore transnational grid according to the North Sea Transnational Grid project [89].

3.4 Load Flow in MTdc Networks

Performing dynamic simulations for complex MTdc networks, as the ones shown in Figure 3.10, is difficult and time consuming, thus, an initial approach to study the effect of global design rules is to start with a load flow analysis. Moreover, load flow tools allow for flow-based market simulations, wind integration cost-benefit analysis, design of high-level control strategies and n-1 security assessments.

To derive the dc load flow equations, it is possible to start with from the classic ac load flow. To solve the ac load flow, the iteration process can be written as:

$$\begin{cases} \mathbf{x}(k+1) = \mathbf{x}(k) + \Delta\mathbf{x}(k) \\ \Delta\mathbf{x}(k) = -\mathbf{J}(k)^{-1} \cdot \mathbf{g}(\mathbf{x}(k)) \end{cases} \quad (3.7)$$

where;

\mathbf{x} is the state variable vector;

\mathbf{J} is the Jacobian matrix and;

\mathbf{g} is the mismatch vector.

The state variables are the node phase angles and nodal voltages, i.e. $\mathbf{x} = [\delta_1, \dots, \delta_{N-1}, V_1, \dots, V_{N-1}]^T$.

The mismatch vector $\mathbf{g}(\mathbf{x}(k)) = [g_{P_1}, \dots, g_{P_{N-1}}, g_{Q_1}, \dots, g_{Q_{N-1}}]^T$, contains the load flow equations, which are written as:

$$\begin{cases} g_{P_i} = P_{G_i} - P_{L_i} - \sum_{j=1}^N V_i V_j Y_{ij} \cos(\delta_i - \delta_j - \theta_{ij}) \\ g_{Q_i} = Q_{G_i} - Q_{L_i} - \sum_{j=1}^N V_i V_j Y_{ij} \sin(\delta_i - \delta_j - \theta_{ij}) \end{cases} \quad (3.8)$$

where;

g_{P_i} is the active power mismatch at node i [W];

g_{Q_i} is the reactive power mismatch at node i [VAr];

P_{G_i} is the active power generation at node i [W];

P_{L_i} is the active power consumption (load) at node i [W];

Q_{G_i} is the reactive power consumption at node i [VAr];

Q_{L_i} is the reactive power consumption (load) at node i [VAr];

V_i is the system voltage at node i [V];

δ_i is phase angle at node i [rad];

Y_{ij} is the admittance matrix value at position ij [S] and;

θ_{ij} is the admittance matrix angle at position ij [rad].

Since in dc networks it does not make sense to talk about phase angles, the state variables are simplified, i.e.:

$$\mathbf{x} = \mathbf{V}_{dc} = [V_{dc1}, \dots, V_{dcN-1}]^T \quad (3.9)$$

where;

\mathbf{V}_{dc} is the MTdc network voltage vector [V] and;

V_{dc1} is the MTdc network voltage at node i [V].

The vector that holds the mismatch equation is also simplified, since there is no need to write equations for the reactive power flowing in dc networks, thus:

$$\mathbf{g}_p(\mathbf{V}_{dc}(k)) = [g_{P1}, \dots, g_{PN-1}]^T \quad (3.10)$$

where;

\mathbf{g}_p is the active power mismatch vector [W].

Finally, during steady state, only the resistive part of the dc transmission cables plays a role. The load flow equations then become:

$$g_{P_i} = P_{Gi} - P_{Li} - \sum_{j \neq i} V_{dc1} V_{dcj} Y_{ij} - Y_{ii} V_{dc1}^2 \quad (3.11)$$

The next step is to calculate the dc Jacobian matrix, defined as the variation of the mismatch equations with respect to the state variables:

$$\left\{ \begin{aligned} \mathbf{J}(\mathbf{V}_{dc}(k)) = \frac{\partial \mathbf{g}_p}{\partial \mathbf{V}_{dc}} &= \begin{pmatrix} \frac{\partial g_{P1}}{\partial V_{dc1}} & \dots & \frac{\partial g_{P1}}{\partial V_{dcN-1}} \\ \vdots & \ddots & \vdots \\ \frac{\partial g_{PN-1}}{\partial V_{dc1}} & \dots & \frac{\partial g_{PN-1}}{\partial V_{dcN-1}} \end{pmatrix} \\ \frac{\partial g_{P_i}}{\partial V_{dc1}} &= \begin{cases} -Y_{ik} V_{dc1} & \text{for } k \neq i \\ -\sum_{j \neq i} V_{dcj} Y_{ij} - 2Y_{ii} V_{dc1} & \text{for } k = i \end{cases} \end{aligned} \right. \quad (3.12)$$

After updating the dc Jacobian matrix, the voltage difference between two load flow iterations, $\Delta \mathbf{V}_{dc}(k)$, can be written as:

$$\Delta \mathbf{V}_{dc}(k) = -\mathbf{J}(\mathbf{V}_{dc}(k))^{-1} \cdot \mathbf{g}_p(\mathbf{V}_{dc}(k)) \quad (3.13)$$

Finally, the direct voltages are updated according to (3.7):

$$\mathbf{V}_{dc}(k+1) = \mathbf{V}_{dc}(k) + \Delta \mathbf{V}_{dc}(k) \quad (3.14)$$

In the dc load flow, the MTdc network admittance matrix, \mathbf{Y} , can be calculated as the product of its incidence matrix, \mathbf{I}_M , and its primitive admittance matrix, \mathbf{Y}_p ¹⁰:

¹⁰ If L is the number of lines in the system and N is the number of nodes (buses), the dc system bus matrix, \mathbf{Y} , is a $N \times N$ matrix; the primitive admittance matrix \mathbf{Y}_p is an $L \times L$ matrix; and the incidence matrix \mathbf{I}_M is an $L \times N$ matrix.

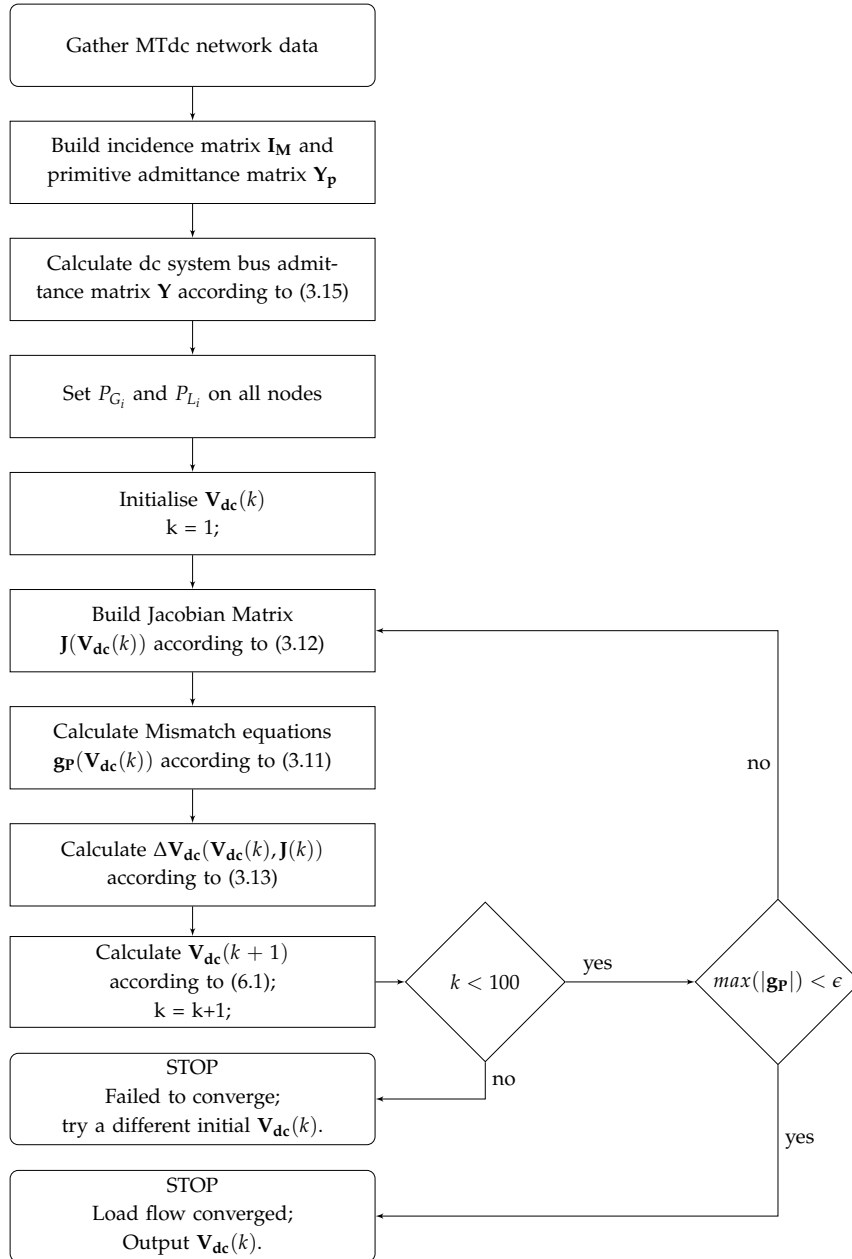
$$\begin{cases} \mathbf{Y} = (\mathbf{I}_M)^T \cdot \mathbf{Y}_P \cdot \mathbf{I}_M \\ Y_{p_{ii}} = \frac{1}{R_{dci}} \\ Y_{p_{ij}} = 0 \end{cases} \quad (3.15)$$

where;

R_{dci} is the resistance of MTdc network line i [Ω].

Figure 3.11 shows the flowchart of the developed dc load flow algorithm which uses the Newton-Raphson method to solve the non-linear problem.

Figure 3.11: Flowchart of the dc load flow algorithm.



Example of Load Flow in MTdc Networks

To illustrate how the dc load flow algorithm works, and what insights it can give on the MTdc network operation, an example is carried out based on development stage number 3 shown in Figure 3.10 (c).

The North Sea Transnational Grid layout used in the example is shown in Figure 3.12 [85]. It contains the five European countries with the highest expected installed offshore capacity, namely UK, Denmark (DN), Germany (DE), Netherlands (NL), and Belgium (BE). This layout, already very complex, contains 19 dc nodes and 19 dc transmission lines. The most important system parameters for the load flow analysis are displayed in Table 3.5.

The unit length resistances of all the transmission lines have been assumed equal to $0.023 \Omega/\text{km}$ according to [90]. For the load flow calculations, the dc system direct voltage base is assumed to be $\pm 300 \text{ kV}$ – which is also the HVdc terminals rated voltage – and the system base power is assumed equal 1000 MVA.

Table 3.6 shows the length and size of each line in the multi-terminal dc network, whereas Table 3.7 displays information on the offshore wind farms included in the load flow calculations. The wind farms location and sizes were taken from actual offshore development plans for each participating country, although the locations displayed on the map are only approximate.

In this example, all offshore wind farms were considered to be producing 75% of their nominal power, while the countries are controlling their power onshore to match the power production from its offshore wind farms. The exception is the slack node – selected to be Germany – which is instead controlling its direct voltage at 1 pu.

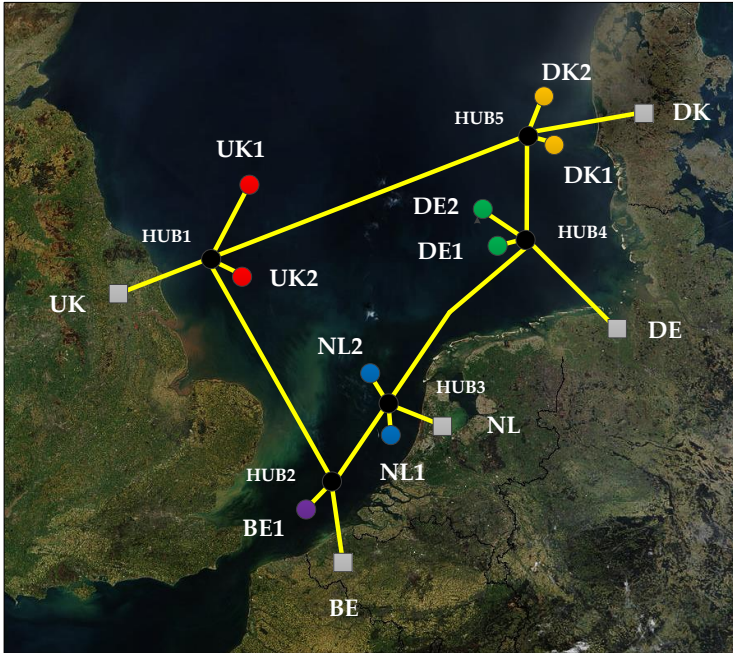


Figure 3.12: NSTG layout for the load flow study with five EU countries.

Table 3.5: MTdc system parameters in the load flow example.

Quantity	Value
Power base (S_b)	1000 MVA
Voltage base (V_b)	$\pm 300 \text{ kV}$
HVdc voltage (V_{dc})	$\pm 300 \text{ kV}$
Cable resistance (R_{dc})	$0.023 \Omega/\text{km}$

Table 3.6: MTdc network lines in the load flow example.

Line Start	Line End	Length [km]	Size [pu]
UK1	HUB1	100	3
UK2	HUB1	40	2
UK	HUB1	120	5
HUB1	HUB2	300	5
BE1	HUB2	50	1
BE	HUB2	100	1
HUB2	HUB3	120	5
NL1	HUB3	100	2
NL2	HUB3	40	1
NL	HUB3	70	3
HUB3	HUB4	250	5
DE1	HUB4	40	2
DE2	HUB4	70	2
DE	HUB4	150	4
HUB4	HUB5	120	5
DK1	HUB5	40	1
DK2	HUB5	50	1
DK	HUB5	150	2
HUB1	HUB5	380	5

Table 3.7: Offshore Wind Farms included in the load flow example.

Wind Farm	Node	Size [pu]
Doggersbank	UK1	3
Hornsea	UK2	2
Thorntonbank	BE1	1
IJmuiden	NL1	2
Eemshaven	NL2	1
Hochsee Sud	DE1	2
Hochsee Nord	DE2	2
Horns Rev	DN1	1
Ringkøbing	DN2	1

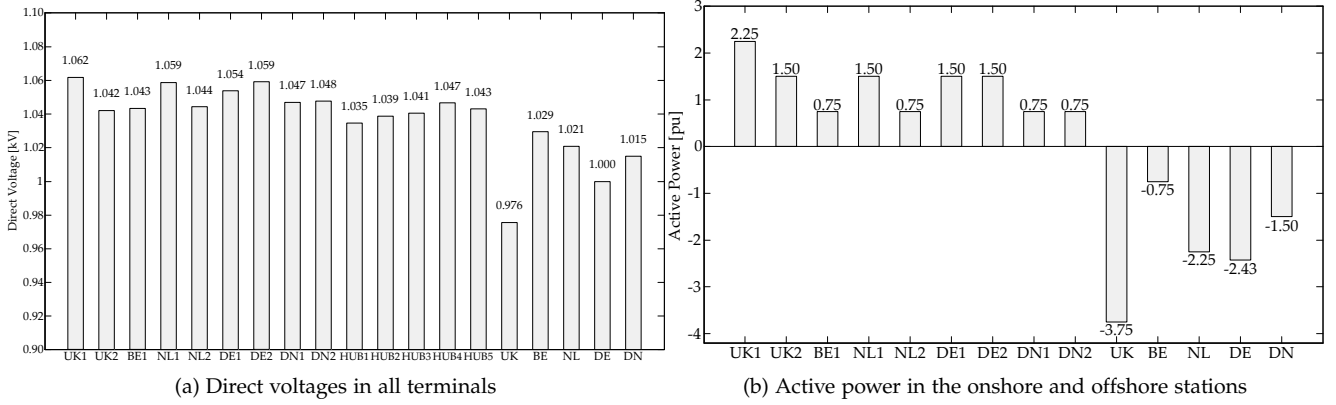


Figure 3.13: Results from the dc load flow algorithm for the NSTG studied

Figure 3.13 displays the load flow results giving the direct voltages at all the MTdc network nodes, and the active power at the onshore and offshore nodes. In this example, the highest network voltage happens at the UK1 wind farm (1.062 pu or ± 318.6 kV) since it is the highest producing node (2.25 pu or 2250 MW). On the other hand, the lowest network voltage takes place in the UK (0.976 pu or ± 318.6 kV), which is the node absorbing the most power from the MTdc network.

Since the German onshore node was chosen as the slack node in this example, its direct voltage is controlled at 1 pu. To control the direct voltage inside the MTdc network, the slack node will have to account for the transmission system losses which, in this example, amount to 0.57 pu or 570 MW¹¹.

¹¹ In the example the total offshore wind farm production amounts to 11.25 pu. Hence, in percentage of the total generated power, the MTdc network losses are equal 5.06% (disregarding converter losses).

3.5 MTdc Network Security (N-1 Analysis)

With the load flow algorithm it is possible to analyse what would be the steady-state voltages, and the power inside the MTdc network if a fault occurs in the ac side of one of the VSC-HVdc stations. When there is an ac contingency onshore, the affected node cannot exchange active power, therefore, setting its power to zero in the dc load flow algorithm allows the performance of N-1 analysis for the dc grid.

The N-1 security analysis is performed for 3 different scenarios, described in Table 3.8. In the first scenario, only Germany is working as a slack node. In the second scenario, the three countries with the highest installed capacity – UK, DE and NL – function as slack nodes. Lastly all the countries function as slack nodes¹².

In each of the three scenarios there are 6 cases: the normal load flow case and five N-1 cases, where one particular country is faulted and not anymore being able to exchange power with the MTdc network. The results are shown in Figure 3.15, where the name of the case correspond to that faulted country.

¹² Being a slack node means that the VSC-HVdc is controlling the node direct voltage at a specific value. Hence, during the load flow, these nodes (slacks) will have their direct voltages assigned to a pre-defined value of 1 pu.

Table 3.8: Scenarios for the N-1 Security Analysis.

Scenario	Slack
(a) 1 Slack	UK
(b) 3 Slacks	UK, NL & DE
(c) 5 Slacks	All countries

Scenario I

The results for the first scenario are shown in Figure 3.15 (a), where only Germany is controlling the MTdc network voltage at 1.0 pu¹³. If a fault occur in a node with a larger power transfer, such as the UK or DE, the voltage profile of several nodes, in steady-state, become well over 1.10 pu, with some node voltages in a few cases having overvoltages of more than 20%.

The highest overvoltage occurs in the UK1 offshore wind farm whose direct voltage reaches 1.24 pu when there is an ac contingency in the UK¹⁴. In this first scenario, voltages above 1.10 pu occur 45 times, which represent 39.5% of the cases.

Scenario II

The results for the second scenario are given in Figure 3.15 (b). In this case, 3 countries – UK, DE and NL –, are controlling the MTdc network voltage at 1 pu. In comparison with the first scenario, the highest overvoltage was reduced from 1.24 pu to 1.17 pu at offshore wind farm UK1.

If three nodes are working together as slacks, the number of overvoltages above 1.10 pu in the MTdc network dropped from 45 in the previous case to 13, a 28.1% reduction from 39.5% to 11.40%.

Scenario III

The results for the scenario where all the countries are working as slack nodes, with a direct voltage of 1 pu, are shown in Figure 3.15 (b). In comparison with previous results, the voltage profile within the NSTG network is much more flat with almost all the nodes having voltages levels in the range of 1.05 pu, even in the N-1 faulted cases. Moreover, the number of overvoltages above 1.10 pu dropped to 4, i.e. only 3.5% of the cases.

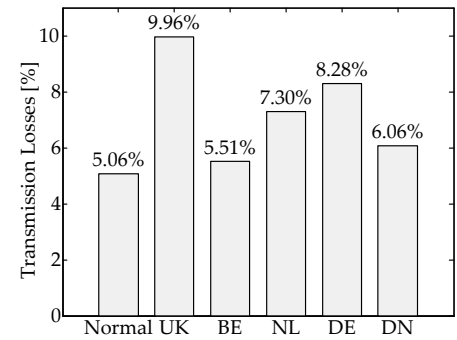
Figure 3.16 shows a box plot analysis of the three different load flow scenarios. It derives from the graphic analysis of Figure 3.15 and Figure 3.16 that as the number of countries functioning as slack nodes increases, the voltage variation at the MTdc nodes for the N-1 cases becomes lower. Nevertheless, the marginal gain of increasing the number of slacks decreases as the number of HVdc stations controlling the direct voltage increases.

System Losses

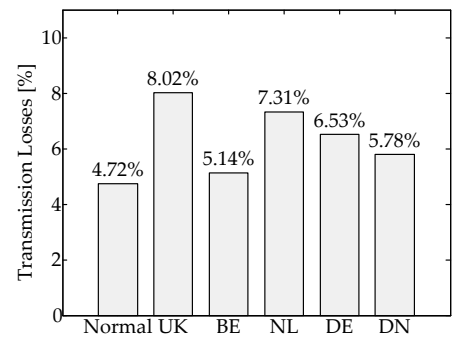
Figure 3.14 displays the losses inside the NSTG network for the different scenarios and cases. During normal operation, the losses difference is not very significant, still, the first scenario has 0.51% more losses than the last scenario. On the other hand, the difference can be quite significant for the cases where one node of the network is faulted or unavailable. In those cases the losses can be significantly different and be of economic concern when calculated over the lifetime of the MTdc network.

¹³ When the ac contingency happens in the Germany, the direct voltage control is passed momentarily to the UK, which becomes the slack node, as it is not possible to set the power at the slack node.

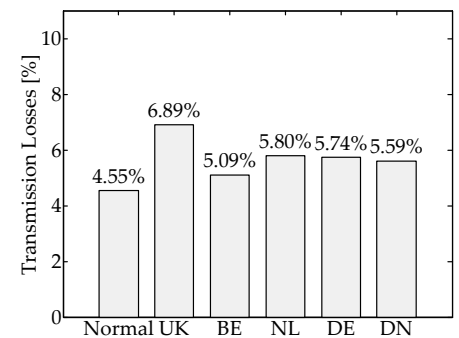
¹⁴ In case of a fault, the highest overvoltage will always be at the highest producing node in the network.



(a) Scenario I



(b) Scenario II



(c) Scenario III

Figure 3.14: MTdc network losses in the different scenarios.

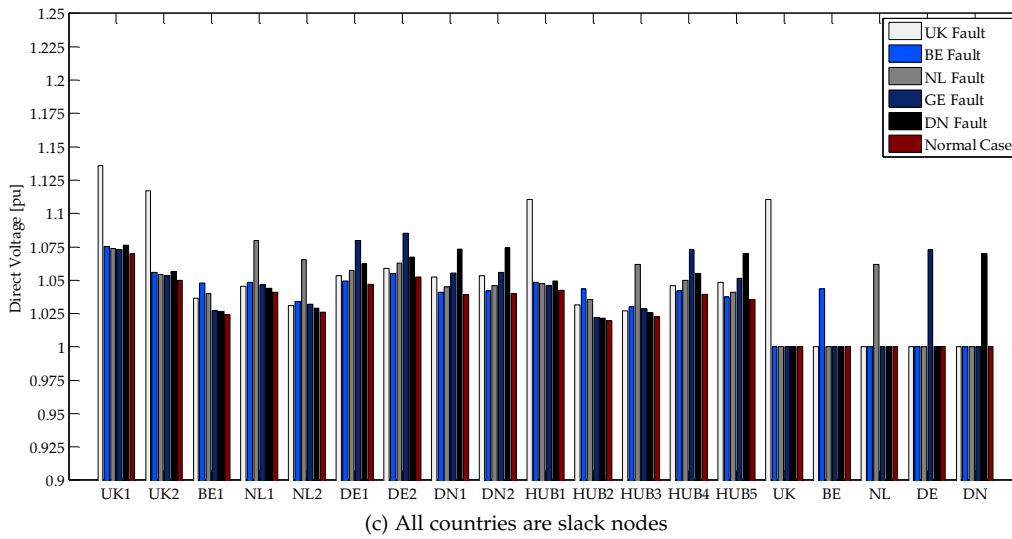
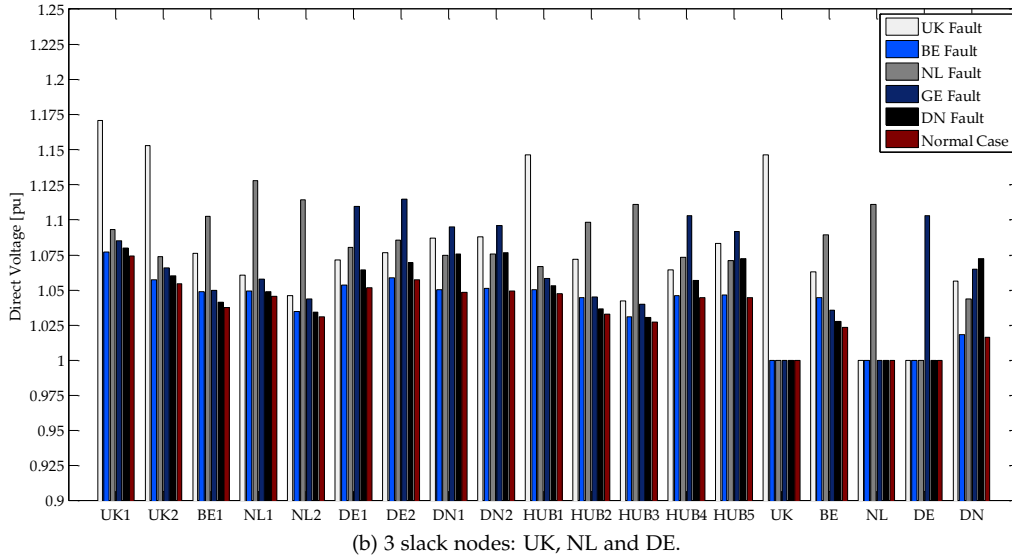
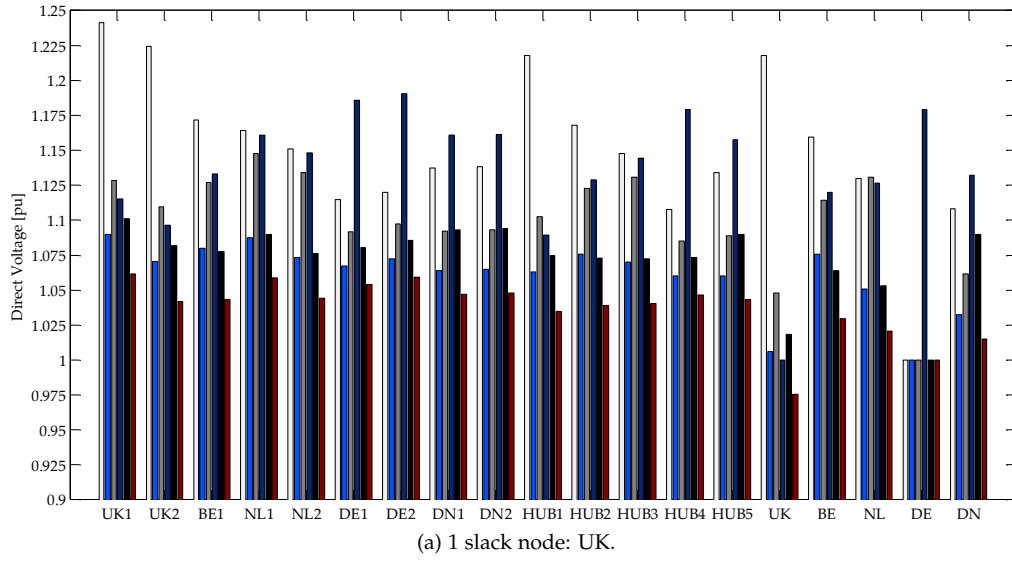


Figure 3.15: Direct voltages at the MTdc network for the different load flow scenarios.

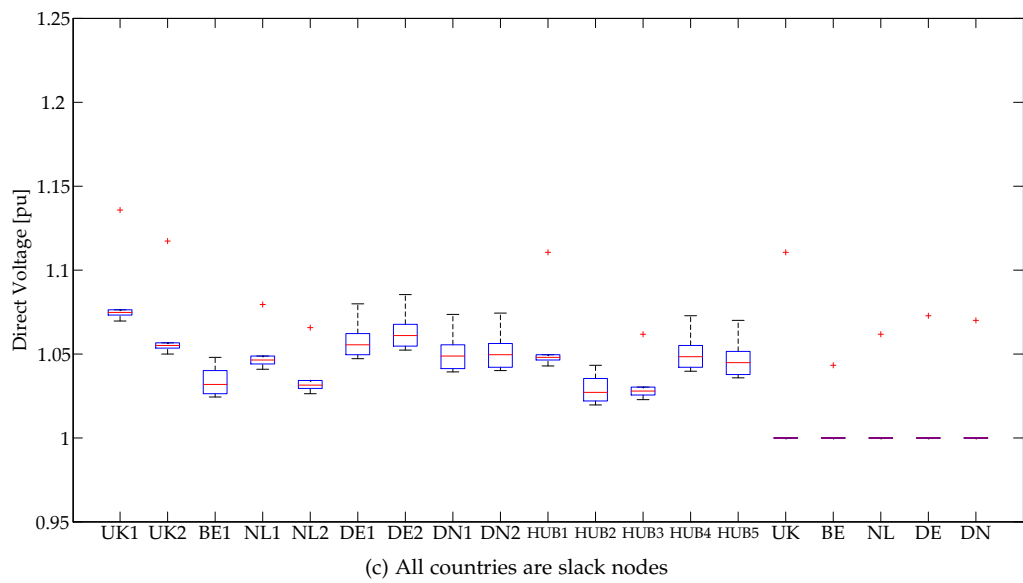
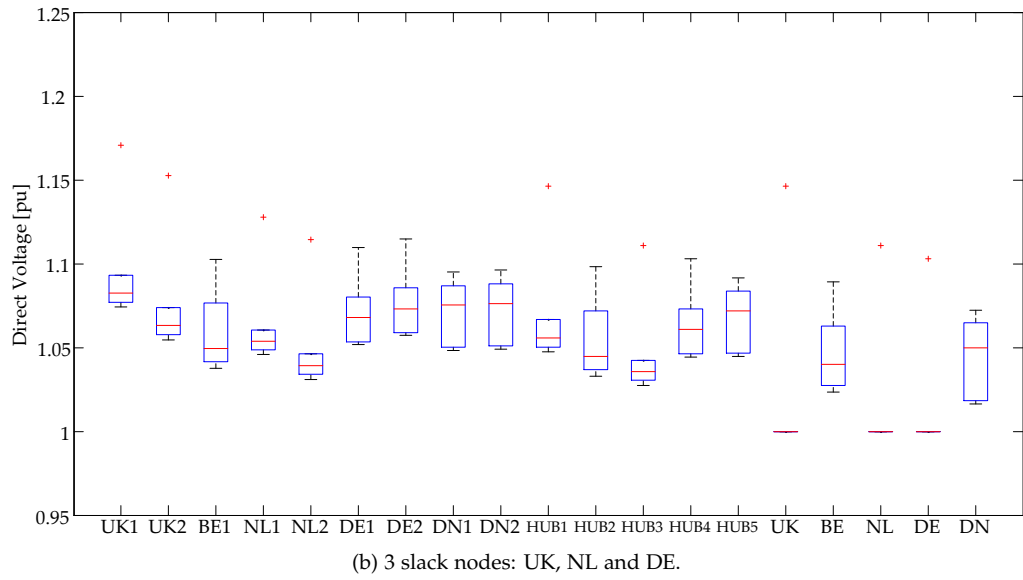
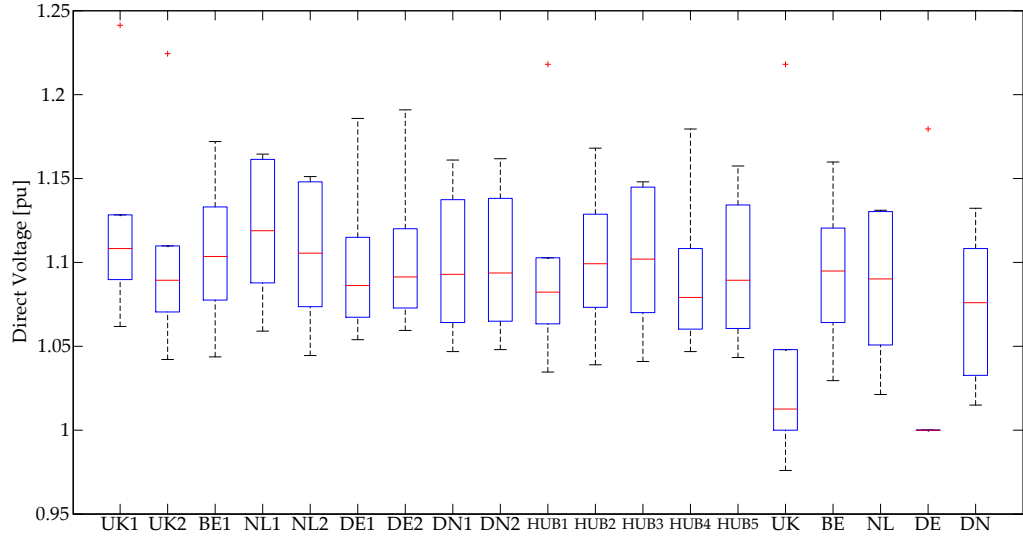


Figure 3.16: Box-plots of the direct voltages for the different load flow scenarios.

3.6 Conclusion

HVdc transmission systems are the best transmission option for offshore wind farms when distances from shore are surpassing the 100 km milestone, and the installed capacity is higher than of 500 MW, as is the case of some recent installations.

If these offshore wind farms are to be connected together in the North Sea Transnational Grid, modularity and standardisation – or offshore grid codes – will most definitely play very important roles. Multi-terminal dc networks for integration of large-scale offshore wind energy will have to grow organically with time, hence, the global design rules of such systems will have to be carefully discussed between all the involved stakeholders to avoid large changes in later development stages, which are expected to be expensive and difficult to perform.

After the system integration challenge has been solved, i.e. after the wind farms become interconnected, system designers will have to face the challenge of how to control the power flow in MTdc networks.

By means of an N-1 security analysis, using the developed dc load flow algorithm, it was shown that a situation in which more nodes are controlling its direct voltage – thus working as slack nodes – yielded better results when compared to a situation where only one node was given that task. The superiority was found regarding both N-1 contingencies scenarios and the overall losses in the transmission system.

However, to design control systems for VSC-HVdc transmission systems load flow algorithms are not enough. Therefore, dynamic models of the most important system components are needed. These dynamic models are developed next in Chapter 4.

Part III

Dynamic Analysis

4

Dynamic Modelling

Essentially, all models are wrong, but some are useful.

George Edward Pelham Box - Empirical Model-Building and
Response Surfaces

The steady-state analysis of multi-terminal dc networks was performed in Part II, where the available HVdc transmission technologies were presented in Chapter 2, and a dc load flow algorithm was developed in Chapter 3. However, dynamic models of future large offshore multi-terminal dc networks are extremely important for the assessment of overall system behaviour during normal and fault conditions, but also for control designing purposes, which is done in Chapter 5 and Chapter 6. The aim of the present chapter is to model the combined dynamic behaviour of the most important system modules inside multi-terminal dc systems. Hence, this chapter presents the dynamic models of the HVdc converters, dc network cables, offshore wind farms and ac networks.

- 4.1. Modular Model of the NSTG
- 4.2. VSC-HVdc Structure
- 4.3. VSC-HVdc Control
- 4.4. MTdc Network Model
- 4.5. Wind Farm and AC Network Models
- 4.6. Conclusion

This chapter is based on the following publications:

R. Teixeira Pinto and P. Bauer, "Modular Dynamic Models of Large Offshore Multi-Terminal DC (MTDC) Networks," in *Proceedings of the European Wind Energy Association Conference*, Brussels, Belgium, March 2011, pp. 1-10.

R. Teixeira Pinto, S. Rodrigues, P. Bauer, and J. Pierik, "Comparison of direct voltage control methods of multi-terminal DC (MTDC) networks through modular dynamic models," in *Proceedings of the 2011-14th European Conference on Power Electronics and Applications (EPE 2011)*, Birmingham, England, 30 2011-sept. 1 2011, pp. 1 -10.

4.1 Modular Model of the NSTG

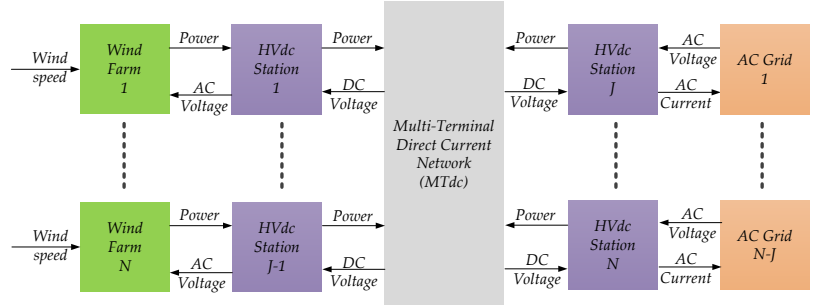
As discussed in Chapter 3, a future NSTG will be built in a modular way. Hence, it is only natural that the models used to describe the system should also be modular in nature. Dynamic models of future large offshore multi-terminal dc networks are needed for assessment of the overall system behaviour, during normal and fault conditions, to study the interactions between the offshore wind farms, the power electronic converters and other dc equipment, but also for control designing purposes.

Modular dynamic models allow highly complex systems to be divided into smaller submodules. In that way, the complete system model can easier evolve with time and even allow for having different teams working in parallel in different modules inside the same system. In addition, using modular dynamic models makes it easier to perform comparative tests of individual modules performance.

To model large offshore transnational grids, the proposed approach is to derive the equations driving the dynamic models of the most important system modules, viz.: wind farms, HVdc stations, the multi-terminal dc grid, and the interconnected onshore ac systems.

With this modular approach, it is possible to study the dynamic behaviour of MTdc networks irrespective of their topology. Figure 4.1 displays a modular representation of MTdc networks for integration of offshore wind energy with the different system components and the interaction between them.

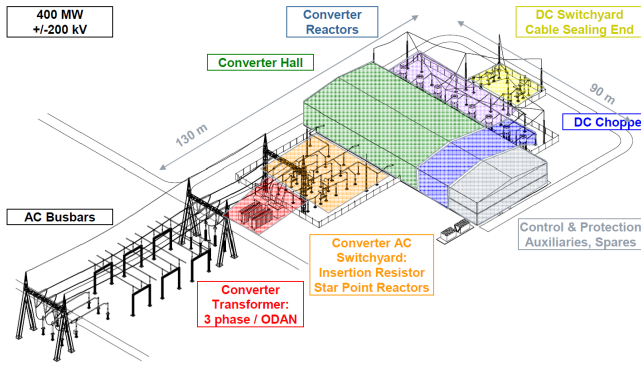
Figure 4.1: Modular representation of offshore MTdc networks.



4.2 VSC-HVdc Structure

Although the classic LCC-HVdc transmission technology is still preferred for long bulk power transmission [17], the smaller footprint and more flexible control characteristics of VSC-HVdc systems make them the most convenient choice for the connection of offshore wind farms [83,91,92].

Figure 4.2 shows the physical layout of a VSC-HVdc transmission station [93,94]. A VSC-HVdc transmission system basically consists of two converter stations, nowadays usually using a multi-level topology as discussed in Section 2.3; an ac transformer; dc-side capacitors; and a dc cable or overhead line.



(a) HVDC Plus station layout [93]



(b) Aerial view of the Shoreham converter station [94]

Figure 4.2: VSC-HVdc station layout and aerial view.

The single-line representation of a VSC-HVdc transmission station with its main components was depicted in Figure 2.15¹. Other components of a VSC transmission system scheme include: ac circuit breakers, surge arresters, ac-harmonic and radio-interference filters, transformers tap-changers, phase reactors, dc-side harmonic filters, dc chopper and braking resistor; and grounding equipment [37,46]. Some of these components are briefly discussed next.

¹ It is again shown in Figure 4.3 for convenience.

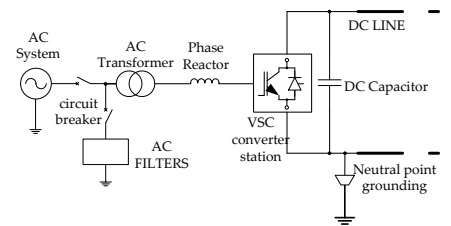


Figure 4.3: Single-line diagram of a VSC-HVdc transmission station.

AC Circuit Breaker

In a VSC-HVdc transmission system, ac circuit breakers serve a triple purpose: firstly, it connects the ac system to the converter station when, during system start-up, the dc-side capacitor is charged to the nominal voltage.

Secondly, the ac circuit breakers disconnect the converters in case of a contingency in the ac system². Lastly, voltage-source converters usually have no control means for clearing dc-side faults, differently from the classic HVdc technology. During such dc contingencies, the dc fault current will be fed through the converter free-wheeling diodes, causing the ac circuit breakers to open.

Circa two decades ago, gas-insulated switchgear (GIS) using SF₆ substituted traditional oil-based ac circuit breakers. Nowadays, the breaking time for modern GIS ac circuit breakers are in the range of circa 2 to 3 cycles of the ac frequency, i.e. 40 to 60 ms for 50 Hz ac networks [96].

The interruption processes consists of basically two steps: first, the ac circuit terminals are mechanically separated creating an electrical arc, which is then finally quenched once there is a current zero crossing. Figure 4.4 displays a HVac circuit breaker rated at 800 kV, and capable of breaking currents up to 63 kA in two ac network cycles [95].

² Voltage-source converters are usually requested to ride-through ac-side faults before being allowed to disconnect from the faulty ac system. The requirements during fault ride-through depend on the local ac network and are usually established by the entitled TSO. The grid code requirements and the fault-ride through capabilities of VSCs when inside MTdc networks is further discussed in Chapter 7, in Section 7.1 and Section 7.4.



Figure 4.4: High-voltage ac circuit breaker [95].

Transformers

The main task of the converter transformer is to adapt the ac system voltage to a level which is appropriate for the converter. If the VSC is to be operated using a sinusoidal PWM modulation strategy, with a nominal modulation index of 0.8 – which would allow the generation of higher fundamental harmonic voltages or withstanding direct voltage drops while still keeping the modulation index close to 1.0 – than the direct voltage level is selected as:

$$m_a = \frac{\sqrt{2}E}{\frac{V_{dc}}{2}} \alpha = \frac{\sqrt{2}E_L}{\sqrt{3}\frac{V_{dc}}{2}} \alpha \Rightarrow \alpha = \frac{\sqrt{3}m_a V_{dc}}{2\sqrt{2}E_L} \quad (4.1)$$

where;

m_a is the converter modulation index;

E is the ac network phase RMS voltage [V];

E_L is the ac network RMS line voltage [V];

V_{dc} is the VSC-HVdc transmission system direct voltage [V] and;

α is the transformer voltage ratio ($1 : \alpha$)³.

Other than adapting the ac system voltage and providing galvanic isolation, VSC-HVdc transformers also help with filtering the converter currents and limiting fault currents. If the secondary side of the transformer is not grounded, it also decouples the zero sequence harmonics between the HVdc converter and the ac system.

As a basic design principle, the VSC-HVdc transformer physical dimensions depend on [96]:

$$A_{cu}, A_{co} \propto \frac{S_n}{fJ\varphi_B} \quad (4.2)$$

where,

A_{cu} and A_{co} are the transformer window and core area [m²];

S_n is the transformer rated power [VA];

f is the ac network frequency [Hz];

J is the winding current density [A/m²] and;

φ_B is the peak magnetic flux [Wb].

Additionally, the following basic scaling rules apply for power system transformers [96]:

$$\begin{cases} V_o, M, P_{losses} \propto (S_n)^{3/4} \\ p_{losses} \propto (S_n)^{-1/4} \\ P_d \propto (S_n)^{1/4} \end{cases} \quad (4.3)$$

where;

V_o is the volume [m³];

M is the mass [kg];

P_{losses} are the power losses [W];

p_{losses} are the power losses relative to the rated power [pu] and;

P_d is the transformer power density [VA/kg].

³ For example, in a VSC-HVdc transmission system where the direct voltage is rated at ± 250 kV and the ac system voltage at the point-of-common coupling (PCC) is 380 kV, the transformer voltage ratio α would be equal 0.645, which means a 380/245 kV step-down transformer.

If space-vector pulse-width modulation (SVPWM) is used instead of sinusoidal PWM, the converter linear operation range increases from 1.0 to ideally $2/\sqrt{3} \approx 1.155$. Although SVPWM can be used to increase the fundamental harmonic voltage the VSC is able to generate, it increases the modulation scheme complexity. On the other hands, the drawback of using sinusoidal PWM instead, is that, for a given fundamental harmonic voltage, the direct voltage results over dimensioned.

As discussed in Section 2.4, depending on the HVdc system topology, there is no need for special transformers capable of handling direct voltages. Figure 4.5 displays HVdc transformers for LCC and VSC technology [97], the main differences are [98]:

- The insulation requirements of the transformer windings are reduced since the produced ac-side voltage has null dc offset with respect to the ground potential;
- The harmonic content in the current of a VSC-HVdc is smaller and, therefore, the transformer suffers less from the associated stresses and losses;
- There is no need for on-load tap changers for control purposes; it is provided only to optimise operation and reduce losses.

As opposed to classic HVdc, which makes use of exquisite transformer designs to build the converter bridges (e.g. 24 or 48-pulse bridges), in VSC-HVdc systems standard two-winding transformers can be used.

Considering a single-phase two-winding transformer for a HVdc application to have 1 pu weight, a single-phase three-winding unit would weight 1.6 pu, whereas a three-phase two-winding would weight 2.2 pu, and a three-phase three-winding 3.6 pu [46]. Because of the dimensions and weight of such transformers, due to transportation issues, often some heavier designs are not feasible and, for LCC-HVdc, a common compromise is given by single-phase three-winding converter transformers.

AC Filters

The role of the ac filters is to provide a sufficiently low impedance path to ground for the significant current harmonic components, reducing their effects to an acceptable level.

Designing filters for bulk transmission applications, such as LCC-HVdc or VSC-HVdc transmission systems, is a very complex task which requires elaborate analysis of steady-state and transient conditions of the HVdc system, as well as other factors including filters detuning, hardware components parametric deviations and, mostly important, possible resonance conditions. Often the design of the filter must be tailored made for each ac system that is going to be interfaced with a HVdc station [46].

A non-extensive list of the different negative effects harmonics may cause in power systems can be presented as [37]:

- Extra losses and heating in machines and capacitors;
- Overvoltages due to resonance;
- Interference, inaccuracy or instability with control systems;
- Noise on voice-frequency telephone lines.



(a) VSC-HVdc transformer



(b) Classic HVdc transformer

Figure 4.5: Example of HVdc transformers: (a) East West Interconnector Project and (b) Xi-angjiaba - Shanghai 800 kV HVdc project [97].

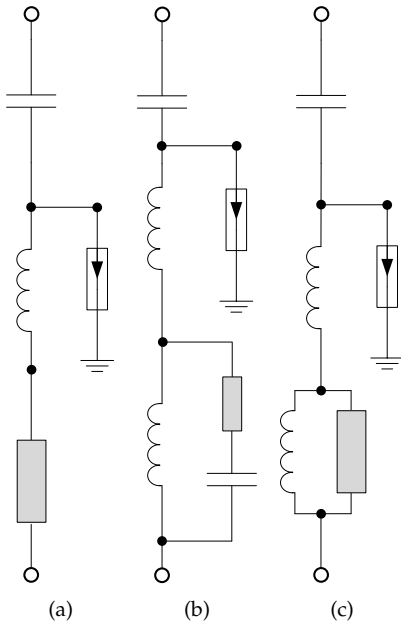


Figure 4.6: AC filters for LCC-HVdc transmission systems: (a) band-pass filter; (b) double band-pass filter and (c) high-pass filter.

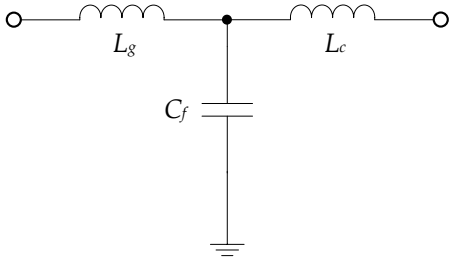


Figure 4.7: Typical LCL filter for VSC applications.



Figure 4.8: HVdc ac-side capacitor bank [100].

The sizing of harmonic filters depend directly on its reactive power capacity. For classic HVdc applications, a common requisite is the need to compensate part or the entire converter reactive power demanded at full load, or even provide overcompensation. Normally, the ac-side filters can be designed to provide from 40 to 50% of the required reactive power compensation. Given the low number of pulses – typically 12 or 24-pulses – in LCC-HVdc transmission systems, usually a combination of filters is utilised, namely: single-tuned, doubly-tuned and/or high-pass filters (see Figure 4.6) [43,98].

Filter design principles in VSC-HVdc systems are the same as in the HVdc Classic systems. However, as discussed in Section 3.5, the PWM operation in a VSC reduces the harmonic content and, therefore, the filter needs of the transmission system. Thus, ac filters in a VSC-HVdc system will be smaller and cheaper – also because there is little need to provide reactive power compensation – in comparison with the ac filters required by HVdc Classic converters.

Theoretically, for a VSC-HVdc application a high-pass filter would be sufficient, i.e. there is no need for tuned filters since the produced harmonics are in the high-frequency range. In practice, however, two or three branches of tuned filters may be necessary [96]. In addition to ac filters, a radio interference filter may be needed to prevent the electrical noise produced by the converter stations to cause radio or telecommunication disturbances [37].

To better estimate the harmonic influence on an ac network, it is not sufficient to know the filter impedance; also the network harmonic impedance must be known. Since ac networks are constantly varying, with the addition or withdraw of loads and changing system operating conditions, it is very difficult to model the grid impedance for the relevant harmonics with the aim of optimising the filter design.

As the design of a high-pass shunt filter is still quite complex, a simpler LCL filter – with or without damping, as the one shown in Figure 4.7 – is usually used for low and medium-power VSC applications [99]. The LCL-filter capacitor, C_f , is usually selected as a percentage, x , of the ac system base capacitor, C_b , by selecting the absorbed reactive power at rated conditions [96]:

$$\begin{cases} C_b = \frac{S_b}{\omega_b V_b^2} \\ C_f = x \cdot C_b \end{cases} \quad (4.4)$$

where;

S_b is the ac system base power [VA];

ω_b is the ac system base angular frequency [rad/s] and;

V_b is the ac system base voltage [V].

The filter capacitor value cannot be made too high; otherwise, there will be a reduction of power factor at rated power. Generally, a power factor decrease of 5% is set as a maximum limit [99]. For VSC-HVdc applications there is no need to compensate for 40-50% of the reactive power, thus the filter capacitors can be smaller. Indeed,

the filter capacitors reactive power are usually selected between 10 and 20% the VSC rated power. Figure 4.8 displays an ac-capacitor bank for HVdc applications [100].

Capacitors for HVac applications usually employ oil-impregnated metallised polypropylene technology and, as a basic dimensioning rule, the capacitor cost, Co , mass, M , and volume, Vo , are proportional to its reactive power, Q_f [96]:

$$Co, M, Vo \propto Q_f = 3X_f U_f^2 \quad (4.5)$$

where;

X_f is the capacitor impedance at grid frequency [Ω] and;

U_f is the filter capacitor voltage [V].

In the end, the difference in filtering needs greatly influences the total footprint of a HVdc converter station. Figure 4.9 shows, to scale, the aerial view of a HVdc Classic and a VSC-HVdc station. The Furnas HVdc Classic station from the Itaipú transmission system, in Brazil, has an area of 0.86 km² (0.86 km x 1 km) for a rated power of 3150 MW, at a direct voltage of ± 600 kV [43]. In comparison, the VSC-HVdc station in Diele – part of the BorWin1 HVdc transmission system in Germany – has an area of 0.17 km² (0.33 km x 0.50 km), for a rated power of 400 MW, at a direct voltage of ± 150 kV [101].

Phase Reactors

A phase reactor is generally installed on the ac-side of a VSC station and on the dc-side of a LCC-HVdc station. In VSC-HVdc systems the phase reactor serves the following purposes [46,98]:

- reduce the high frequency harmonic content of the ac-side converter current;
- help to avoid sudden change of polarity due to valve switching;
- allow independent control of active and reactive power;
- limit amplitude and rate-of-rise of short-circuit currents.

Independent control of active and reactive power in a VSC-HVdc is accomplished by regulating the voltage drop and current flow through the phase reactor on each converter station. Typical impedance values are in the 0.10 - 0.15 pu range [104,105]. Air coils are the most common technology for HVdc reactors, but iron core reactors are also possible. Figure 4.10 shows an 800 kV HVdc smoothing reactor, developed for UHVdc projects in China [102]; and a 350 kV phase reactor used in the Caprivi 300 MW monopole VSC-HVdc transmission system between Zambia and Namibia [103,106].

The following parameters are the main aspects which should be considered when designing a phase reactor: rated current, impedance, insulation level, overall losses, noise levels, thermal and stability dynamics [107]. A basic scaling rule for air coils is given by



(a) HVdc Classic Station (0.86 km²)



(b) VSC-HVdc Station (0.17 km²)

Figure 4.9: Aerial view (to scale from GoogleEarth) of a HVdc Classic and a VSC-HVdc converter stations.



(a) HVdc Classic smoothing reactor [102]



(b) VSC-HVdc phase reactor [103]

Figure 4.10: Air coil reactors for HVdc systems.

[96]:

$$Co, M \propto I_n \sqrt{L} \quad (4.6)$$

where;

I_n is the coil nominal current [A] and;

L is the coil inductance [H].

On the ac-network side, regardless of the specific converter technology, the VSC can always be regarded as a controllable voltage source with freedom to set the frequency, angle and amplitude of the fundamental harmonic. Figure 4.11 displays the single-line equivalent circuit of a VSC-HVdc system. As a result, the converter is modelled⁴, in the rotating direct-quadrature (dq) coordinate frame, by the following state-space equations:

$$L_T \frac{d}{dt} (\bar{i}_{dq}) = \bar{e}_{dq} - \bar{v}_{dq} - R_T \bar{i}_{dq} - j\omega L_T \bar{i}_{dq} \quad (4.7)$$

where;

\bar{i}_{dq} is the converter current in the rotating frame [A];

\bar{e}_{dq} is the ac network voltage in the rotating frame [V];

\bar{v}_{dq} is the converter voltage in the rotating frame [V];

R_T is the total resistance between the VSC and the ac grid [Ω];

L_T is the total inductance between the VSC and the ac grid [H] and;

j is the imaginary unit matrix representation⁵.

If the ac network angular frequency, ω , can be considered constant⁶, the resulting system is linear and autonomous, i.e. does not depend on time as an independent variable. However, without closed-loop current control the system given in (4.7) would be poorly damped and have a bad dynamic (under-damped) response, as will be shown in Section 4.3.

DC Capacitors

For proper operation, voltage-source converters rely on a direct voltage source controlled within stiff limits. The required energy storage on the dc-side of the converter is provided by dc capacitors, which act as a voltage source. The dc capacitors, usually placed in both ends of a VSC-HVdc link, minimise the stray inductance in the commutating loop, providing a low inductive path for the turn-off current, thus also serving as a filter for high frequency currents on the converter dc side [46].

A large dc capacitor contributes to a lower direct voltage ripple, which is inherently associated with the dc amplitude and switching frequency. On the other hand, the dc capacitors should be kept small enough to allow fast direct voltage and power flow control.

To design the dc capacitors, engineers must also consider the system transient behaviour as large power oscillations may occur between the ac and the dc side of the converter during disturbances in the ac system, such as faults or switching maneuvers, which lead to dc-side overvoltages that may stress or damage the converter valves.

⁴ Disregarding the presence of the ac filters, which are considered in a later stage.

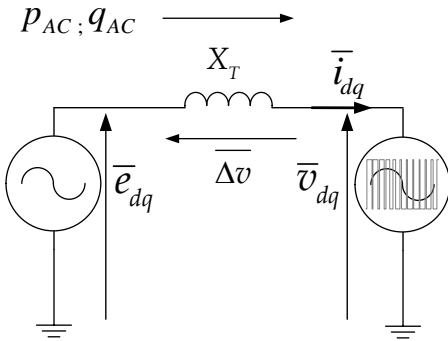


Figure 4.11: Equivalent ac-side circuit of a VSC-HVdc station.

⁵ $j = \begin{pmatrix} 0 & -1 \\ 1 & 0 \end{pmatrix}$.

⁶ A safe assumption as the grid frequency is usually tightly controlled within the 0.98 - 1.02 pu range.

Therefore, it is essential to take into consideration the transient voltage constraint of the valves when the dc capacitors are selected.

Nowadays, in contrast with ac capacitors which mostly use oil-impregnated polymers, high-voltage dc capacitors use dry polymers as dielectrics [108]. Dry metallised film capacitors (available for power applications for almost two decades) are more environmental friendly and are explosion safe as opposed to oil-impregnated capacitors [96].

Additionally, when compared to oil-impregnated, film capacitors offer twice the capacitance in half the volume, are self-healing (insulation faults are isolated internally), have a shorter production time and are simpler to install [96]. Figures 4.12 (a) and (b) show examples of dry metallised and oil-impregnated capacitors for HVdc applications [109], whereas Figure 4.12 (c) shows the valve submodule of a HVdc Maxsine, in which circa half the volume is occupied by the dc capacitor [58]. In HVdc modular multi-level converters systems, up to ten times more power capacitors are needed in comparison to two-level VSC-HVdc systems [110].

Similar to high-voltage ac capacitors, as a basic dimensioning rule, the costs, C_o , mass, M , and volume, V_o , of dc capacitors are proportional to its stored energy [96]:

$$C_o, M, V_o \propto W_c = \frac{1}{2} C_{dc} V_{dc}^2 \quad (4.8)$$

where;

W_c is the stored energy in the VSC capacitor [J].

The equivalent dc circuit of a VSC-HVdc station is usually represented by a controllable current source, acting on the VSC station equivalent capacitor, as represented in Figure 4.13. The VSC direct voltage and the power flowing into the dc network are then given by:

$$\begin{cases} W_c = \int (P_{dc} - P_L) dt \\ V_{dc} = \left(\frac{2}{C_{dc}} \cdot W_c \right)^{\frac{1}{2}} \end{cases} \quad (4.9)$$

where;

P_{dc} is the VSC active power [W] and;

P_L is the active power flowing into the MTdc grid [W].

Ultimately, the dc capacitor can be characterised by a time constant, τ , which basically determines the VSC-HVdc converter inertia constant [111]⁷:

$$\tau = \frac{C_{dc} V_{dc}^2}{2S_n} \quad (4.10)$$

Voltage-source converter

Due to the switching behaviour of the several IGBTs constituting a VSC, the dynamic equations describing the converter operation are discontinuous and complex to solve. One way to deal with complex power electronic converter modelling is to employ averaged dynamic



(a) Dry: 750 μ F, 1210 V [109]



(b) Oil: 1600 μ F, 2900 V [109]



(c) Alstom HVDC Maxsine valve submodule [58]

Figure 4.12: Capacitors for HVdc applications.

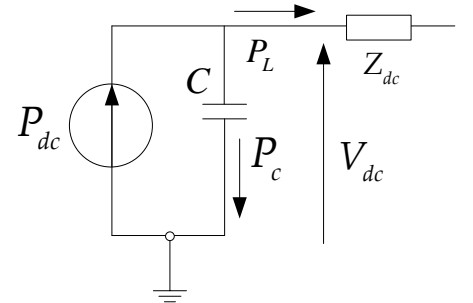
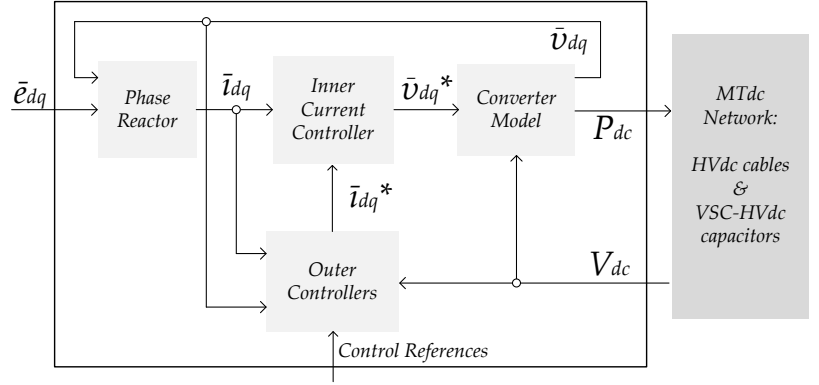


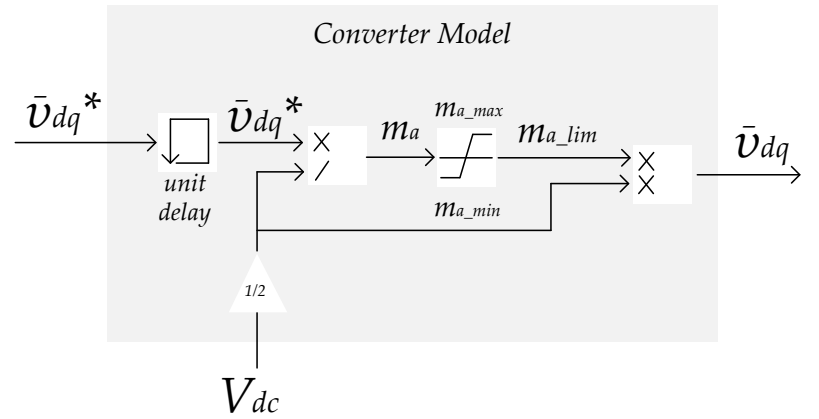
Figure 4.13: Equivalent dc-side circuit of a VSC-HVdc station.

⁷ As discussed in Section 1.3, a 1-GW VSC-HVdc converter with a direct voltage of ± 320 kV and an output capacitance of 100 μ F, has an inertia constant $\tau \approx 20$ ms, which is 50 to 500 times less than that of an synchronous machine.

Figure 4.14: VSC-HVdc system modular dynamic models.



(a) Complete VSC-HVdc station



(b) Voltage-source converter model

models, whose main purpose is to simplify the converter analysis while still allowing enough details to understand its dynamics and to develop control strategies [30].

The VSC model used in this thesis is an averaged lossless model⁸. The developed VSC-HVdc station model is modular and contains the following modules, viz.: a phase reactor; an inner current controller; the converter model; the outer controllers; and the station capacitor [29].

Figure 4.14 (a) depicts the signal-flow inside the complete VSC-HVdc model, whereas Figure 4.14 (b) displays the converter model block.

In average power electronic converter models one time-step delay is usually introduced due to the controller computational time, the converter blanking time, and to avoid algebraic loops during numerical simulation [112]; therefore:

$$\bar{v}_{dq}(k+1) \approx \bar{v}_{dq}^*(k) \quad (4.11)$$

where;

$\bar{v}_{dq}(k+1)$ are the converter ac-side voltage at time-step $k+1$ [V] and; $\bar{v}_{dq}^*(k)$ are converter reference voltage at time-step k [V].

Additionally to the time-step delay, the converter model shown in Figure 4.14 (b) also contains a scheme to limit the modulation index so that the maximum fundamental harmonic the VSC can generate

⁸ The closed-loop bandwidth of a VSC current controller is usually kept at least 5 times lower than the converter switching frequency. Therefore, the converter switching behaviour can be neglected when evaluating its dynamic response inside MTdc networks. The controls structure of a VSC is discussed next in Section 4.3.

is a function of the direct voltage as shown in (4.1).

Nevertheless, a more detailed switching model of the converter may be of interest when commutation losses, switching harmonics, or ripple in the converter currents need to be taken into consideration. The mathematical description of modulated converter voltages in the 3-phase frame is then given by [30]:

$$v_{ci} = \frac{1}{2} \left(\delta_i(t) - \frac{1}{3} \sum_{i=a,b,c} \delta_i(t) \right) V_{dc}(t) \quad (4.12)$$

where;

v_{ci} is the converter phase i voltage ($i = a, b, c$) [V] and;

δ_i switching function for phase i .

4.3 VSC-HVdc Control

The basic operation of a VSC-HVdc transmission system can be described by considering each converter terminal as a controllable-voltage source connected to an ac transmission network through means of a series-connected phase reactor (see Figure 4.11) [112,113].

A VSC can control the active and the reactive power through the ac transmission system in an independent way. The goal of the VSC controller is to set the amplitude, the angle and the frequency of the converter phase voltages. There are two main control strategies to achieve that objective: direct control and vector control [46,114]. Recently, another control strategy has been proposed, known as power-synchronisation control, which augments the maximum transferable power through the VSC link [115,116]⁹.

Direct control

The direct control strategy is very straightforward as it deals with the converter alternating currents and voltages directly in the three-phase (abc) frame, without the need for coordinate transformations. The control principle is simple and the current references are calculated based on the load flow equations between two nodes [117,118].

However, as the current references are directly calculated, this control strategy does not contain an inner-current loop. Therefore, it is not possible for the direct control to protect the converter valves against overcurrents, which is the main reason why this kind of control strategy is usually not employed in VSC-HVdc systems, which have very little overcurrent capability.

Power-synchronisation control

The main idea behind power-synchronisation control is to make the grid-connected VSC have a dynamic response which is similar to that of a synchronous machine to overcome some of the difficulties of vector-current control, namely when the VSC is connected to a weak (low short-circuit ratio) ac network [32].

⁹ This thesis focuses on the analysis of vector control as this is the most employed VSC control structure. However, for completeness, direct control and power-synchronisation control are briefly described.

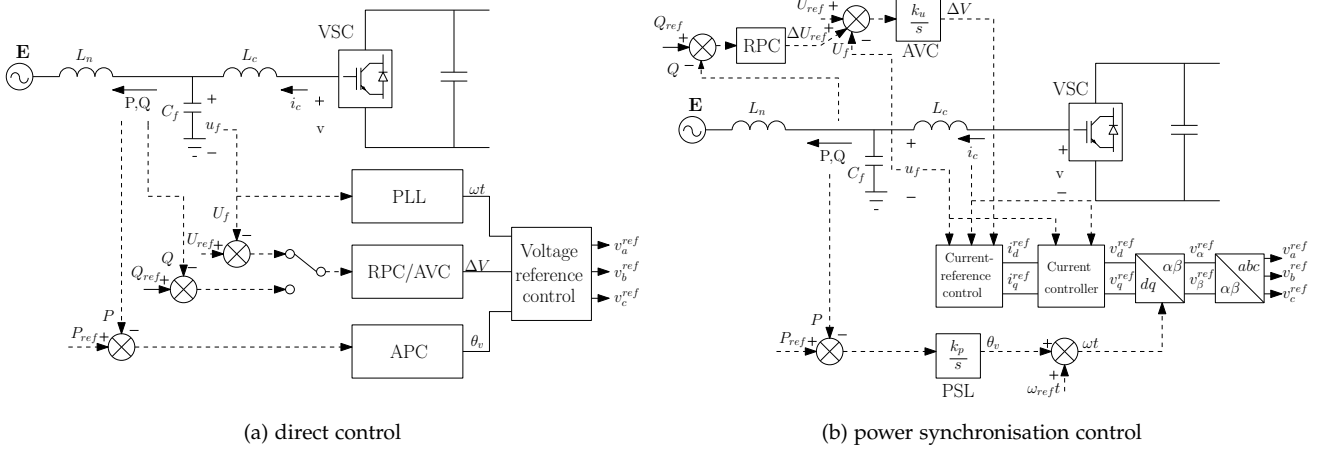


Figure 4.15: VSC control structure: (a) direct control and (b) power synchronisation control [32].

The converter maximum transferable power is a very important criteria for control design and stability analysis [116]. The power-synchronisation control allows the VSC-HVdc to maintain steady operation for higher load angles. As a result, the VSC is then able to exchange more power with the ac network. Figure 4.15 shows the diagrams of the direct control and of the power-synchronisation control [32].

Vector control

In vector control, the converter currents and the three-phase voltages are transformed to the rotating direct-quadrature frame, which will be then synchronised with the ac network voltage through means of a phase-locked loop (PLL). A simplified diagram representation of the vector control structure is displayed in Figure 4.16¹⁰.

The control system determines the converter voltage reference in the (dq) frame via an inner-current controller, and this signal is fed back to the converter after it is re-transformed to the three-phase (abc) frame [119–122].

A well designed closed-loop current controller, with a sufficiently

¹⁰ The model shown in Figure 4.14 and its representation, shown in Figure 4.16, do not yet include the ac-side LCL filter, phase-locked loop (PLL) and the PWM modulator. The first two – ac-filter and PLL – will be examined in more details in the VSC-HVdc small-signal model, developed in Chapter 8; whereas the PWM modulator is further analysed during the laboratory experiments, which are presented in Chapter 9.

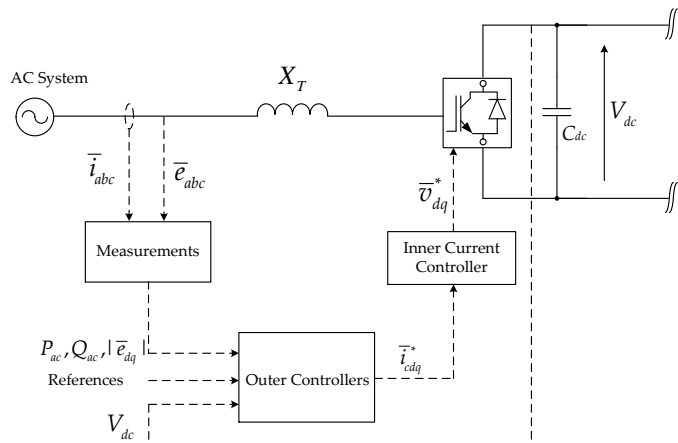


Figure 4.16: Structure of VSC vector control strategy.

high control bandwidth, improves the system response by providing damping effect [123]. Additionally, it helps, in steady state, to eliminate the cross-coupled interactions between the direct and quadrature axes, and reduces the effect of the grid side voltage variations on the converter current [112,114]. Next, the inner current controller and the outer controllers are discussed in detail.

Inner Current Controller (ICC)

For VSC-HVdc applications, the preferred switch is the insulated gate bipolar transistor, because it is relatively easy to control and its has high current and voltage ratings. In high-power applications, the converter switching frequency is limited by the losses that occur mainly during the switching of the IGBT valves. Thus, for VSC-HVdc systems, the switching frequency will be much slower than for low power applications, typically lying in the 1-2 kHz range¹¹.

In a voltage-source converter, the switching frequency limits how fast the converter can react to changes from one operating point to another. Therefore, the maximum achievable current control bandwidth is also limited by the applied switching frequency. On the other hand, the controller bandwidth relates to how fast and accurately a signal can change in time and, therefore, how fast and accurate the system response can be¹².

It is possible calculate the control bandwidth of a VSC inner current control, by applying the Laplace transformation to (4.7), which gives the current at the VSC phase reactor:

$$sL_T\bar{i}_{dq} = \bar{e}_{dq} - \bar{v}_{dq} - R_T\bar{i}_{dq} - j\omega L_T\bar{i}_{dq} \quad (4.13)$$

Figure 4.17 gives the block diagram representation of the equations shown in (4.13). The resulting system is linear and autonomous, i.e. does not depend on time as an independent variable, if ω is constant. This assumption is common in the study of electrical networks

¹¹ For low power applications – IGBT switches of 600 V and 50 A ratings – it is possible to apply switching frequencies of over 20 kHz. However, for HVdc applications more bulky switches are needed. Modern high-power IGBTs can have voltage rating of up to 6.5 kV (Field-stop IGBT with $I_{max} = 600$ A) and carry up to 1200 A (non-punch-through IGBT with $V_{max} = 3.3$ kV) [124].

¹² The term bandwidth can relate to different subjects, such as telecommunications, informatics and electronics. In signal processing and control theory, the obtainable bandwidth is the frequency at which the gain of the closed-loop transfer function falls 3 dB from the dc gain or, equivalently, the frequency at which the open-loop system gain cross the 0 dB line.

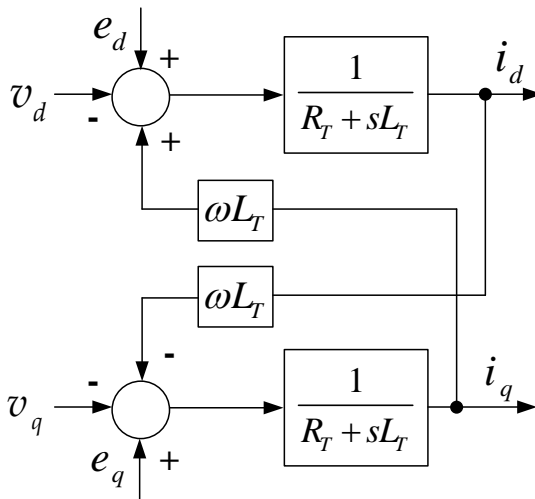


Figure 4.17: Block diagram representation of the VSC-HVdc state-space equations.

¹³ An identical expression can be written for the VSC d-axis voltage i_d/v_d , just by properly changing the d and q subscripts in (4.14).

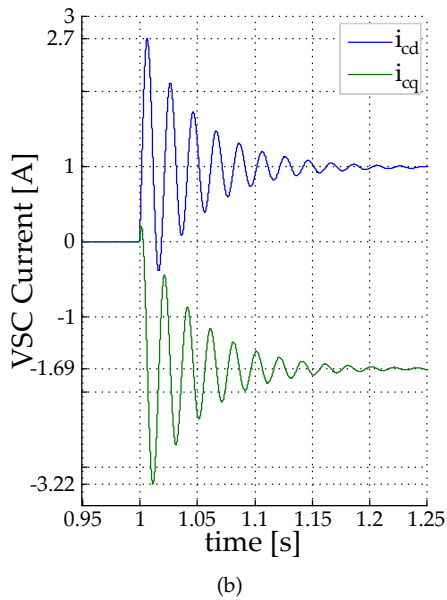
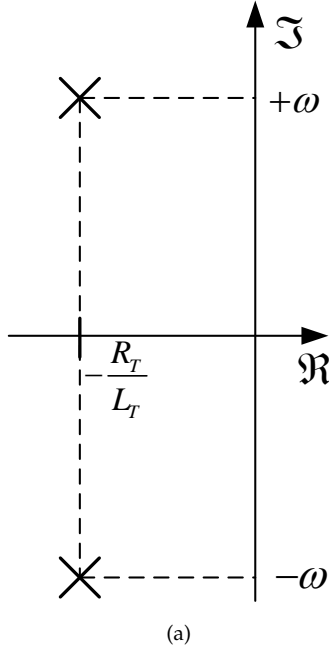


Figure 4.18: Root locus (a) and step response (b) of a VSC without feedback current control.

since only very small frequency deviations are allowed during normal operation of large utility grids.

With regard to Figure 4.17, it is possible to write the following transfer function for the VSC q-axis voltage¹³:

$$\frac{i_q}{-v_q} = \frac{1}{\frac{R_T + sL_T}{1 + \frac{(\omega L_T)^2}{(R_T + sL_T)^2}}} = \frac{R_T + sL_T}{\left(s + \frac{R_T}{L_T}\right)^2 + \omega^2} \quad (4.14)$$

where;

i_q is the current in the q-axis [A] and;

v_q is the converter voltage in the q-axis [V].

The poles of the system shown in Figure 4.17 are equal the roots of the following characteristic equation: $(s + R_T/L_T)^2 + \omega^2 = 0$, which is the denominator of (4.14).

For $\omega = 2\pi f$, where f is the ac network frequency (50 Hz), the poles of the non-feed back VSC system will be complex, i.e. oscillatory. Hence, without feedback of the converter currents, this system is poorly damped and has a very bad dynamic performance (under-damped response).

The system root-locus diagram, as well as a step response, for a VSC station with $R_T = 0.01$ pu and $L_T = 0.15$ pu, are shown in Figure 4.18. The converter current response is very slow – around 200 ms – and definitively not satisfactory as the current overshoots to more than twice the final value.

The solution to improve the VSC system performance is to feed back the converter current through a controller closing the current loop. The new system block diagram is presented in Figure 4.19. The feedback will improve the system response by shifting the poles of the open-loop transfer function towards the real-axis of the root-locus diagram, resulting in a critically-damped or over-damped system response.

Considering the controller to be a simple proportional gain, i.e. $C(s) = K_p$, the block diagram presented in Figure 4.19 can be simplified by solving the outer feedback loops. In fact, the transfer function

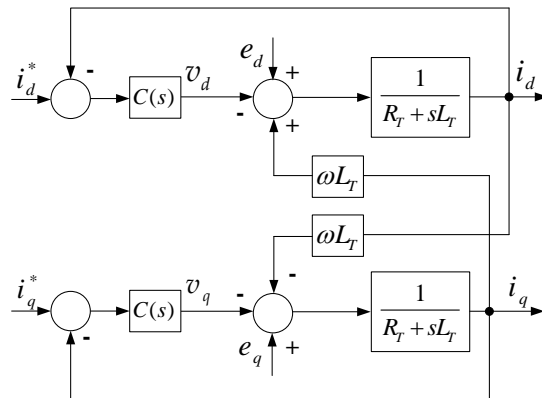


Figure 4.19: Block diagram representation of the VSC-HVdc state-space equations with feedback control.

of the outer feedback loops are given by:

$$\frac{K_p \cdot \frac{1}{R_T + sL_T}}{1 + K_p \cdot \frac{1}{R_T + sL_T}} = \frac{K_p}{K_p + R_T + sL_T} \underset{K_p \gg R_T}{\approx} \frac{1}{1 + sL_T/K_p} \quad (4.15)$$

Assuming that the ICC proportional gain, K_p , is much higher than the total resistance between the VSC and the ac network, the equivalent block diagram representation of the VSC-HVdc with the proportional controller becomes the one shown in Figure 4.20, for which it is possible to derive¹⁴:

$$\begin{aligned} \frac{i_q}{i_q^*} &= \frac{\frac{1}{1 + s\frac{L_T}{K_p}}}{1 + \left(\frac{\omega L_T}{K_p}\right)^2 \frac{1}{\left(1 + s\frac{L_T}{K_p}\right)^2}} = \frac{1 + s\frac{L_T}{K_p}}{\left(\frac{\omega L_T}{K_p}\right)^2 + \left(1 + s\frac{L_T}{K_p}\right)^2} \\ &= \frac{1 + s\frac{L_T}{K_p}}{\left(1 + \frac{\omega L_T}{K_p} + s\frac{L_T}{K_p}\right) \left(1 - \frac{\omega L_T}{K_p} + s\frac{L_T}{K_p}\right)} \approx \frac{1}{1 + s\frac{L_T}{K_p}} \end{aligned} \quad (4.16)$$

where;

i_q^* is the converter inner-current controller reference in the q-axis [A].

The system resulting from (4.16) is a first-order linear system. Therefore, having a high proportional gain in the inner-current controller not only improves the system response, but also helps, in steady state, to eliminate the cross-coupled interaction between the d-axis and q-axis, and to reduce the effect of the ac grid voltage variations on the converter current. During steady state, $s = 0$ [125], thus, for the system shown in Figure 4.20, it follows that¹⁵:

$$\begin{cases} \frac{i_q}{i_q^*} = \frac{1}{1 + \left(\frac{\omega L_T}{K_p}\right)^2} \approx 1 \\ \frac{i_q}{e_q} = \frac{\frac{1}{K_p}}{1 + \left(\frac{\omega L_T}{K_p}\right)^2} \approx \frac{1}{K_p} \\ \frac{i_q}{i_d^*} = \frac{\frac{\omega L_T}{K_p}}{1 + \left(\frac{\omega L_T}{K_p}\right)^2} \approx \frac{\omega L_T}{K_p} \end{cases} \quad (4.17)$$

where;

e_q is the ac network voltage in the q-axis [V] and;

i_d^* is the converter inner-current controller reference in the d-axis [A].

¹⁴ An identical expression can be written for the VSC d-axis current i_d/i_d^* , by properly changing the d and q subscripts in (4.16).

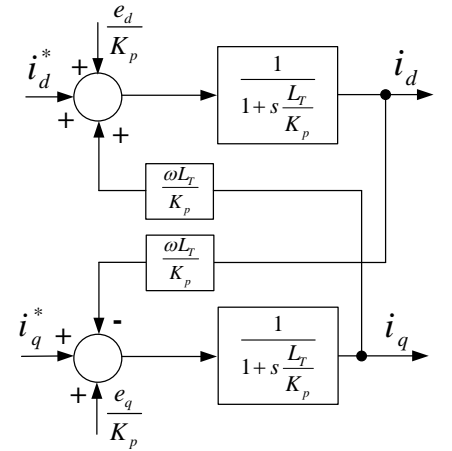


Figure 4.20: Equivalent block diagram representation of the VSC-HVdc with inner current controller.

¹⁵ Once again identical expressions can be written for the i_d/i_d^* , i_d/e_d and i_d/i_q^* transfer functions in the d-axis, by properly changing the d and q subscripts in (4.17).

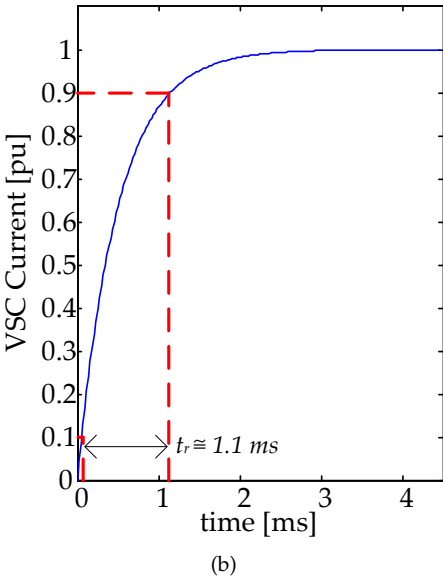
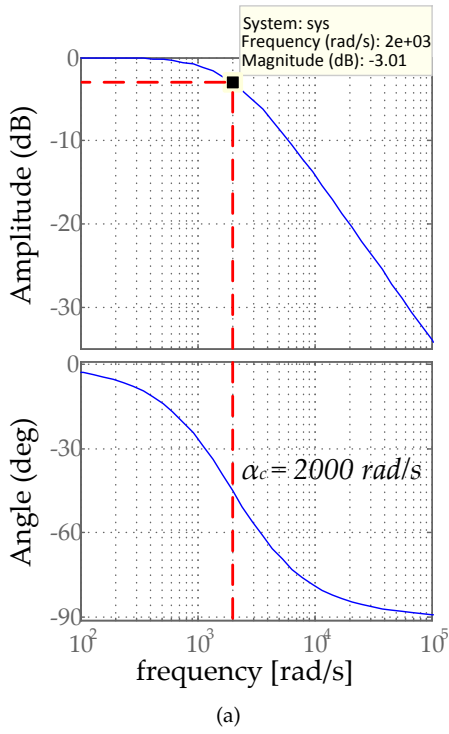


Figure 4.21: Bode plot (a) and step response (b) of a VSC with feedback current control.

¹⁶ As shown in (4.17), the steady-state error is very small and equal to:

$(\omega L_T / K_p)^2 = (100\pi \cdot 0.160 / 320)^2$;
i.e. less than 2.5% for the system displayed in Figure 4.21.

In fact, analysing the equations in (4.17) it is possible to affirm that, if $\omega L_T / K_p \ll 1$, the converter current will follow exactly the reference from the inner-current controller ($i_q = i_q^*$); the effects of the ac-grid voltage variations on the converter current will be damped by the controller ($i_q = e_q / K_p$); and that changes in the d-axis current reference will not affect the converter q-axis current ($i_q = \omega L_T / K_p i_d^*$); i.e. the cross-coupling influence between the d and q axes are canceled out.

Therefore, starting from the oscillatory system of (4.14), by adding a proportional controller and closing the current-loop, the VSC-HVdc system now resembles a first-order system. The bode plot for the resulting VSC-HVdc system, based on (4.16), with a phase-reactor of $L_T = 160$ mH and a proportional gain of $K_p = 320 \Omega$ is shown in Figure 4.21. The system has a pole in $-K_p / L_T$, which is equal its closed-loop bandwidth, $\alpha_c = 2$ krad/s.

For a satisfactory dynamic performance, when using carrier-based PWM or SVPWM modulation techniques, the closed-loop bandwidth, α_c , should not be higher than 5 times the angular switching frequency, ω_{sw} , and the switching frequency should not be lower than half the sampling frequency, ω_s , i.e. [126,127]:

$$\alpha_c \leq \frac{\omega_{sw}}{5} \leq \frac{\omega_s}{10} \quad (4.18)$$

Therefore, with a switching frequency of 2 kHz (12.56 krad/s), the maximum system bandwidth, α_c , would be of approximately 2.5 krad/s (or circa 400 Hz). In a first-order system the rise time, t_r , in seconds, for the system output to go from 10 to 90% output is given by [112]:

$$t_r = \ln(9) / \alpha_c \quad (4.19)$$

Hence, the minimum current rise-time of a VSC system, switching at 2 kHz, is approximately 1 ms, as shown in Figure 4.21.

In conclusion, the value of the proportional gain, K_p , is fixed by the obtainable bandwidth which, on the other hand, is related to the switching frequency. To obtain the desired closed-loop bandwidth it is necessary to make $K_p = \alpha_c L_T$. Given the fact that K_p is limited, and cannot be made higher due to the switching frequency and stability limitations, there will be a small error, in steady state, in the inner current controller response¹⁶.

Outer Controllers

The inner current controller is responsible for generating the VSC reference voltages according to:

$$\begin{cases} v_d^* = e_d - K_p(i_d - i_d^*) - K_i \int (i_d - i_d^*) dt + \omega L_T i_q \\ v_q^* = e_q - K_p(i_q - i_q^*) - K_i \int (i_q - i_q^*) dt - \omega L_T i_d \end{cases} \quad (4.20)$$

In (4.20), the outer controllers are the ones responsible for providing the references signals, (i_d^*, i_q^*) , for the inner current controller. For a VSC-HVdc system there are basically two categories of outer controllers: the ones related with the active power channel – active power controller, direct voltage controller, and frequency controller – and the ones related with the reactive power channel – reactive power controller and alternating voltage controller. Next, the active and reactive power controllers are discussed, followed by a detailed analysis of the direct voltage controller. Lastly, the alternating voltage controller is presented.

Active and reactive power controllers

The expressions to evaluate the active and the reactive power flowing through the converter to the ac grid, in the (dq) frame, are formally given as¹⁷:

$$\begin{cases} P_{ac} = e_d \cdot i_d + e_q \cdot i_q \\ Q_{ac} = e_q \cdot i_d - e_d \cdot i_q \end{cases} \quad (4.21)$$

If, under steady state conditions, the ac network is balanced and the q-axis of the (dq) rotating frame is aligned with the ac network voltage phasor, the active power channel outer controllers will provide the current reference for the q-axis, whereas the reactive power channel controllers will provide the current reference for the d-axis. Substituting $e_d = 0$ in (4.21) yields:

$$\begin{cases} P_{ac}^* = e_q \cdot i_q^* \\ Q_{ac}^* = e_q \cdot i_d^* \end{cases} \Rightarrow \begin{cases} i_q^* = P_{ac}^* / e_q \\ i_d^* = Q_{ac}^* / e_q \end{cases} \quad (4.22)$$

where;

P_{ac}^* is the active power reference at the ac-grid side [W] and;

Q_{ac}^* is the reactive power reference at the ac-grid side [VAr].

The equations shown in (4.22) give the references values for open-loop active and reactive power controllers. To cancel the steady-state error, proportional-integral (PI) regulators are used, in a closed-loop controller. Figure 4.22 shows the resulting diagram for the active and reactive power outer controllers. The control diagrams presented in Figure 4.22 can be mathematically expressed as¹⁸:

$$\begin{cases} i_d^* = (Q_{ac}^* - Q_{ac}) \cdot \left(K_p^Q + \frac{K_i^Q}{s} \right) \\ i_q^* = (P_{ac}^* - P_{ac}) \cdot \left(K_p^P + \frac{K_i^P}{s} \right) \end{cases} \quad (4.23)$$

where;

K_p^P is the active power controller proportional gain [A/W];

K_i^P is the active power controller integral gain [A/Ws];

K_p^Q is the reactive power controller proportional gain [A/VAr] and;

K_i^Q is the reactive power controller integral gain [A/VAr s].

¹⁷ for the Park-Transformation that conserves the definition of power from the (abc) to the (dq) frame.

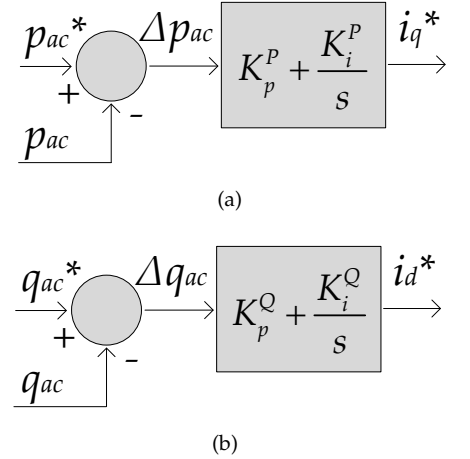


Figure 4.22: VSC outer controllers: (a) active power and (b) reactive power.

¹⁸ In this thesis, as the ac grid voltage, \bar{e}_{dq} , is aligned with the q-axis of the rotating frame, i.e. $e_d = 0$, therefore, the d-axis becomes the reactive power channel and the q-axis will be the active power channel.

Direct voltage controller

The direct voltage controller is certainly the most important one in a VSC-HVdc transmission system. A well controlled MTdc network voltage is a guarantee of power balance between all the converter stations. If the dc system voltage starts to increase excessively, it may trigger protective equipment, such as dc choppers with dump resistors. On the other hand, a large direct voltage drop might generate nonlinear phenomena, creating difficulties for the control systems, and also temporarily limit the capability of the ac system voltage controller [116].

Considering a lossless VSC station, the converter power in the ac-grid side, P_{ac} , and in the dc-grid side, P_{dc} , are¹⁹:

$$P_{ac} = P_{dc} = (e_d i_d + e_q i_q) = V_{dc} I_{dc} \quad (4.24)$$

In a MTdc network, the VSC-HVdc station can be represented by a controllable current source, $I_{dc}(s)$. Kirchhoff's current law applied to the VSC station yields:

$$\frac{P_{dc}(s)}{V_{dc}(s)} = I_{dc}(s) = I_L(s) + I_c(s) \quad (4.25)$$

where;

I_{dc} is the VSC direct current [A];

I_L is the current flowing into the MTdc grid [A] and;

I_c is the current through the VSC output dc capacitor [A].

The direct voltage at the VSC capacitor is given as:

$$V_{dc}(s) = \frac{I_c(s)}{sC_{dc}} \quad (4.26)$$

From the above equations a direct voltage controller, which operates on the error, $\Delta V_{dc} = V_{dc}^* - V_{dc}$ could be developed, in an analogous way as the active and reactive power outer controllers shown in Figure 4.22. However, if the controller would operate linearly on the direct voltage, the closed-loop dynamics would be dependent on the operating point, as I_{dc} is inversely proportional to V_{dc} .

As an alternative, the direct voltage outer controller operates on the square of the direct voltage, $V_{dc}^2 = W_{dc}$, which is proportional to the energy stored in the VSC-HVdc station capacitor. Starting from (4.9), it is possible to write:

$$\begin{cases} W_c = \int (P_{dc} - P_L) dt \\ W_c = \frac{1}{2} C V_{dc}^2 \Rightarrow V_{dc}^2 = W_{dc} = \frac{2}{C} W_c \end{cases} \quad (4.27)$$

where;

W_{dc} is equal the square of the VSC direct voltage [V^2].

The control structure of the VSC-HVdc system (see Figure 4.20) is then extended to include the direct voltage controller. The direct voltage outer controller operates on the error $\Delta W_{dc} = W_{dc}^* - W_{dc}$, which is proportional to the energy stored in the VSC capacitor. The

¹⁹ Considering the converter to be lossless is an obvious source of error. However, the losses in a VSC-HVdc station are very small, usually less than 1.5% (see Table 2.1). Moreover, VSC losses have a non-linear nature [128], and representing them is out of the scope of the present thesis.

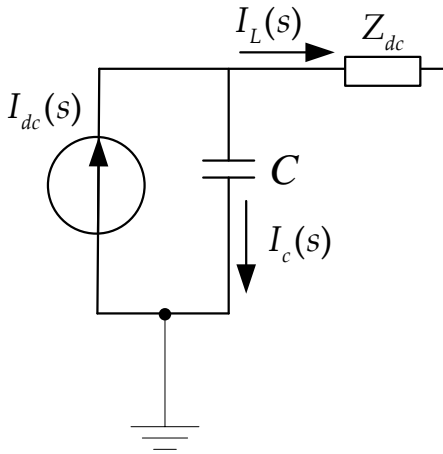


Figure 4.23: Equivalent circuit of the VSC-HVdc station dc side.

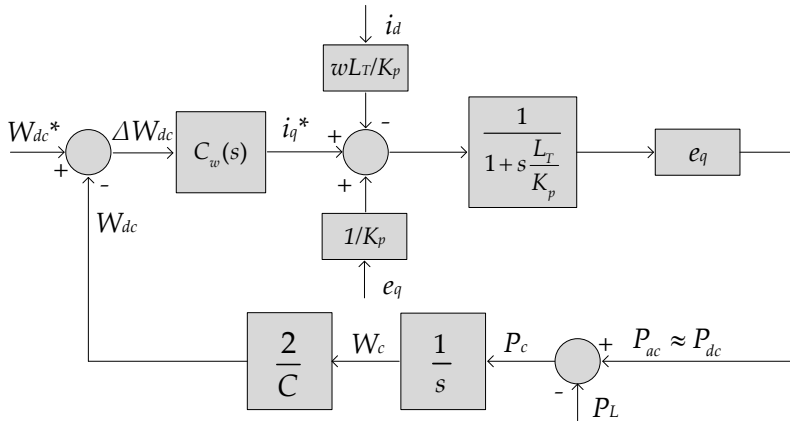


Figure 4.24: Closed-loop diagram of the active power channel in a VSC-HVdc station.

resulting diagram is displayed in Figure 4.24, where $C_w(s)$ is the direct voltage controller transfer function.

Direct voltage controller closed-loop bandwidth

To obtain an expression for the bandwidth of the direct voltage controller it is necessary to derive its transfer function. If the inner-current controller gain, K_p , is made high enough – i.e. the current controller bandwidth is sufficiently high – it is possible to disregard the cross-coupling interaction between the d-axis and q-axis controllers, as well as the influence of the ac network voltage on the converter current.

As a result, based on Figure 4.24, it is possible to derive the relationship between the square of the VSC direct voltage reference, W_{dc}^* and the square of the direct voltage, W_{dc} :

$$\frac{W_{dc}}{W_{dc}^*} = \frac{C_w(s) \cdot \frac{1}{1+s\frac{L_T}{K_p}} \cdot e_q \cdot \frac{2}{sC_{dc}}}{1 + C_w(s) \cdot \frac{1}{1+s\frac{L_T}{K_p}} \cdot e_q \cdot \frac{2}{sC_{dc}}} = \frac{2C_w(s)K_p e_q}{s^2 L_T C_{dc} + sC_{dc}K_p + 2C_w(s)K_p e_q} \quad (4.28)$$

where;

W_{dc}^* is equal the square the direct voltage reference [V^2].

If the ac grid voltage is equal to its rated value ($e_g = 1$ pu), and the direct voltage controller is just a proportional gain²⁰, i.e. $C_w(s) = k_p^w$, then (4.28) can be re-written as:

$$\frac{w_{dc}}{w_{dc}^*} = \frac{2k_p^w k_p}{s^2 l_T c_{dc} + s c_{dc} k_p + 2k_p^w k_p} \quad (4.29)$$

where;

w_{dc} is the square of the VSC direct voltage [pu];

w_{dc}^* is the square of the VSC direct voltage reference [pu];

k_p^w is the direct voltage controller proportional gain [pu];

²⁰ This type of direct voltage controller is also referred to in the related literature as droop controller [129]. The droop control strategy for MTdc networks is further analysed in Chapter 5.

k_p is the ICC proportional gain [pu];

l_T is the total inductance between the VSC and the ac grid [pu] and;

c_{dc} is the VSC output capacitance [pu].

The direct voltage controller closed-loop transfer function presented in (4.29) has two poles and no zeros. The system poles, $p_{1,2}$, are equal the roots of the closed-loop transfer function denominator, i.e.:

$$p_{1,2} = \left\{ -\frac{1}{2l_T c_{dc}} \left(c_{dc} k_p \pm \sqrt{(c_{dc} k_p)^2 - 8k_p^w k_p l_T c_{dc}} \right) \right\} \quad (4.30)$$

For the direct voltage controller to be stable, it is sufficient that the real part of the transfer function poles is negative, i.e. the poles are located on the open left-side plane of the root-locus diagram. Since $\Re(p_{1,2}) < 0$ for any given value of k_p^w , the presented closed-loop controller is always stable. Nevertheless, the location of poles $p_{1,2}$ depend on the choice of k_p^w , the direct voltage controller proportional gain²¹.

For constructing the direct voltage controller root-locus diagram, consider initially its proportional gain to be null, i.e. $k_p^w = 0$. In that case:

$$p_{1,2}|_{k_p^w=0} = \left\{ -\frac{k_p}{l_T}, 0 \right\} = \left\{ -\alpha_c^{pu}, 0 \right\} \quad (4.31)$$

where;

α_c^{pu} is the ICC closed-loop bandwidth [pu].

As it can be seen from (4.31), the obtained poles are equal the inner current controller closed-loop bandwidth, α_c^{pu} , plus a pole at the origin from the dc capacitor. The resulting bandwidth of the direct voltage outer controller will be given by the pole with the smallest absolute magnitude, therefore it is convenient to increase the proportional gain, k_p^w , as the smallest pole, $s = 0$, is in the root-locus diagram origin.

Increasing the k_p^w , until the discriminant of (4.30) is null yields:

$$\begin{cases} \text{if } (c_{dc} k_p)^2 - 8k_p^w k_p l_T c_{dc} = 0 \Rightarrow k_p^w = \frac{1}{8} \frac{k_p}{l_T} c_{dc} = \frac{1}{8} \alpha_c^{pu} c_{dc} \\ \Leftrightarrow p_{1,2} = \left\{ -\frac{1}{2} \frac{k_p}{l_T}, -\frac{1}{2} \frac{k_p}{l_T} \right\} = \left\{ -\frac{1}{2} \alpha_c^{pu}, -\frac{1}{2} \alpha_c^{pu} \right\} \end{cases} \quad (4.32)$$

As shown in (4.32), in the situation where the proportional gain is made equal $\alpha_c^{pu} c_{dc} / 8$, both the closed-loop poles will fall exactly on half of the current controller closed-loop bandwidth. If k_p^w is further increased past $\alpha_c^{pu} c_{dc} / 8$, the discriminant of (4.30) will become lower than zero and the poles of the direct voltage controller will be of the following form:

$$\begin{cases} \text{if } (c_{dc} k_p)^2 - 8k_p^w k_p l_T c_{dc} < 0 \Rightarrow k_p^w > \frac{1}{8} \alpha_c^{pu} c_{dc} \\ \Leftrightarrow p_{1,2} = \left\{ -\frac{1}{2} \alpha_c^{pu} \pm j \cdot |f(k_p^w)| \right\} \end{cases} \quad (4.33)$$

²¹ Considering the fact that K_p was already set equal to $\alpha_c l_T$ to obtain the desired inner-current controller bandwidth, α_c .

where;

$|f(k_p^w)|$ is a function of the direct voltage controller proportional gain [rad/s].

Therefore, as the direct voltage controller gain, k_p^w , grows larger than $\alpha_c^{pu} c_{dc}/8$, the poles of the closed-loop system will become progressively oscillatory. The resulting direct voltage controller root-locus diagram is shown in Figure 4.25.

Fixing $k_p^w = \alpha_c^{pu} c_{dc}/8$, it is possible to obtain the direct voltage controller open-loop Bode plot:

$$\left. \frac{w_{dc}}{w_{dc}^*} \right|_{open} = k_p^w \frac{1}{1+s \frac{l_T}{k_p}} \frac{2}{s c_{dc}} = \frac{1}{4} \frac{k_p}{l_T} \frac{1}{1+s \frac{l_T}{k_p}} \frac{1}{s} = \frac{\frac{\alpha_c^{pu}}{4}}{\left(1+s \frac{1}{\alpha_c^{pu}}\right) \cdot s} \quad (4.34)$$

Now substituting the same k_p^w into the closed-loop transfer function, given in (4.28), yields:

$$\begin{aligned} \left. \frac{w_{dc}}{w_{dc}^*} \right|_{closed} &= \frac{2k_p^w k_p}{s^2 l_T c_{dc} + s c_{dc} k_p + 2k_p^w K_p} \\ &= \frac{\frac{1}{l_T^2} \left(\frac{1}{2} k_p\right)^2}{\left(s^2 + s \frac{k_p}{l_T} + \left(\frac{1}{2} \frac{k_p}{l_T}\right)^2\right)} = \frac{1}{\left(s \cdot \frac{2}{\alpha_c^{pu}} + 1\right)^2} \end{aligned} \quad (4.35)$$

As shown by the root-locus diagram in Figure 4.25, the direct voltage controller closed-loop transfer function has, for the given value of k_p^w , two poles in half of the current controller bandwidth. The open-loop controller in its turn has a pole at the origin (due to the presence of the VSC station capacitor) and a pole in α_c , due to the inner-current controller. In reality, the direct voltage controller open-loop Bode plot crosses the 0 dB axis at a frequency of $0.243\alpha_c \approx \alpha_c/4$, whereas its closed-loop Bode plot has a -3 dB gain at a frequency of circa $0.321\alpha_c$ (see Figure 4.27).

The performed analysis has led to a maximum value for the direct voltage controller gain, which can in its turn be related to the inner current controller bandwidth. In fact, for the inner current controller:

$$\alpha_c^{pu} = \frac{k_p}{l_T} \Rightarrow k_p = \alpha_c^{pu} \cdot l_T \quad (4.36)$$

Limiting the direct voltage controller bandwidth to its open-loop transfer function bandwidth value, yields:

$$\begin{cases} \alpha_{dc}^{pu} \leq \frac{\alpha_c^{pu}}{4} \\ \Rightarrow k_p^w \leq \frac{1}{8} \alpha_c^{pu} \cdot c_{dc} = \frac{\alpha_{dc}^{pu} \cdot c_{dc}}{2} \end{cases} \quad (4.37)$$

where;

α_{dc}^{pu} is the bandwidth of the direct voltage controller [pu].

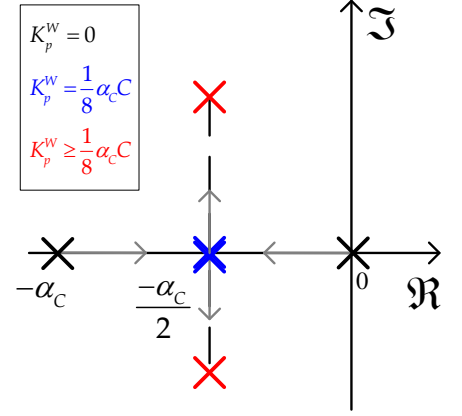


Figure 4.25: Root-locus diagram of the active power channel in a VSC-HVdc station.

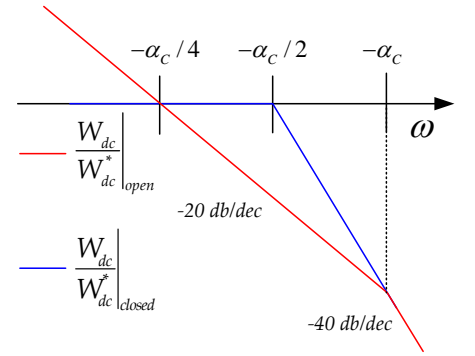


Figure 4.26: Bode plot of the direct voltage controller open-loop and closed-loop transfer function with regard to the reference value.

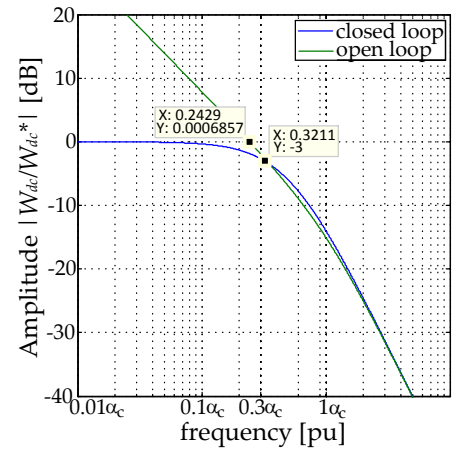


Figure 4.27: Numerically obtained Bode plot of the direct voltage controller open-loop and closed-loop transfer function.

²² In practice, the limit for the VSC outer controller bandwidth will be lower than $0.25\alpha_c$, since some simplifications were introduced in the analysis. For instance, the cross-coupling effect between the d and q axes was neglected, the presence of the PLL, dead-time of the switches, delays for digital processing and sampling, as well as the converter switching behaviour [125–127]. Industry experts suggest that, as a rule of thumb, $\alpha_{dc} \leq 0.10 \cdot \alpha_c$, to allow for sufficient phase margin and to account for all the aforementioned simplifications during the deriving of the equations [112].

The result presented in (4.37) gives a theoretical limit for the direct voltage controller proportional gain and maximum achievable bandwidth²².

Direct voltage controller load rejection

The analysis conducted thus far took into consideration just one VSC-HVdc station. The interaction between VSC stations in a MTdc network can be analysed by considering the power flowing through the dc transmission system as a disturbance. From Figure 4.24, it is possible to obtain the transfer function of W_{dc} with regard to the power flowing into the MTdc network, P_L . Assuming that the ac network voltage is equal to its rated value, i.e. $e_q = 1$ pu, yields:

$$\frac{w_{dc}}{p_L} = \frac{-\frac{2}{sc_{dc}}}{1 + \frac{2}{sc_{dc}}C_w(s)\frac{1}{1 + s\frac{l_T}{k_p}}} = \frac{-2(k_p + sl_T)}{s^2l_Tc_{dc} + sc_{dc}k_p + 2c_w(s)k_p} \quad (4.38)$$

where;

p_L is the active power flowing into the MTdc network [pu].

As it can be seen from (4.38), if $C_w(s)$ is again considered only a proportional-gain controller, i.e. $C_w(s) = k_p^w$, the denominator of the transfer function W_{dc}/P_L will have the same poles, and thus the same closed-loop dynamics, as the W_{dc}/W_{dc}^* transfer function. The zero in the numerator of (4.38) is placed at the inner current controller bandwidth, α_c , therefore, since it has a higher frequency than the transfer function poles, it will not affect the load rejection dynamics for lower frequencies.

The Bode plot of Figure 4.26 can be expanded to include the direct voltage transfer function with regard to the power flowing into the dc transmission system. Substituting $C_w(s) = \alpha_c C/8$, into (4.38) gives:

$$\left. \frac{w_{dc}}{p_L} \right|_{closed} = \frac{-2(k_p + sl_T)}{s^2l_Tc_{dc} + sc_{dc}k_p + 2\frac{1}{8}\frac{k_p}{l_T}c_{dc}k_p} = -\frac{1}{k_p^w} \frac{\left(1 + s\frac{1}{\alpha_c^{pu}}\right)}{\left(1 + s\frac{2}{\alpha_c^{pu}}\right)^2} \quad (4.39)$$

The Bode plot in Figure 4.28 shows that for the lower frequencies, i.e. in vicinity to steady state, the load variation rejection is inversely related to the direct voltage controller proportional gain.

To understand how much will the direct voltage change for variations in the power flowing through the VSC station into the dc transmission system, it is possible to use the final value theorem, which states that:

$$\lim_{s \rightarrow 0} sF(s) = F(t = \infty) \quad (4.40)$$

If $p_L(s)$ is a sudden step change in the power being transmitted,

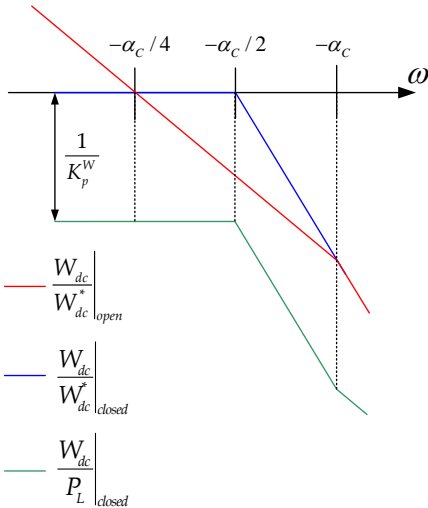


Figure 4.28: Bode plot of the direct voltage outer controller including the closed-loop transfer function with regard to the power flowing into the dc network.

then its Laplace transform is p_L/s . By substituting this value into (4.38), the final value theorem gives:

$$w_{dc}(t = \infty) = \lim_{s \rightarrow 0} s \cdot \frac{p_L}{s} \cdot \frac{-2(k_p + sl_T)}{s^2 l_T c_{dc} + s c_{dc} k_p + 2k_p^w k_p} = -\frac{p_L}{k_p^w} \quad (4.41)$$

The direct voltage variations will be directly proportional to the variations of the power flowing into the MTdc network, and inversely proportional to the gain of the direct voltage controller, as shown in the Bode plot in Figure 4.28²³.

Equation (4.41) only shows the direct voltage variation from the previous operating point. This concept is illustrated in Figure 4.29. The new operating point will be given by:

$$w_{dc} = w_{dc}^0 - \frac{\Delta p_L}{k_p^w} \quad (4.42)$$

where;

w_{dc}^0 is initial VSC direct voltage value squared [pu].

By looking at Figure 4.29, one would want to make the direct voltage controller proportional gain as high as possible to reduce voltage variations as a function of the transmitted power. However, as previously shown, the highest obtainable proportional gain, k_p^w , is limited by the inner current controller bandwidth – which is limited by the converter switching frequency – and by the size of the converter station capacitor.

As expected, the larger the station capacitor, the higher is the direct voltage load variation rejection. In addition, the higher the switching frequency, the faster the controller response can be and, once again, the higher can be the direct voltage controller load variation rejection.

For instance, if the direct voltage variations need to be kept under a maximum of 0.1 pu from its rated value, that would mean a maximum variation in the square of the direct voltage of around 0.32 pu:

$$|\Delta v_{dc}| \leq 0.1 \text{ pu} \Rightarrow |\Delta w_{dc}| \leq \sqrt{0.1} \text{ pu} \approx 0.32 \text{ pu} \quad (4.43)$$

Considering the maximum load variation to be a step start-up of a VSC station at its rated power, or a sudden block of a station when at its rated power, then: $|\Delta p_L| = 1 \text{ pu}$. Hence, it is possible to calculate the needed k_p^w to limit the direct voltage variation to the desired 0.1 pu limit:

$$\begin{aligned} |\Delta w| &= \frac{|\Delta p_L|}{k_p^w} \leq 0.32 \text{ pu} \Rightarrow k_p^w \geq \frac{|\Delta p_L|}{0.32} \\ \text{if max } |\Delta p_L| &= 1 \text{ pu} \Rightarrow k_p^w \approx 3.125 \text{ pu} \end{aligned} \quad (4.44)$$

The direct voltage controller with only a proportional regulator will present a droop characteristic, meaning that a variation in the power flowing into the MTdc line from the VSC-HVdc station will cause the direct voltage to change its operating point. In a large MTdc network, it can happen that direct voltages regulated only

²³ The minus sign in (4.41) shows that a drop in the power flowing from the VSC station to the MTdc network will cause a direct voltage rise whilst an increase in the power from the VSC station into the MTdc network will cause the direct voltage to drop.

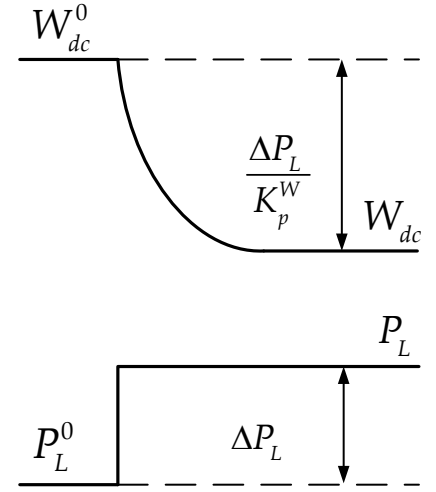


Figure 4.29: Variation of the VSC direct voltage with regard to variations in the power flowing into the MTdc transmission system.

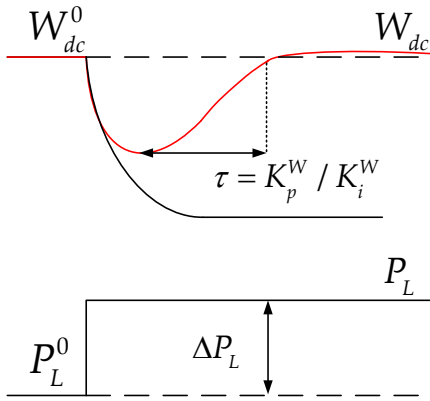


Figure 4.30: Variation of the energy stored in the VSC station capacitor to variations in the power flowing into the dc transmission system with PI controller.

through proportional control could come out of rated limits during normal system operation.

One possible solution is to maintain proportional control and, when the direct voltage comes out of bound, send a signal to the VSC stations telling the direct voltage controller to change its operating point by shifting the droop characteristic [130]. Another solution is to use a PI regulator instead.

Direct voltage controller with PI regulator

Using a direct voltage controller with a PI regulator would mean that, after a change in the power flowing into the MTdc network, the VSC direct voltage would transiently fall and subsequently return to its pre-defined due to action of the integral controller. By making use of a PI controller, the transfer function of $C_w(s)$ becomes:

$$C_w(s) = K_p^W + \frac{K_i^W}{s} = \frac{K_p^W s + K_i^W}{s} = K_p^W \frac{s + K_i^W / K_p^W}{s} \quad (4.45)$$

where;

K_i^W is the direct voltage controller integral gain [V^2/s].

The PI controller expression shows that now the regulator has a pole at the origin and a zero in the frequency $\omega_z = K_i^W / K_p^W$ [rad/s]. The PI regulator rise time from a disturbance will be approximately given by the time constant of the regulator zero, i.e. $\tau_z = K_p^W / K_i^W$ [s] (see Figure 4.30).

Therefore, it is important to have the regulator integral gain, K_i^W , as high as possible for fast response to disturbances. On the other hand, the problem with making the integral gain too high is that it reduces the system phase margin, which can make the direct voltage controller unstable [131]²⁴.

For stability reasons, the integrator zero should be kept lower than the frequency in which the open-loop transfer function crosses 0 dB. This will guarantee a sufficient phase-margin, and also an adequate gain to mitigate voltage variations due to changing in the load flowing into the MTdc network [131]. Hence:

$$\begin{cases} \frac{K_i^W}{K_p^W} \ll \frac{\alpha_c}{4} \\ \text{if } \frac{k_i^w}{k_p^w} \leq \frac{\alpha_c^{pu}}{8} = \frac{\alpha_{dc}^{pu}}{2} \\ \Rightarrow k_i^w \leq \frac{(\alpha_{dc}^{pu})^2 c_{dc}}{2} \end{cases} \quad (4.46)$$

where;

k_i^w is the direct voltage controller integral gain [pu].

Figure 4.31 displays the differences between Bode plots of the P and PI direct voltage controllers. In steady-state ($s = 0$), the error in the direct voltage controller using a PI regulator is zero due to the low gains in the load rejection transfer function W_{dc} / P_L , which, for

²⁴ The phase margin of a system is defined as the difference between the Bode phase of the open-loop transfer function and -180° at the frequency for which the magnitude of the open-loop transfer function is equal to 0 dB, i.e. the additional phase lag necessary to lead the system into instability [125,127].

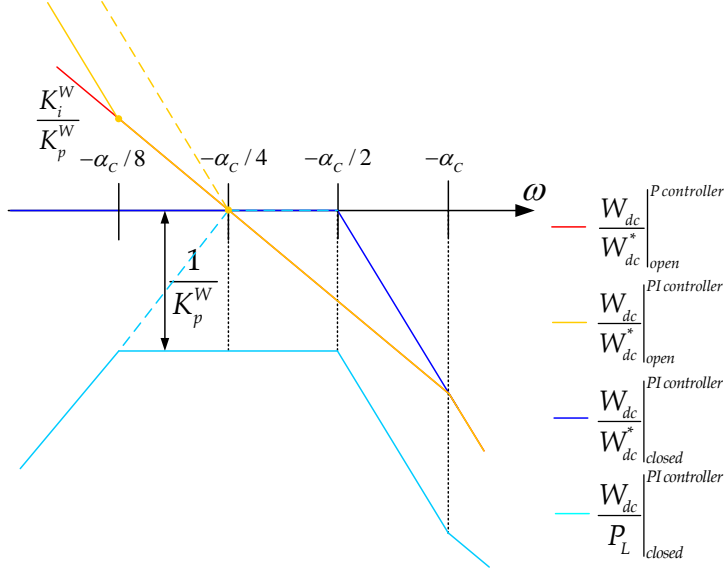


Figure 4.31: Bode plot of the energy direct voltage outer controller with a PI controller.

the lower frequencies, is not anymore limited to $1/K_p^W$, but decreases by -20 dB/dec.

In the direct voltage controller open-loop, the integral term makes the gain for the lower frequencies to rise by 40 dB/dec, instead of the previous 20 dB/dec. The new open-loop Bode plot returns to the previous one after the PI-controller zero, at the frequency K_i^W/K_p^W .

In conclusion, as previously mentioned, the rise time from disturbance of the PI regulator is equal to K_p^W/K_i^W , thus making K_i^W too small will slow-down the direct voltage recovery from a disturbance. The chosen value of the integral gain will have to be a trade-off between the rise-time to recover from disturbances, the loop gain to reject those disturbances, and the desired control stability margins.

AC network voltage controller

The ac network voltage controller, whose diagram is shown in Figure 4.32, is also a closed-loop controller and it provides the current reference for the d-axis. Thus, it is being assumed that the ac network node voltage variation depends only on the reactive power variation²⁵.

The ac network voltage is compared to the specified voltage reference, and the error generates the current reference for the d-axis, changing the amount of reactive power exchanged between the ac network and the converter (up to the limit of the converter rated power).

$$i_d^* = \left(|e_{dq}^*| - |e_{dq}| \right) \cdot \left(K_p^V + K_i^V / s \right) \quad (4.47)$$

where;

$|e_{dq}^*|$ is the ac grid voltage controller reference phasor amplitude [V];

$|e_{dq}|$ is the ac grid voltage controller phasor amplitude [V];

K_p^V is the ac network voltage controller proportional gain [A/V] and;

K_i^V is the ac network voltage controller integral gain [A/Vs].

²⁵ This assumption is described in more details in the Fast Decoupled load flow analysis, proposed by Stott and Alsac in 1974 [132].

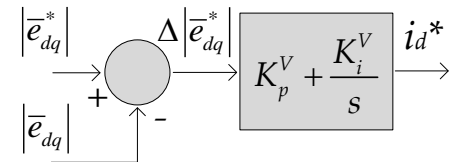


Figure 4.32: Alternating voltage outer controller diagram.

Since the dynamics of the reactive power channel are dependent on the impedance of the ac network, it is more difficult to perform a similar analysis to establish the controller parameters for the reactive channel and, therefore, its controllers are usually tuned via trial and error or based on the tuning of the active power controller [112].

Other outer controllers bandwidth

The previous analysis dealt with the achievable control bandwidth of the direct voltage controller, as this is certainly one the most important controllers in a VSC-HVdc system.

The dynamics of the remaining VSC-HVdc stations, directly controlling their active power instead of the MTdc network voltage, should not be made higher than the dynamics of the VSC-HVdc stations controlling the direct voltage [112]²⁶.

On the other hand, the reactive power channel controls the ac network voltage or directly the reactive power exchanged between the VSC-HVdc system and the connected ac system. As previously mentioned, it is difficult to perform a detailed analysis to determine a bandwidth for the reactive power controllers and a good compromise is to set it equal to the active power controller bandwidth.

Therefore, the bandwidth of the active power controller, α_p , and reactive power controllers, α_q , should be about the same or less than the bandwidth of the direct voltage controller, i.e.:

$$\begin{cases} \alpha_p \leq \alpha_{dc} \\ \alpha_q = \alpha_p \end{cases} \quad (4.48)$$

Table 4.1 gives an overview of the different VSC-HVdc controllers bandwidth and gains, and how to calculate them in per unit and in physical quantities.

Table 4.1: Bandwidth and control gains of the different VSC-HVdc controllers.

Controller	Bandwidth [rad/s]	Proportional gain		Integral Gain	
Inner-Current	α_c	$\alpha_c^{pu} l_T$	$\alpha_c L_T$	$\alpha_c^{pu} r_T$	$\alpha_c R_T$
Direct Voltage	$\alpha_{dc} \leq \frac{\alpha_c}{4}$	$k_p^w = \frac{\alpha_{dc}^{pu} c_{dc}}{2}$	$K_p^W = k_p^w \cdot \frac{I_b}{V_{dc_b}^2}$	$k_i^w = k_p^w \alpha_{dc}^{pu}$	$K_i^W = k_i^w \cdot \frac{I_b \omega_b}{V_{dc_b}^2}$
Active Power	$\alpha_p \leq \alpha_{dc}$	$k_p^p \leq k_p^w$	$K_p^P = k_p^p \cdot \frac{I_b}{S_b}$	$k_i^p \leq k_i^w$	$K_i^P = k_i^p \cdot \frac{I_b \omega_b}{S_b}$
Reactive Power	$\alpha_q = \alpha_p$	$k_p^q = k_p^p$	$K_p^Q = k_p^q \cdot \frac{I_b}{S_b}$	$k_i^q = k_i^p$	$K_i^Q = k_i^q \cdot \frac{I_b \omega_b}{S_b}$
AC Network Voltage	$\alpha_v = \alpha_q$	$k_p^v = k_p^q$	$K_p^V = k_p^v \cdot \frac{I_b}{V_b}$	$k_i^v = k_i^q$	$K_i^V = k_i^v \cdot \frac{I_b \omega_b}{V_b}$

²⁶ The reason is to allow sufficient time for the direct voltage-controlling stations to track power variations at least at the same pace as the other stations are changing their active power operating point, thus helping to maintain the MTdc network power balanced and the direct voltage under the establish limits.

4.4 MTdc Network Model

The transmission lines in a VSC-HVdc system can be either overhead (OHL), or via dc underground or submarine cables. Since, in comparison with the HVdc Classic system, the distances involved with VSC-HVdc systems are generally smaller, the use of dc cables is preferred with respect to OHL.

As power flow reversal in VSC-HVdc systems does not require the inversion of the direct voltage polarity, the dc cables can be designed to use extruded polymeric insulation as a substitute to the conventional oil-impregnated paper insulation. This results in lighter and more flexible cables, easier and quicker to install. These dc cables can withstand high forces, and repeated stresses, making them suitable for severe deep-water conditions [43].

When installed on land, the main issues for cable operation are the laying costs and the reliability, which is also of concern due to the high number of cable sections put together, each being 1 to 2 km long [104]. Present rated voltages on use in VSC-HVdc transmission schemes, with underground or submarine cables, are up to ± 320 kV in bipolar configurations (see Figure 4.34).

In the MTdc network model each dc cable is represented by a π -section circuit. Figure 4.33 shows a generic representation of a MTdc network for offshore wind energy integration.

Applying Kirchhoff laws to the network in Figure 4.33 – j nodes and i lines – yields²⁷:

$$\begin{cases} I_{Li} = \frac{V_{dci} - V_{dcj}}{R_i + sL_{dci}} \Leftrightarrow sI_{Li} = \frac{V_{dci}}{L_{dci}} - \frac{V_{dcj}}{L_{dci}} - I_{Li} \frac{R_{dci}}{L_{dci}} \\ sV_{dcj} = \frac{1}{C_{dcj}} \left(I_{dcj} - \sum_{i=1}^L I_{Mij} \cdot I_{Li} \right) \end{cases} \quad (4.49)$$

where;

I_{Li} is the current flowing through line i [A];

L_{dci} is inductance of MTdc line i [H];

C_{dcj} is the sum of all capacitances at node j [F] and;

I_{Mij} is MTdc network incidence matrix ij -th position.

The state-space matrix representation of the MTdc system is given

²⁷ In case of a bipolar HVdc configuration the nominal voltage is assumed to be balanced between the two poles.

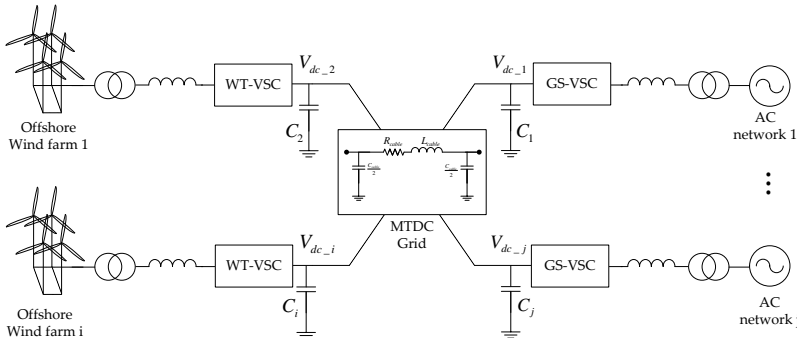


Figure 4.33: Generic representation of a MTdc grid

by:

$$\begin{cases} \dot{\mathbf{x}} = \mathbf{Ax} + \mathbf{Bu} \\ \mathbf{y} = \mathbf{Cx} + \mathbf{Du} \end{cases} \quad (4.50)$$

The state variable vector, \mathbf{x} , in (4.50), contains one equation per each energy-storage elements – capacitors and inductances – inside the MTdc network. Thus, the state vector is given by:

$$\mathbf{x} = \begin{bmatrix} V_{dc1} & \dots & V_{dcN} & I_{L1} & \dots & I_{L_L} \end{bmatrix}^T_{1 \times (N+L)} \quad (4.51)$$

N and L are, respectively, the total number of nodes and dc lines in the MTdc network.

The input vector, \mathbf{u} , is given by the net direct current, I_{dc} , injected at the VSC-HVdc terminals:

$$\mathbf{u} = \begin{bmatrix} I_{dc1} & \dots & I_{dcN} \end{bmatrix}^T_{1 \times N} \quad (4.52)$$

where;

$$I_{dcj} = P_{dcj} / V_{dcj} \text{ [A];}$$

P_{dcj} is the dc power inject by at node j [W] and;

V_{dcj} is the direct voltage at node j [V].

Independently of the MTdc grid connections, all the state-space model matrices, displayed in (4.50), can be obtained by using equations (4.53) to (4.56)²⁸.

The state matrix, \mathbf{A} , is composed out of 4 matrices, given as:

$$\mathbf{A} = \begin{bmatrix} \mathbf{A}^{11}_{N \times N} & \mathbf{A}^{12}_{N \times L} \\ \mathbf{A}^{21}_{L \times N} & \mathbf{A}^{22}_{L \times L} \end{bmatrix}_{(N+L) \times (N+L)} \quad (4.53)$$

$$\mathbf{A}^{11} = \mathbf{0}$$

$$\begin{aligned} \mathbf{A}^{12} &= - \left(\mathbf{I}_M \cdot \begin{bmatrix} \frac{1}{C_{dc1}} & 0 & \dots & 0 \\ 0 & \frac{1}{C_{dc2}} & \ddots & \vdots \\ \vdots & \ddots & \ddots & 0 \\ 0 & \dots & 0 & \frac{1}{C_{dcN}} \end{bmatrix} \right)^T \\ \mathbf{A}^{21} &= \begin{bmatrix} \frac{1}{L_{dc1}} & 0 & \dots & 0 \\ 0 & \frac{1}{L_{dc2}} & \ddots & \vdots \\ \vdots & \ddots & \ddots & 0 \\ 0 & \dots & 0 & \frac{1}{L_{dcL}} \end{bmatrix} \cdot \mathbf{I}_M \\ \mathbf{A}^{22} &= \begin{bmatrix} -\frac{R_{dc1}}{L_{dc1}} & 0 & \dots & 0 \\ 0 & -\frac{R_{dc2}}{L_{dc2}} & \ddots & \vdots \\ \vdots & \ddots & \ddots & 0 \\ 0 & \dots & 0 & -\frac{R_{dcL}}{L_{dcL}} \end{bmatrix} \end{aligned} \quad (4.54)$$

²⁸ The information on how the lines inside the MTdc network are actually connected is obtained from the incidence matrix $\mathbf{I}_M(L \times N)$.

On the other hand, the input matrix, \mathbf{B} , is constituted of only 2 sub-matrices:

$$\mathbf{B} = \begin{bmatrix} \mathbf{B}^{11}_{N \times N} \\ \mathbf{B}^{21}_{L \times N} \end{bmatrix}_{(N+L) \times N} \quad (4.55)$$

$$\mathbf{B}^{11} = \begin{bmatrix} \frac{1}{C_{dc1}} & 0 & \cdots & 0 \\ 0 & \frac{1}{C_{dc2}} & \ddots & \vdots \\ \vdots & \ddots & \ddots & 0 \\ 0 & \cdots & 0 & \frac{1}{C_{dcN}} \end{bmatrix}$$

$$\mathbf{B}^{21} = \mathbf{0}$$

The output matrix, \mathbf{C} ; and the feed-forward matrix, \mathbf{D} ; can be selected so as to obtain the desired output vector, \mathbf{y} . Here, the output vector is selected to coincide with the state vector, therefore:

$$\begin{cases} \mathbf{C} = \mathbf{I}_{(N+L) \times (N+L)} \\ \mathbf{D} = \mathbf{0}_{(N+L) \times N} \end{cases} \quad (4.56)$$

Figure 4.34 displays the evolution of extruded VSC-HVdc cables with regard to the direct voltage and power ratings. It also indicates the project and the year these cables were employed [133].

4.5 Wind Farm and AC Network Models

Wind farm model

In a dynamic model of a MTdc network for integration of offshore wind energy, the wind farms power output should be as realistic as possible. To accomplish that, the output of a wind turbine can be combined for different average wind speeds and time delays, as illustrated in Figure 4.35, to obtain the spatial smoothing effect of the complete wind farm.

Figure 4.35 shows the wind farm layout, with the undisturbed wind speed, $V_w(t)$, and average speed, V_w . The rotor wakes decreases the average wind speed row after row, while the wind direction is kept uniform. The applied delay times are inversely related to the average wind speed, which results in sufficiently low correlation between the time series [134].

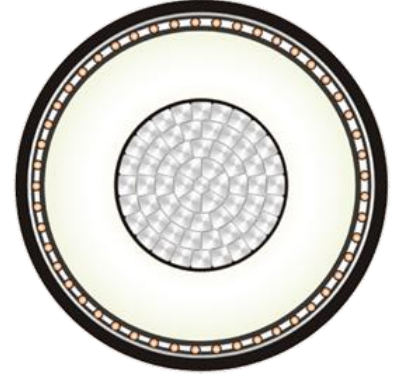
The wind farm models aggregates a limited number of wind turbines to match the nominal power of the wind farm. The modelled wind turbines use permanent magnet synchronous generators (PMSG) with a full-rated back-to-back voltage-source converter. The collection grid is represented by a lumped model with a single cable and the farm is connected to the MTdc grid through a VSC-HVdc station.



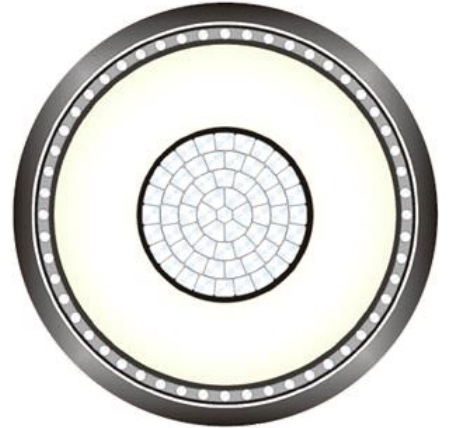
(a) 2000, Directlink, 354 km, ± 80 kV, 60 MW



(b) 2001, Murraylink, 360 km, ± 150 kV, 220 MW



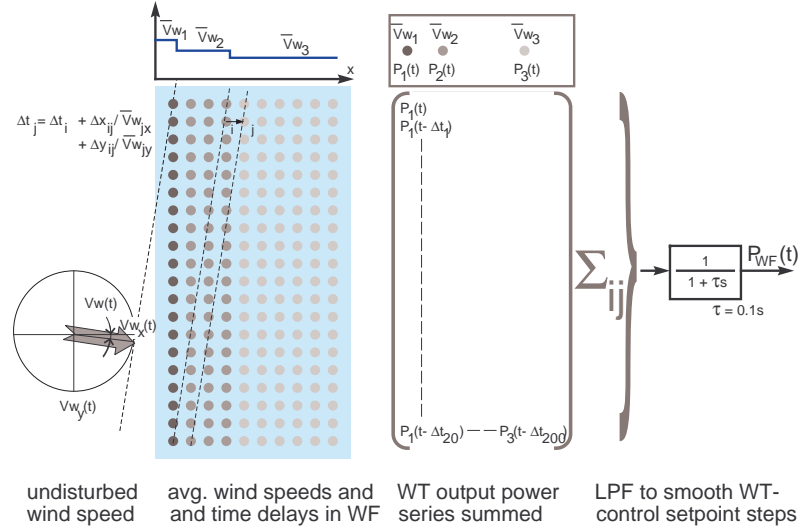
(c) 2004, Estlink, 210 km, ± 150 kV, 350 MW



(d) 2010, DolWin, 165 km, ± 320 kV, 800 MW

Figure 4.34: Evolution of VSC-HVdc cable transmission capacity [133].

Figure 4.35: Wind farm model to smooth the output power of a wind turbine.



Wind turbine model

One of the goals inside the NSTG project is to achieve the maximum aerodynamic efficiency as possible over a wide range of wind speeds. Although wind turbines with doubly-fed induction generators (DFIG) still constitutes the most used and marketed wind turbine type, turbines with PMSG offer a higher range of dynamic speed control, a higher torque to weight ratio, and higher efficiency due to the internal magnets [135]. Hence, the latter will likely be employed in offshore wind farms.

The control strategy used for the PMSG wind turbine is the field oriented control, where the permanent-magnet flux is aligned with the rotating frame d-axis so the q-axis machine flux is zero ($\bar{\lambda}_{mq} = 0$) [136,137].

The turbine speed is variable and controlled to always yield the maximum efficiency. The inner-current controller of the wind turbine VSC guarantees the rotor flux is aligned with the d-axis of the rotating reference frame by imposing $i_{sd}^* = 0$, while the q-axis current reference, i_{sq}^* , will come from the speed controller.

The speed controller model is based on the generator shaft dynamics, and on the fact the q-axis current will control the electric torque. Below the wind turbine rated speed, the PMSG rotor speed reference is optimised by controlling the generator torque. Additionally, above rated wind speeds, the aerodynamic power is also controlled by changing the blade pitch angle. More details about wind turbine controllers can be found in [137,138].

Modern wind turbines, with relatively high power ratings, are now built as variable-speed pitch-controlled turbines whilst in the past most wind turbines were fixed-speed stall-controlled units [139].

The electric generators inside wind turbines can be connected to the turbine shaft through a staged gearbox or be directly driven. As far as the generator type is concerned, wind turbines can be classified

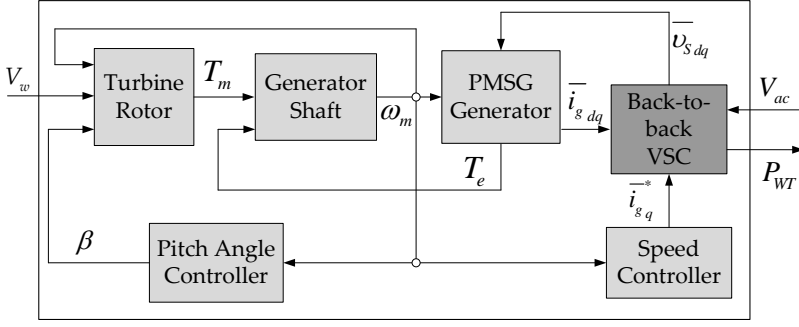


Figure 4.36: Modular representation of variable-speed PMSG wind turbines.

as: squirrel-cage induction generators (SCIG); doubly-fed induction generators and permanent-magnet synchronous generators.

The turbine model, shown in Figure 4.36, is based on the following mathematical expression [140]:

$$P_m = \frac{T_m}{\omega_m} = \frac{\rho}{2} A_r \omega_w^3 C_p(\lambda, \beta) \quad (4.57)$$

where;

P_m is the wind turbine mechanical power [W];

V_w is the wind speed [m/s] and;

A_r is the wind turbine rotor area [m²].

The power coefficient $C_p(\lambda, \beta)$ is calculated as [140]:

$$\begin{cases} C_p(\lambda, \beta) = 0.22 \left(\frac{116}{\lambda_i} - 0.4\beta - 5 \right) e^{\frac{-12.5}{\lambda_i}} \\ \frac{1}{\lambda_i} = \frac{1}{\lambda + 0.08\beta} - \frac{0.035}{\beta^3 + 1} \end{cases} \quad (4.58)$$

where;

λ wind turbine tip speed ratio [pu] and;

β is a function of the wind turbine pitch angle [rad].

PMSG Model

The permanent-magnet synchronous generator model is based on the machine magnetic and electric equations written in the rotating (dq) frame [140]:

$$\begin{cases} \bar{\lambda}_{dq} = L_{eq} \bar{i}_{sdq} + \bar{\lambda}_{mdq} \\ \bar{v}_{sdq} = R_s \bar{i}_{sdq} + \frac{d\bar{\lambda}_{dq}}{dt} + j\omega_r \bar{\lambda}_{dq} \end{cases} \quad (4.59)$$

where;

$\bar{\lambda}_{dq}$ is the PMSG flux in the rotating frame [Wb];

$L_{eq} = L_s + L_\sigma$ is the sum of the stator windings self-inductance and dispersed inductance [H];

\bar{i}_{sdq} is PMSG stator current in the rotating frame [A];

$\bar{\lambda}_{mdq}$ is permanent magnet flux in the rotating frame [Wb];

\bar{v}_{sdq} is the PMSG stator voltage in the rotating frame [V];

R_s is the PMSG stator resistance [Ω] and;

ω_r is the PMSG rotor speed [rad/s].

The PMSG control strategy used is the field oriented control, where the permanent-magnet flux, $\bar{\lambda}_{mdq}$, is aligned with the d-axis of the rotating frame so that $\bar{\lambda}_{md} = \lambda_m$ and $\bar{\lambda}_{mq} = 0$. Substituting these values of $\bar{\lambda}_{mdq}$ into (4.59) and solving for the current derivatives yields the PMSG state-space equations:

$$\begin{cases} L_{eq} \frac{d}{dt} (i_{sd}) = v_{sd} - R_s i_{sd} + \omega_r L_{eq} i_{sq} \\ L_{eq} \frac{d}{dt} (i_{sq}) = v_{sq} - R_s i_{sq} - \omega_r L_{eq} i_{sd} - \omega_r \lambda_m \end{cases} \quad (4.60)$$

As was the case for the VSC-HVdc state-space equations, the poles of (4.60) are given by the roots of $(s + R_s/L_{eq})^2 + \omega_r^2 = 0$, which are oscillatory and progressively less damped as ω_r increases.

The solution is once more to feed back the stator currents through a current controller closing the current loop, a function that is accomplished by the current controller of the back-to-back converter in the wind turbine [137]. The current feedback is also important to guarantee that the rotor flux is aligned with the d-axis of the rotating reference frame by imposing $i_{sd}^* = 0$, while the q-axis current reference, i_{sq}^* , will come from the speed controller.

Speed Controller Model

The speed controller model is based on the generator shaft equation:

$$\frac{d}{dt} \omega_r = J(T_e - T_m) \quad (4.61)$$

where;

T_e is the PMSG electric torque [Nm] and;

T_m is the PMSG mechanical torque [Nm].

Since $i_{sd} \approx i_{sd}^* = 0$, the q-axis current controls the electric torque:

$$T_e = \bar{\lambda}_{dq} \times \bar{i}_{sdq} = \lambda_m i_{sq} \quad (4.62)$$

Thus, using a PI regulator for the speed controller, the reference torque can be calculated as [141]:

$$T_e^* = i_{sq}^* \lambda_m = \left(K_p^s + \frac{K_i^s}{s} \right) (\omega_r - \omega_r^*) \quad (4.63)$$

where;

T_e^* is the PMSG electric torque reference [Nm];

i_{sdq}^* is the PMSG stator current reference in the rotating frame [A];

ω_r^* is the PMSG rotor speed reference [rad/s];

K_p^s is the PMSG speed controller proportional gain [rad/s/Nm] and;

K_i^s is the PMSG speed controller integral gain [rad/s²/Nm];

AC Network model

The ac grids are modelled as an infinite bus behind a short-circuit series impedance. The ac grids considered in the thesis do not have

other loads or generation units connected to them and their short-circuit series impedance is calculated based on the network short-circuit power and the rated voltage according to IEC-60909-0:

$$Z_{cc} = V_b^2 / S_k \quad (4.64)$$

where;

Z_{cc} is the ac network short-circuit impedance [Ω] and;

S_k is the ac network short-circuit power [VA].

4.6 Conclusion

To derive the complete dynamic model of a MTdc network it is first necessary to independently derive the mathematical equations driving each of its modules. Afterwards, to create a combined dynamic model, it is necessary to understand what are the physical quantities connecting each module and to identify the point where they will interact.

As discussed in Chapter 3, the knowledge of how the system modules interact is essential in a system which uses modular architecture since it allows the system designers to clearly establish the performance criteria of each module and of the complete system.

The voltage-source converter is definitively the most important component inside multi-terminal dc networks. The dynamic behaviour of multi-terminal dc networks greatly depends on the dynamic behaviour of its converters, on the same way that the dynamic behaviour of ac networks depends mostly on the dynamic behaviour of its synchronous generators.

The performance of voltage-source converters – mainly dictated by their achievable control bandwidths – were calculated and the control parameters for a stable closed-loop operation of the whole system were given. For a voltage-source converter, the obtainable control bandwidth is restricted by the converter switching and sampling frequencies. As a result, the VSC control parameters – calculated via the derived transfer functions – have to take the system physical constraints into consideration.

Finally, the multi-terminal dc network model generated in this chapter is of extreme importance for the subsequent chapters in the thesis. In Chapter 5, the dynamic models are used to compare different direct voltage control strategies. In Chapter 6, they are used to develop a novel control strategy for MTdc networks. On the other hand, in Chapter 7 the dynamic models are used to assess the fault behaviour of MTdc networks during ac and dc contingencies. In Chapter 8, the dynamic models are linearised and represented via state-space matrices, which allows to study stability by looking at the location of the system eigenvalues. Lastly, in Chapter 9, the dynamic models are used to control real voltage-source converters in a low-voltage multi-terminal dc network experimental setup.

5

Control of MTdc Networks

Power is nothing without control.

Pirelli & C. SpA

Two of the main challenges facing the development of MTdc networks are power flow control and dynamic performance, which were introduced, respectively, in Chapter 3 and Chapter 4. The main goal of this chapter is to identify the shortcomings of the most commonly used methods for controlling the direct voltage of MTdc networks, namely: droop control, ratio control, priority control and the voltage margin control method. To achieve this goal, the dynamic models previously developed in Chapter 4 are here used to compare these methods according to four different performance criteria: their dynamic response, expandability, communication needs and flexibility, i.e. their ability to steer the power flow inside the MTdc network. The chapter is structured as follows: first, each method is presented, and their control implementation is given. Afterwards, a case study involving a MTdc network with four terminals – two onshore, responsible for the control of the MTdc network direct voltage, and two offshore, responsible for the generation – is used to compare the methods. Finally, conclusions are made based on the results from the dynamic simulations.

- 5.1. MTdc Network Control Principle
- 5.2. Droop Control
- 5.3. Ratio Control
- 5.4. Priority Control
- 5.5. Voltage Margin Method Control
- 5.6. Case Study
- 5.7. Conclusion

This chapter is based on the following publication:

R. Teixeira Pinto, S. Rodrigues, P. Bauer, and J. Pierik, "Description and Comparison of DC Voltage Control Strategies for Offshore MTDC Networks: Steady-State and Fault Analysis," *European Power Electronics Journal*, vol. 22, no. 4, pp. 13-21, 2013.

5.1 MTdc Network Control Principle

Inside a VSC-MTdc network, direct voltage control is certainly one of the most important tasks given to VSC-HVdc stations. A well-controlled direct voltage on a HVdc grid requires a balanced power flow between all the interconnected nodes [142]. If the dc system voltage starts to increase excessively, it may trigger protective equipment, such as dump resistors [143,144]. On the other hand, a large direct voltage drop might generate nonlinear phenomena, creating difficulties for the control systems, limiting the capability of the reactive power and ac system voltage controllers [116].

In point-to-point HVdc transmission systems the control is typically arranged so that one terminal controls the dc-link voltage while the other operates in current – or power – regulation mode. This control philosophy of having only one converter controlling the direct voltage can be extended to MTdc networks. However, disregarding losses, the net sum of the active power of all the converters operating in current regulation mode has to be, at all times, lower than the maximum ratings of the direct-voltage controlling station. Mathematically, this control strategy for MTdc networks is translated as:

$$P_{Vdc}^{\max}(t) \geq \sum_{i=1}^{N-1} P_{ldc}^i(t) \quad (5.1)$$

where;

$P_{Vdc}^{\max}(t)$ is the instantaneous maximum active power of the N-th VSC controlling the dc system voltage [VA] and;

$P_{ldc}^i(t)$ is the instantaneous active power of the i-th VSC terminal operating in current regulation mode [VA]¹.

From (5.1) it becomes clear that as MTdc network grows it is increasingly difficult to assure power balance by having only one terminal responsible for the direct voltage regulation. Thus, for large MTdc networks, controlling the voltage at a single terminal is not desirable. Therefore, for its successful development and operation, MTdc networks will require a control strategy capable of sharing the direct voltage control among more than one network node².

In the next sections the four most common direct voltage control methods – which share direct voltage control – for VSC-MTdc networks are presented and discussed, namely: droop control, ratio control, priority control and voltage margin method control [145–147].

5.2 Droop Control

The droop control strategy was firstly proposed for controlling CSC-MTdc networks; however, this method can also be applied for VSC-MTdc networks [129,148].

The droop control scheme for MTdc networks works similarly to the one implemented in traditional ac power systems, where the

¹ $P_{Vdc}^{\max}(t)$ is a function of time because a VSC has limited current capability. If, at a certain given time, t , the converter has to provide reactive power to its ac network, then the converter active power capability will be lower than its rated apparent power. This effect is further discussed in Section 7.1 when grid code requirements are analysed.

² In addition, if an outage would affect the only voltage controlling station, direct voltage control would be lost until somehow transferred – e.g. after a defined overvoltage threshold – to another node in the network. However, this is not desirable since the fast nature of dc phenomena could trigger protection equipment, within only a few cycles of the ac network.

load dependent frequency variation is used as an input signal for the control system to adjust the generated power to meet demand at all times [130]. In MTdc networks, the control employs the droop mechanism to regulate the direct voltage within the system by adjusting the converter current so that power balance is guaranteed [130]. Figure 5.1 shows the characteristic curve and block diagram of droop control strategy.

Although the droop regulator provides the inner-current controller q-axis reference, i_q^* , it actually tries to regulate the VSC direct current:

$$\begin{cases} p_{ac} = e_d i_d + e_q i_q \approx p_{dc} = v_{dc} i_{dc} \\ \text{if } e_d \approx 0 \text{ pu; } e_q \approx 1 \text{ pu and } v_{dc} \approx 1 \text{ pu, then} \\ i_{dc} \approx i_q \end{cases} \quad (5.2)$$

The droop control can be seen as a proportional control in which the gain, k_p^w , is equal the inverse of the characteristic curve slope, i.e.:

$$k_p^w = \frac{\Delta i_{dc}}{\Delta v_{dc}} \quad (5.3)$$

As discussed in Section 4.3, there is a maximum value the proportional gain can assume before the direct voltage controller response becomes oscillatory. Moreover, since droop control is usually made proportional to the direct voltage (and not its squared value), the control response is non-linear and dependent on the operating point.

Section 3.3 introduced the fact that dc networks will require rules in a similar way in which ac grids operate with regard to the transmission system operator grid code. Examples of design rules for MTdc networks included the direct voltage level, the size and topology of each HVdc station, protection philosophy, control strategy and the power transfer capability of the dc cables.

Additionally, it can also include parameters of the direct voltage control strategy, such as v_{dc}^{max} , v_{dc}^0 and v_{dc}^{min} for the droop control characteristic curve shown in Figure 5.1 (a).

Extending the droop control method to MTdc networks with more terminals should be straightforward and the synchronisation of the several VSC stations would happen without the need for fast communication [149]³.

³ If the network direct voltage starts increasing, there is power surplus in the dc system and the regulating stations should increase inversion. On the other hand, as the voltage starts to decrease, power is lacking in the dc system and the regulating stations should increase rectification (see Figure 5.1 (a)).

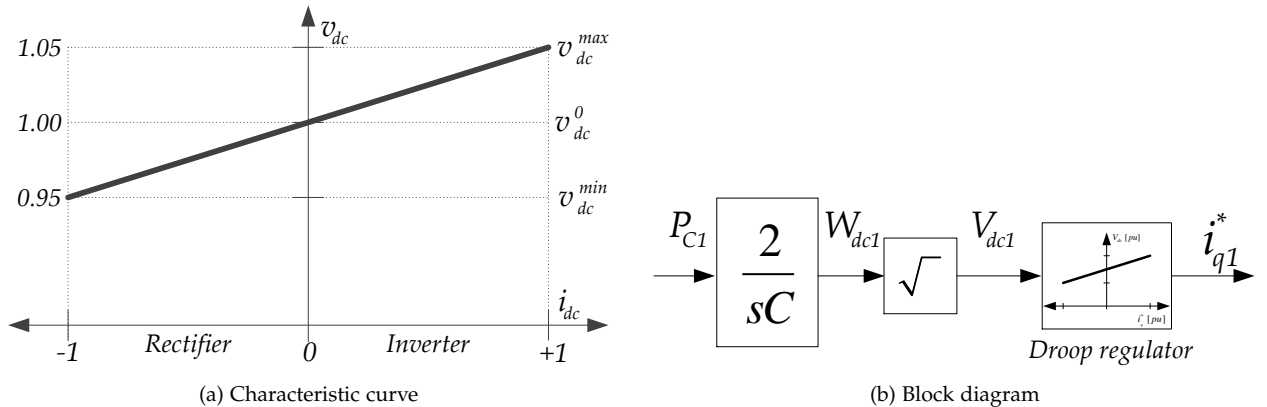


Figure 5.1: Droop control strategy.

⁴ Recent attempts have been made to modify the droop control strategy to improve its flexibility for controlling the power flow in MTdc networks [153,154]. However, they were not analysed in this thesis.

However, the main downside of droop control is the fact that power flow control is limited [150,151]. For instance, in an offshore grid, steering the power produced by the wind farms to a particular node in the network would not be possible without communication [148,152]⁴.

5.3 Ratio Control

The ratio control is a modification of the droop control to address the difficulty of steering the power flow in the network. In this control strategy, a power ratio is established between two or more dc system voltage controlling stations so that the converters share the generated power accordingly to the desired ratio [155,156].

The difference between the ratio controller and the droop controller is that, by varying the slope of the droop characteristic, a system operator can vary the power ratio between the terminals in the transmission system. Figure 5.2 shows the characteristic curve and block diagram of the ratio control strategy between two voltage-source converters.

Under steady-state operation, as V_{dc} is close to the nominal value, it is possible to assume that the active power depends on the ratio between the converter currents, i.e [155]:

$$\frac{P_{dc1}}{P_{dc2}} = n \approx \frac{I_{dc1}}{I_{dc2}} \quad (5.4)$$

Assuming that both converters are directly connected by dc cables yields⁵:

$$V_{dc2} - V_{dc1} = R_1 I_{dc1} - R_2 I_{dc2} \quad (5.5)$$

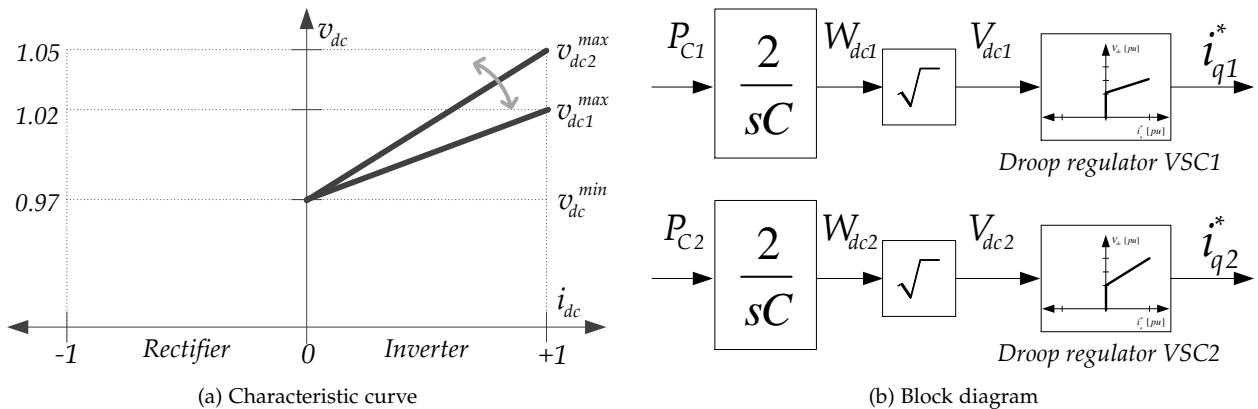
where;

R_{dc1} and R_{dc2} are respectively the dc cable resistances of VSC1 and VSC2 to the point of common coupling in the dc network [Ω].

Based on Figure 5.2 (a), the dc droop characteristics of both VSC

⁵ If the converters are not directly connect then relating V_{dc1} to V_{dc2} has to be done via the MTdc network admittance matrix which further increases the method complexity.

Figure 5.2: Ratio control strategy.



stations are calculated as:

$$\begin{cases} i_{dc1} = k_{p1}^w \Delta v_{dc1} = k_{p1}^w (v_{dc1} - v_{dc1}^{min}) \\ i_{dc2} = k_{p2}^w \Delta v_{dc2} = k_{p2}^w (v_{dc2} - v_{dc2}^{min}) \end{cases} \quad (5.6)$$

If $v_{dc}^{min} = v_{dc1}^{min} = v_{dc2}^{min}$ it is possible to re-write (5.5) as:

$$\begin{cases} (v_{dc2} - v_{dc}^{min}) - (v_{dc1} - v_{dc}^{min}) = r_{dc1} i_{dc1} - r_{dc2} i_{dc2} \\ \frac{i_{dc2}}{k_{p2}^w} - \frac{i_{dc1}}{k_{p1}^w} = r_{dc1} i_{dc1} - r_{dc2} i_{dc2} \end{cases} \quad (5.7)$$

In conclusion, to guarantee that the power ration between the two converters is equal the one established by the system operator, the relationship between the two droop characteristics must be such that:

$$\begin{cases} \frac{i_{dc1}}{i_{dc2}} = \frac{r_{dc2} + 1/k_{p2}^w}{r_{dc1} + 1/k_{p1}^w} \\ \Rightarrow k_{p2}^w = \frac{1}{n \left(1/k_{p1}^w + r_{dc1} \right) - r_{dc2}} \end{cases} \quad (5.8)$$

The analysis of (5.8) shows that one of the main disadvantages of the ratio control strategy is its expandability. It might be difficult, or even impossible, to find an analytic expression that correctly correlates the power ratio for the case where more than two stations are controlling the direct voltage inside the MTdc network⁶.

Finally, another disadvantage of this method is that it may require communication, in case the system operator decides to perform different power ratios, since both converters droop characteristics must be known [156,157].

5.4 Priority Control

In the priority control strategy, one VSC terminal will have precedence over the other terminals for the power being injected into the MTdc network⁷. This control strategy is accomplished by combination of two different direct voltage controllers: PI and proportional (or droop) controllers. [147,158].

The first terminal – the one with the precedence – will control the MTdc network direct voltage by means of a PI controller until it reaches its rated capacity or a maximum power reference established by system operators. On the other hand, a direct voltage droop controller (proportional controller) is provided to the other VSC terminals⁸. Figure 5.3 displays the characteristic curve and block diagram of the priority control strategy between two converters.

The method works as follows: the first terminal controls the MTdc network voltage through a PI controller – the flat characteristic curve shown Figure 5.3 (a) – until its rated power capacity is reached. After that, as a consequence of the momentary power unbalance, the direct voltage inside the MTdc networks will increase until it surpasses v_{dc2}^{min} , after which the second terminal starts transmitting power.

⁶ In addition, the analytic expression shown in (5.8) depends on the resistance of the dc cables, which may further affect the method accuracy [155].

⁷ In the case of the North Sea Transnational grid this translates into precedence over the power produced by the offshore wind farms.

⁸ The remaining converters only starts receiving – or transmitting – power once the first terminal has reached its limit, hence the name of this control strategy.

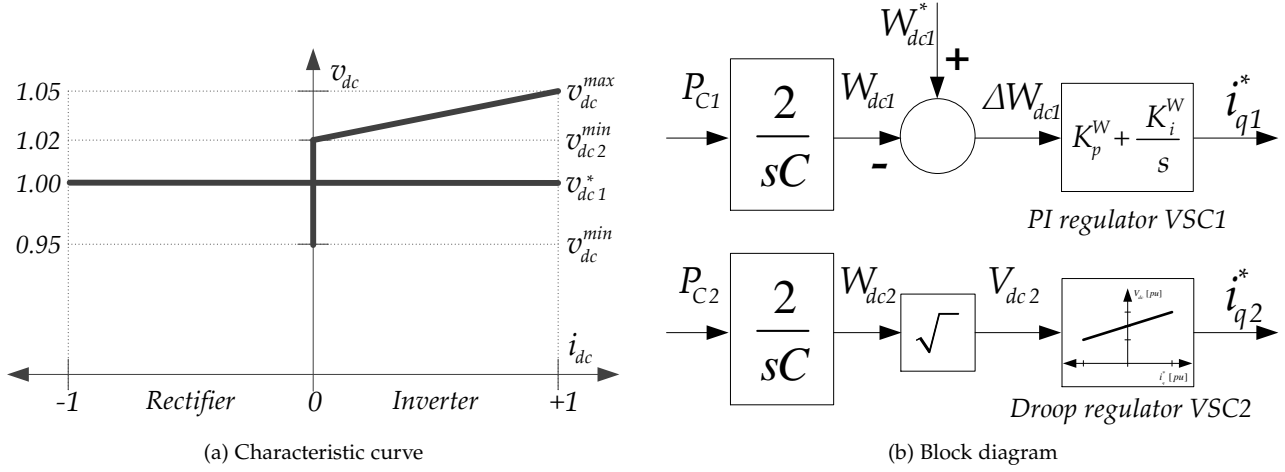


Figure 5.3: Priority control strategy.

As was the case for the droop and ratio control strategy, the choice of the control parameters – e.g. v_{dc2}^{min} and v_{dc}^{max} in Figure 5.3 (a) – has to take into account the system design rules, such as the MTdc network voltage ratings and the capacity of the dc transmission cables.

The priority control strategy is interesting for small MTdc networks. For instance, in a small offshore MTdc grid, where a specific country wishes to have precedence over the power produced by its wind farms and is willing to sell the exceeding power to neighbouring countries [147]. However, it is not clear how this control method can be extended to larger MTdc networks. In addition, operation of MTdc networks by assigning priority to certain terminals is not effective as it may generate a large number of idle converters.

5.5 Voltage Margin Method Control

The Voltage Margin Method (VMM) to control VSC-HVdc systems was first proposed by Tokiwa et al. in 1993 [159] and, in 1999, Nakajima and Irokawa proposed to use it to control a 3-terminal back-to-back MVdc scheme known as the Shin-Shinano substation, located in Japan [160,161].

In this control strategy, each converter station in a MTdc network is given a marginally offset direct voltage reference, called margin. Similarly to the current margin method for CSC-MTdc networks [60], the voltage margin is defined as the direct voltage reference difference between the two VSC terminals⁹. The voltage margin method controller is usually implemented as a single-stage or double-stage controller; both controllers are explained next.

Single-Stage VMM Controller

The characteristic curve and block diagram of a single-stage voltage margin method controller are shown in Figure 5.4, where point A represents the dc system operating point [160,161].

⁹ The voltage margin method control strategy is dual to the current margin method proposed for controlling CSC-MTdc networks [37,60]

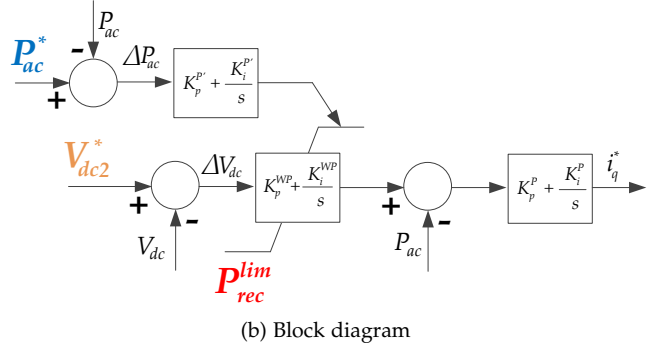
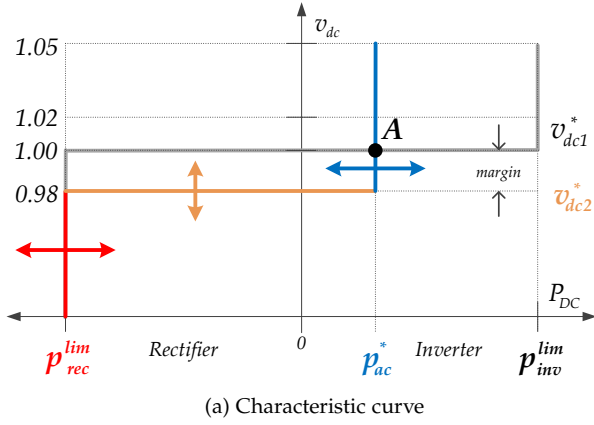


Figure 5.4: Single-Stage Voltage Margin Method control strategy.

The method works as follows: a first VSC receives a single PI regulator set to v_{dc1}^* , as was the case with the priority control strategy (see Figure 5.3 and Figure 5.4). The VMM controller – given to a second VSC – consists of three PI regulators whose goal is to output the active-current reference, i_q^* , for the ICC, presented in Section 4.3 [159,160].

The first PI regulator receives an active power reference, p_{ac}^* – see Figure 5.4 – and outputs an upper limit power reference to the second PI regulator. This upper power limit is then fed to the second PI regulator, which also receives a direct voltage reference, v_{dc2}^* , and outputs a power reference to the last PI regulator; the one responsible for finally generating the active-current reference.

The second PI regulator also receives a lower limit power reference, p_{rec}^{lim} – see Figure 5.4 – which limits the voltage-source converter operation as a rectifier. In the voltage margin control method, the VSC lower and upper active power references are adjustable and may be established by the system operator directly or via a remote dispatch centre if communication is employed. By adjusting the lower and upper active power limits to the same value, the converter can perform constant power control and therefore, act as a constant load [159].

In a MTdc network, the voltage margin method control strategy may be implemented in more than one VSC-HVdc station. The direct voltage reference value of each converter will differ by a voltage margin, so that control of the direct voltage inside the MTdc network is transferred from one station to another in a cascading effect. The direct voltage will be controlled first by the VSC-HVdc station with the lowest voltage reference and will be controlled last by the VSC-HVdc station with the highest voltage reference.

An example of two VSC-HVdc systems both using VMM controllers is shown in Figure 5.5, where point A denotes the MTdc network operating point. The first VSC controls its active power to p_{rec1}^{lim} , whereas the second converter controls the dc network voltage at V_{dc2}^* ¹⁰. The MTdc network operating point, point A in Figure 5.5, can be moved by adjusting the references of both converters accordingly.

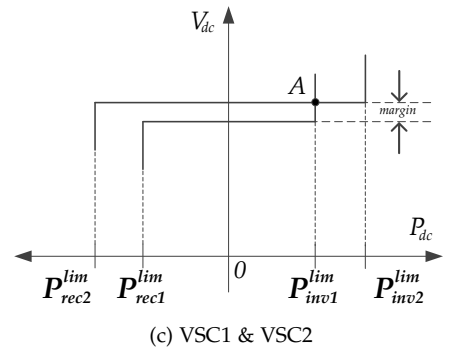
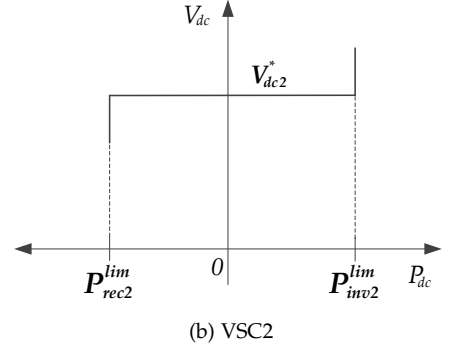
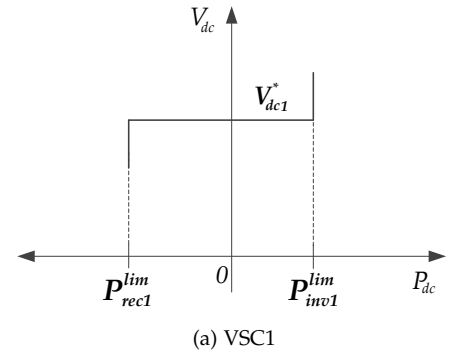


Figure 5.5: Voltage Margin Method characteristics for two different VSC-HVdc stations.

¹⁰ This operational mode is known as fixed power sharing since the first station receives a fixed amount of active power.

As an example, if the voltage reference of VSC1 is made higher than that of VSC2, point A will move to the right of the $P_{dc}-V_{dc}$ plane and, as a result, the first converter will reverse its power flow and perform inversion rather than rectification. However, to perform power schemes other than fixed power sharing, a more versatile and robust voltage margin method with more than a single stage is needed.

Double-Stage VMM Controller

The double-stage scheme is more suited for multi-terminal dc systems, as it increases the control flexibility of the VSC-HVdc terminals in comparison with the single-stage scheme. The characteristic curve and block diagram of a double-stage voltage margin method controller are shown in Figure 5.6.

Once again, to explain how the method works, a first VSC receives a single PI regulator set to v_{dc1}^* – see Figure 5.6 – whereas the voltage margin method controller is given to a second VSC. As shown in Figure 5.6 (b), in comparison with the single-stage VMM controller, the double-stage one contains an additional PI regulator [160,161].

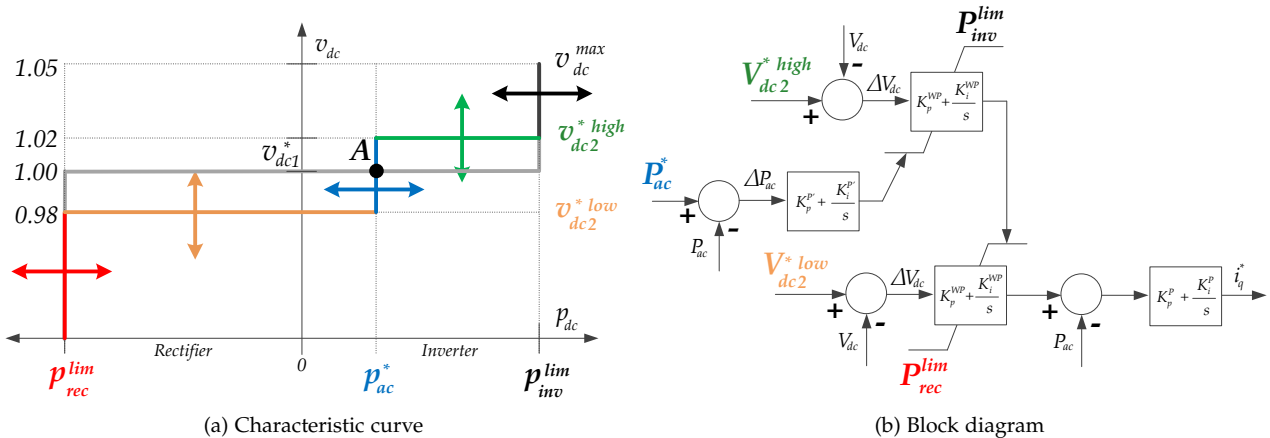
The two-stage VMM controller works as follows: between the converter limit as a rectifier, p_{rec}^{lim} , and the active power reference power, p_{ac}^* , the converter will try to control the direct voltage at v_{dc2}^{*low} by means of the lower direct voltage PI regulator.

If the network voltage is within v_{dc2}^{*low} and v_{dc2}^{*high} , the converter will control its active power to p_{ac}^* by means of the active power PI regulator. Finally, if the MTdc network voltage increases in the range between p_{ac}^* and the converter limit as an inverter p_{inv}^{lim} , the converter will control the direct voltage at v_{dc2}^{*high} by means of the upper direct voltage PI regulator.

The voltage margin method is a versatile control strategy and it is the only one, amongst the analysed control strategies, capable of performing three different active power dispatch schemes: fixed, priority and proportional power sharing [147]¹¹.

¹¹ The other control strategies analysed so far from Section 5.2 up to Section 5.4 were: droop, ratio and priority control strategy.

Figure 5.6: Double-Stage Voltage Margin Method control strategy.



Fixed power sharing

To perform a fixed power sharing dispatch scheme, the converters characteristic curves have to be set by the system operator as presented in Figure 5.7. With such VMM controllers, the first converter will be responsible for controlling the direct voltage inside the MTdc network, whereas the second converter will act as a constant load transmitting a given amount of active power, P_{ac2}^* . For this dispatch scheme to work, it is important that the lower active power limits, P_{rec}^{lim} , and upper active power limits, P_{inv}^{lim} , of both converter are made equal.

Proportional power sharing

A proportional power sharing dispatch scheme can be established if the transmission system operator measures the power being generated in the MTdc network and then calculates the amount of power that each converter will receive according to the defined ratio. The characteristic curves of two stations performing proportional power sharing are shown in Figure 5.8.

The station with the lowest direct voltage reference adjust its power reference, P_{ac2}^* , whereas the other converter controls the MTdc network voltage at V_{dc1}^* . For this dispatch scheme to work, it is important that the upper active power limits, P_{inv}^{lim} , of both converter are made equal.

Even if only two voltage source converters are used, this dispatch scheme will require communication between the converter stations and a system operator supervisory control.

Priority power sharing

The characteristic curves for two converters performing priority power sharing are shown in Figure 5.9, where priority is given to the second converter. Once the prioritised converter reaches its rectifying, P_{rec2}^{lim} , or inversion limits, P_{inv2}^{lim} , the direct voltage control will be passed onto the first converter, which will regulate the MTdc network voltage either at V_{dc1}^{low} or V_{dc1}^{high} . The second converter will then control its active power. As a result, the MTdc network operating point will move from A to either A' or A''.

Drawbacks

The voltage margin method has two main drawbacks: because of its controller architecture, the dynamic response is slower than other methods and only one converter is controlling the MTdc system voltage at a given time [146]¹².

Additionally, with a limited direct voltage operating range, e.g. $\pm 10\%$ the nominal voltage, the maximum number of VSC terminals that can be controlled by the voltage margin method may be limited. That is to avoid adverse interaction between the controls of each terminal generated by possibly too low voltage margins¹³.

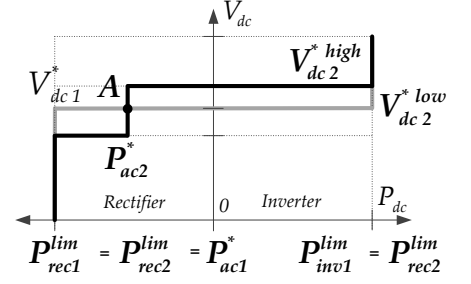


Figure 5.7: Voltage margin method characteristic curves for fixed power sharing dispatch.

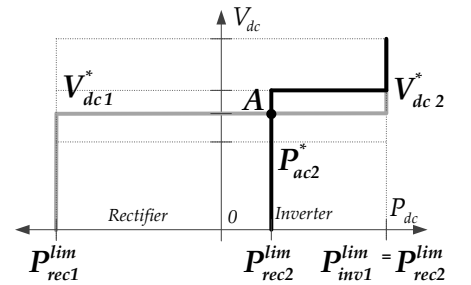


Figure 5.8: Voltage margin method characteristic curves for proportional power sharing dispatch.

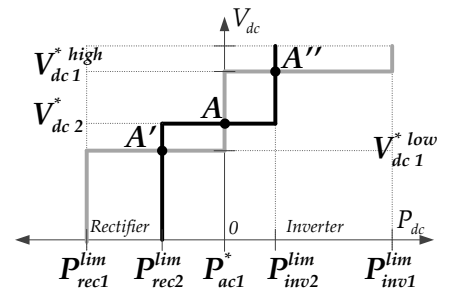


Figure 5.9: Voltage margin method characteristic curves for priority power sharing dispatch.

¹² This will be shown next in the case study presented in Section 5.6.

¹³ Nevertheless, extending the voltage margin method to larger MTdc networks with multiple terminals should be easier to accomplish than for the ratio or priority controllers.

5.6 Case Study

Table 5.1: Order of events in the studied 4-node MTdc network.

Time [s]	P_{OWF1} [pu]	P_{OWF2} [pu]
0.00	0.00	0.00
0.50	0.50	0.00
1.00	0.50	0.40
1.50	0.80	0.40
2.00	0.80	0.80
3.00	0.50	0.40
5.00	0.50	0.40

¹⁴ When a fault happens offshore, the power being transmitted is reduced and the stress is on the wind farm turbines rather than on the onshore VSC terminals [136,162].

A MTdc network consisting of four nodes – two ac grids and two wind farms – is studied to test the four different schemes which were analysed up to now. The network layout is displayed in Figure 5.10.

The ac grids and the wind farms are modelled as ideal voltage sources behind impedances. The system base direct voltage is 400 kV (± 200 kV) and the system base power is 500 MVA.

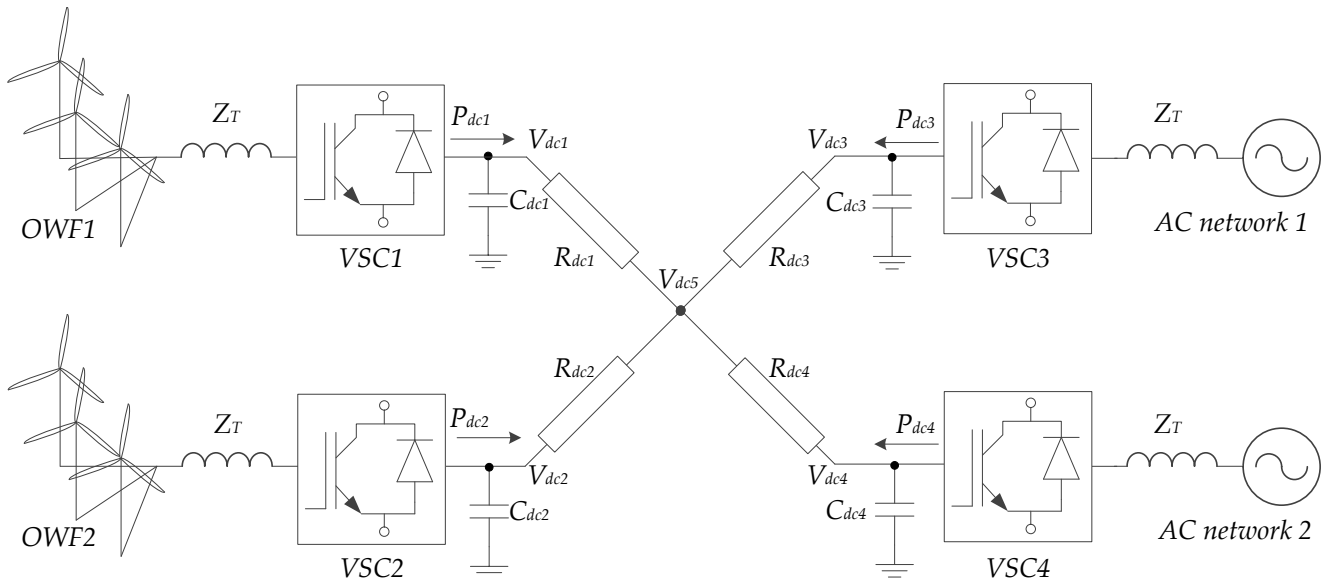
In the case study, the offshore wind farms (OWF) are considered to be producing power according to the values displayed in Table 5.1. The rated parameters of the studied MTdc network are given in Table 5.2.

Inside MTdc networks, onshore three-phase faults will be much more demanding for the remaining direct voltage controlling stations than offshore faults¹⁴. When a fault happens in a VSC which is controlling the MTdc network voltage, the remaining stations have to promptly absorb the lost power to maintain the dc system stability.

If the total produced power is greater than the combined capacity of the remaining onshore converters, direct voltage control becomes impossible. In these situations, the power from the offshore wind farms have to be curtailed either through fast power reduction methods or through the use of dc choppers installed in the VSC-HVdc stations [148] (see Figure 4.2).

As onshore faults are more demanding, a solid three-phase fault is simulated on onshore ac grid 1. The fault starts at simulation time $t = 3.5$ s and is cleared 200 ms later. The simulation results are shown, for the different control strategies, from Figure 5.11 until Figure 5.14.

Figure 5.10: Layout of the analysed radial MTdc network with 4 terminals.



Parameter	Value	Parameter	Value
AC Grid Power (S_k)	3500 MVA	AC Grid Voltage (E_L)	220 kV
OWF Power (P_{ac}^{owf})	500 MW	OWF Voltage (V_{owf})	33 kV
VSC Power (S_{vsc})	500 MVA	VSC Voltage (V_c)	180 kV
Trafo Impedance (z_t)	$0.005 + j0.10$ pu	Phase Reactor (z_c)	$0.003 + j0.15$ pu
MTdc Voltage (V_{dc})	400 kV (± 200) kV	VSC Capacitor (C_{dc})	75 μ F
Cable Resistance (r_{dc})	0.200 Ω /km	Cable Inductance (l_{dc})	19.10 mH/km
Cable Capacitance (c_c)	220 nF/km	Cable Length (d)	75 km

Table 5.2: MTdc network parameters used in the case study.

5.7 Simulation Results

Droop Control

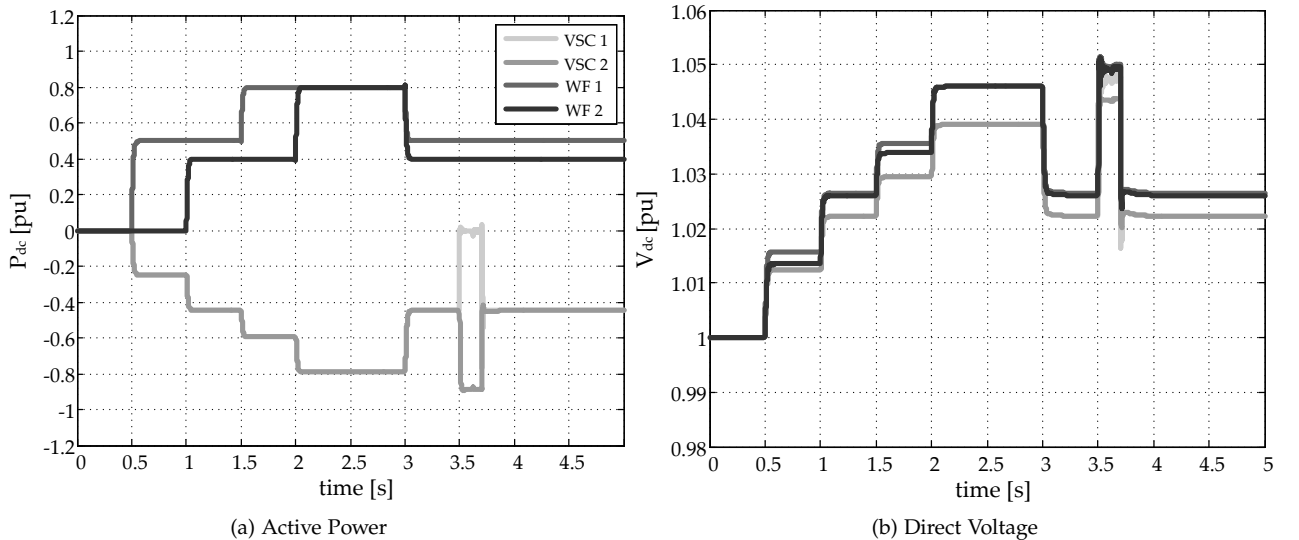
The droop voltage control method was implemented such that both VSC1 and VSC2 terminals have the same droop characteristic, shown in Figure 5.1. As a result, the power produced by the wind farms is equally shared among the two converter stations (see Figure 5.11 (a)).

Since the droop control is equivalent to a proportional regulator, the dynamic behaviour of the active power is actually given by the inner current controller loop, which has fast dynamics. As a consequence, the changes in the direct voltage with the different operating points occur almost instantaneously.

This phenomenon can be easily seen on the direct voltage transient response during the ac fault on the ac grid 1, between $3.5 \leq t \leq 3.7$ s. The direct voltage quickly rises to a value around the maximum allowable value – 1.05 pu as set by the droop controller – and returns as rapidly to its previous value once the fault is cleared.

Extending the droop control method to MTdc networks with more terminals should be straightforward. The downside of the droop control method as presented, regards the fact that steering the power produced by the wind farms to a particular node in the network is not possible. The power flow each converter station receives will depend on its droop characteristics and its dc cable resistance.

Figure 5.11: Simulation results for the droop control strategy.



Ratio Control

In the ratio control method, the VSC1 and VSC2 terminals have different droop characteristics [158], represented in Figure 5.2. The power ratio, n , between the VSC1 and VSC2 terminals during the numerical simulation, is given in Table 5.3.

Table 5.3: Power ratio between VSC1 and VSC2 used in the ratio control strategy case study.

Ratio [pu]	Time [s]
50/50	$0 < t < 1$
70/30	$1 < t < 2$
40/60	$2 < t < 3$
50/50	$t > 3$

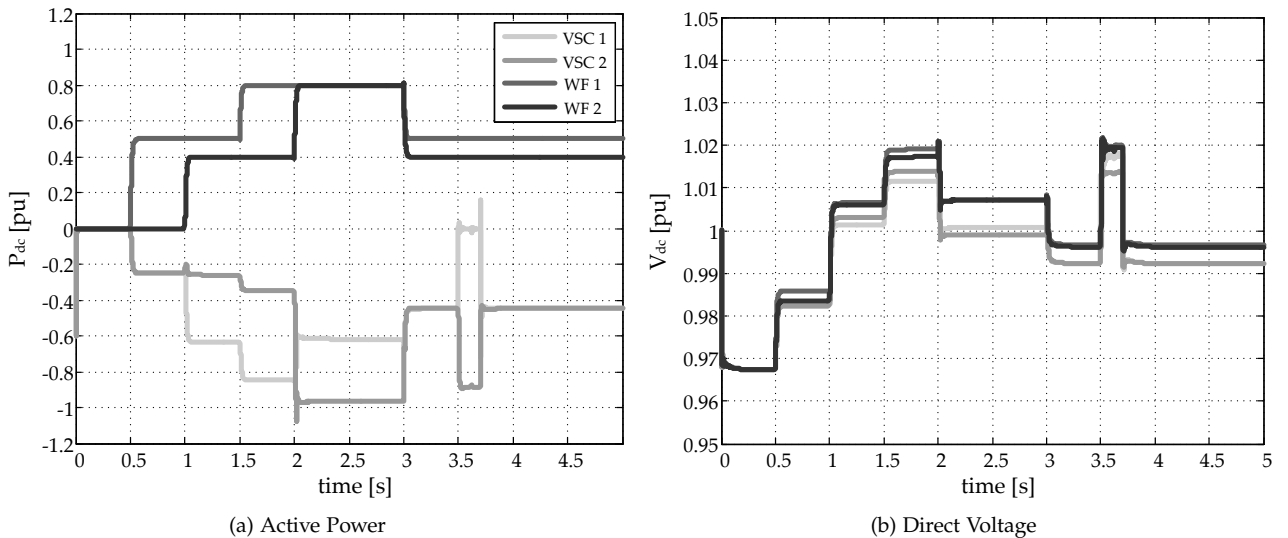
The simulation results show that the power division is not exactly equal the value established by the power ratio coefficient, although the precision is above 95%. The loss in precision is due to the hypothesis shown in (5.4), which assumes that the ratio between the converters dc-side currents is equal to their dc-side active power ratio.

As for the droop control, the ratio control can be traced back to a proportional gain. However, in the ratio control, this proportional gain – equal to the inverse of the droop slope – is not constant. If the gain is made too high, i.e. the slope too low, the direct voltage can display an oscillatory or even have an unstable behaviour.

Since it employs a proportional controller, the ratio control scheme shows a fast response during the fault on the ac side of VSC1. However, during the fault the direct voltage rose to 1.02 pu instead of 1.05 pu when droop control was used. This happens because the power ratio, n , is set to 50/50 during the fault, so that the maximum allowable direct voltage of both converters is 1.02 pu as shown in Figure 5.2.

As previously mentioned, a downside of the ratio control approach is its expandability. It may be difficult to find an analytic expression which would correctly share the power in a MTdc network where more than two stations are controlling the direct voltage. In addition, the analytic expression depends on the resistance of the dc cables, which may vary, further affecting the method accuracy [158].

Figure 5.12: Simulation results for the ratio control strategy.



Priority Control

As explained in Section 5.4, in the priority control method the one converter terminal – in this case study VSC1 – will try to control the MTdc network voltage at a pre-defined level until it reaches its full capacity.

This behaviour can be clearly seen in Figure 5.13 during the first two direct voltage transients: when the two wind farms start producing power, respectively at $t = 0.5$ s and $t = 1$ s, the first converter brings the MTdc voltage back to 1.0 pu.

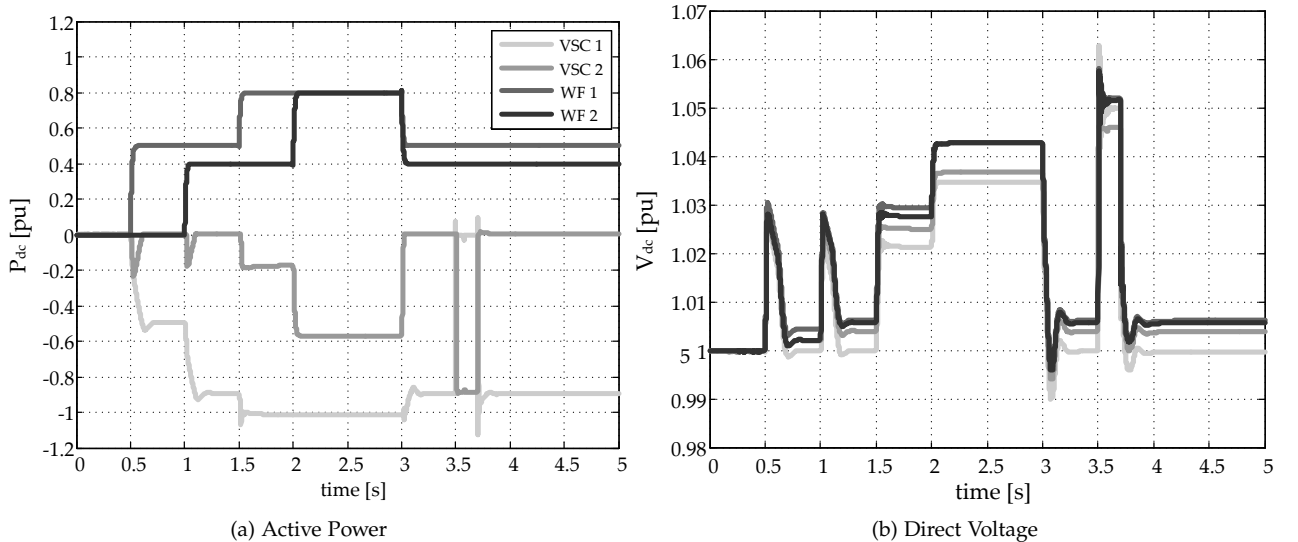
During the transients, the direct voltage initially rises to approximately 1.03 pu and is then re-established to its pre-defined level of 1 pu in approximately 200 ms. When the VSC1 terminal saturates at $t = 1.5$ s, the VSC2 terminal starts receiving the exceeding power from the wind farms and the direct voltage varies according to the droop characteristic of the VSC2 terminal. Subsequently, at $t = 3$ s, when the wind farms power is reduced, the VSC1 terminal comes out of saturation bringing back the direct voltage to its initial value of 1 pu and, thus, no more power is sent to the other onshore terminal.

Finally, when the fault happens in the ac grid of VSC1 at $t = 3.5$ s, the VSC2 almost instantaneously start to receive all the power being generated offshore. As a consequence, the system direct voltage rises to around 1.05 pu during the fault since the VSC2 employs a proportional controller (see Figure 5.3). After the fault is cleared, at $t = 3.7$ s, the VSC1 regains control over the direct voltage bringing it back to its reference value of 1 pu.

The priority control strategy is interesting for small MTdc networks where a specific country wishes to have precedence over the power produced by its wind farms, and is willing to sell the exceeding power to neighbouring countries. However, it is not clear how this control method can be extended to MTdc networks with a larger number of nodes¹⁵.

¹⁵ A solution could be to combined the priority control strategy with the ratio control strategy, but also in the latter expansion to MTdc networks with higher number of nodes seems to be challenging.

Figure 5.13: Simulation results for the priority control strategy.



Voltage Margin Method

The last control strategy to be considered in the case study is the voltage margin method. Undoubtedly, from all the analysed methods, the voltage margin is the one with the highest flexibility and expandability. In fact, the method can be used to emulate the other control strategies presented, such as the ratio and priority controllers as discussed in Section 5.5.

A voltage margin scheme where the VSC1 terminal has the priority over the VSC2 terminal – shown in Figure 5.9 – has been implemented in this case study¹⁶.

In comparison with the original priority controller, the dynamic response of the voltage margin method was not as fast. This effect can be clearly seen in the direct voltage transient response shown in Figure 5.14 (b). In all the previous results, the direct voltages have shown transients which were less than 5% the nominal voltage, including during the period when there is a fault on ac grid 1.

For the VMM the direct voltage transients were somewhat higher, with the highest overvoltage being 12% above nominal value during normal operation and a little over 20% during the ac grid 1 fault¹⁷.

Another downside of the VMM is that, in practice, only one VSC station is controlling the MTdc network voltage at a given time. Additionally, with a limited direct voltage operating range – e.g. $\pm 5\%$ or $\pm 10\%$ the nominal voltage – the maximum number of VSC terminals that can be controlled by the VMM may be limited to avoid adverse interaction between the controls of each terminal due to possible too low voltage margins¹⁸.

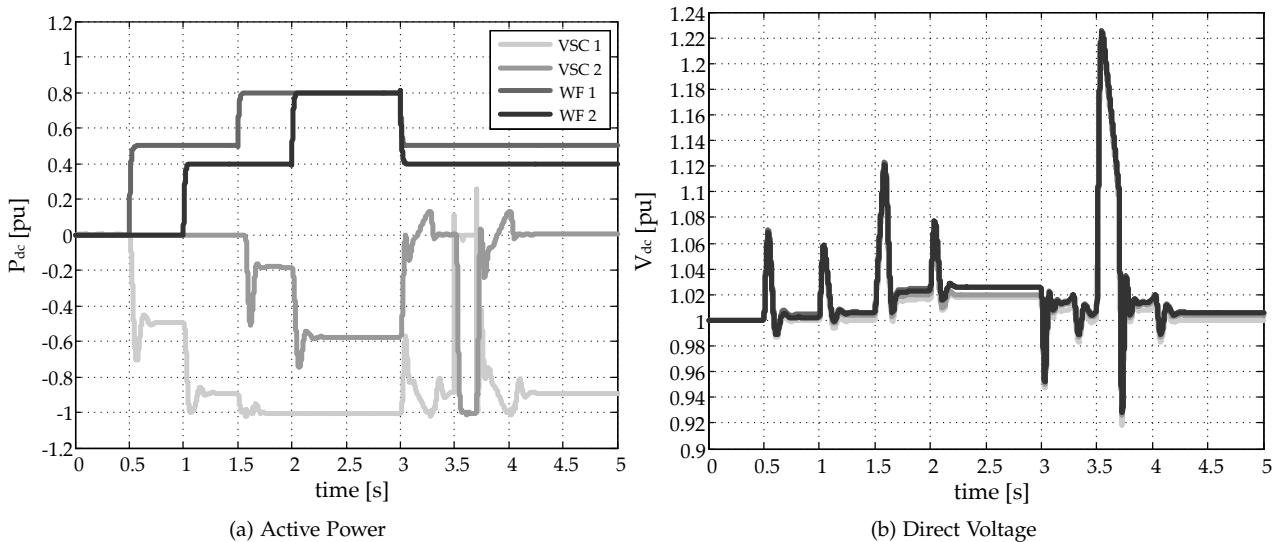
Additional results from the simulations are given in Appendix B, where the current and voltages of the two voltage controlling converter stations (VSC1 and VSC2) are displayed from Figure B.1 until Figure B.4.

¹⁶ With the aid of communication and knowledge of the power produced by the wind farms, it would also be possible to use the VMM to implement the ratio control strategy by varying the VSC2 terminal active power reference, P_{ac}^* , accordingly (see Figure 5.6).

¹⁷ The dynamic response of the VSC active power – shown in Figure 5.14 (a) – immensely affects the amplitude of the direct voltage during transients. The way the method is constructed, by cascading several PI controllers, could be responsible for the more sluggish response.

¹⁸ Nevertheless, given its flexibility, extending the VMM to MTdc networks with a higher number of nodes should be easier to accomplish than for the previous controllers.

Figure 5.14: Simulation results for the voltage margin method control strategy.



5.8 Conclusion

To guarantee a secure and reliable grid operation, future large multi-terminal dc networks will require that the responsibility of controlling the direct voltage inside the system is shared by more VSC-HVdc stations.

A desirable control strategy for large MTdc networks will have fast dynamic behaviour; high flexibility, i.e. ability to control the network power flow; high expandability and; if possible, low communication requirements.

For the comparison performed in this Chapter, no single control method has performed well according to the establish criteria. Table 5.4 reviews the characteristics of the analysed control strategies.

The droop control method has a low flexibility, as it is not able to control the power flow inside MTdc networks. Although the ratio and priority control methods have a higher flexibility than the droop control method, they have low expandability, i.e. they would be difficult to implement in larger MTdc networks.

Lastly, although the voltage margin method is the most flexible of the analysed methods, it has also the worst dynamic performance due to the way the method is constructed by cascading PI controllers. A possible work around could be to combine the VMM with the droop control strategy, making the first more flexible and the latter more responsive.

Chapter 6 introduces a novel control strategy, called *Distributed Voltage Control*, which works by sharing the direct voltage control amongst more VSC-HVdc stations present in a MTdc network. The main goal is to overcome the shortcomings of the analysed control strategies, namely their flexibility and expandability characteristics.

Table 5.4: Comparison of the different evaluated control strategies.

Control Method	Droop	Ratio	Priority	Voltage Margin
Dynamic Response	High	High	Medium	Low
Expandability	Medium	Low	Medium	High
Flexibility	Low	Medium	Medium	High
Communication Requirement	Low	Medium	Low	Medium

6

The Distributed Voltage Control Strategy

Union is strength.

Maxim, Aesop, 620-560 B.C.

Chapter 5 presented the most common methods for controlling the direct voltage in MTdc networks. However, all the analysed methods suffered from different issues, such as limited power flow control, difficult expandability to larger MTdc networks and poor dynamic performance. The overall aim of the present chapter is to present a novel control strategy, named *Distributed Voltage Control* (DVC), which focuses on controlling the VSC-HVdc terminals direct voltages to control the power flow inside MTdc networks. The chapter starts with an overview of the control strategy methodology. The operation of the DVC control strategy is then tested in three different case studies, and an attempt to calculate the telecommunication needs of the control method is given. Finally, the DVC strategy performance is compared to the methods analysed in Chapter 5, and its superiority in terms of overall performance is shown.

- 6.1. Control Methodology
- 6.2. Minimisation of System Losses in a 5-terminal MTdc Network (Case Study 1)
- 6.3. Solving the OPF Problem with a Genetic Algorithm (Case Study 2)
- 6.4. DVC Strategy Telecommunication needs
- 6.5. Control and Operation of a Large MTdc Network (Case Study 3)
- 6.6. Conclusion

This chapter is based on the following publications:

R. Teixeira Pinto, P. Bauer, S. Rodrigues, E. Wiggelinkhuizen, J. Pierik, and B. Ferreira, "A Novel Distributed Direct-Voltage Control Strategy for Grid Integration of Offshore Wind Energy Systems Through MTDC Network," *IEEE Transactions on Industrial Electronics*, vol. 60, no. 6, pp. 2429 - 2441, June 2013.

R. Teixeira Pinto, S. F. Rodrigues, E. Wiggelinkhuizen, R. Scherrer, P. Bauer, and J. Pierik, "Operation and Power Flow Control of Multi-Terminal DC Networks for Grid Integration of Offshore Wind Farms Using Genetic Algorithms," *Energies*, vol. 6, no. 1, pp. 1-26, 2012.

S. Rodrigues, R. Teixeira Pinto, P. Bauer, and J. Pierik, "Optimal Power Flow Control of VSC-based Multi-Terminal DC Network for Offshore Wind Integration in the North Sea," *IEEE Journal of Emerging and Selected Topics in Power Electronics* - Early Access, vol. PP, no. 99, pp. 1-9, 2013. [Online]. Available: <http://ieeexplore.ieee.org/arnumber=6600728>

Table 6.1: Comparison between HVac and HVdc networks.

Characteristic	HVAc	HVdc
Synchronisation Parameter	ω	V_{dc}
Voltage Change	$V_1 \sin \delta$	ΔV_{dc}
Connection Impedance	X	R_{dc}
Active Power	$V_1 V_2 \frac{\sin \delta}{X}$	$V_{dc} \frac{\Delta V_{dc}}{R_{dc}}$
System Inertia	J	C
System Energy	$J \frac{\omega^2}{2}$	$C_{dc} \frac{V_{dc}^2}{2}$

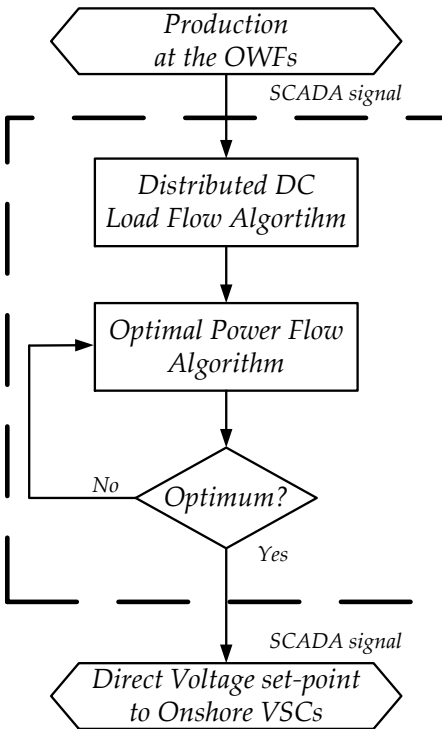


Figure 6.1: Flowchart diagram for the DVC control strategy.

¹ As the DVC strategy relies only on a power flow solution, there is no need for a fast communication link between the network terminals. The information for the dc power flow can be gathered by a TSO through use of a SCADA (Supervisory Control and Data Acquisition) communication system just as it is regularly done for the control of power plants in ac networks. The advantage of the DVC strategy is that, in practice, a certain load flow scenario can be kept for a fixed amount of time (e.g. 15 min. control cycle), hence, a fast communication link is not needed. Nevertheless, it is necessary to be able to send the voltage references to the VSC-HVdc stations onshore and offshore once every control cycle. A detailed analysis of the time needed for a complete control cycle is performed in Section 6.4.

6.1 Control Methodology

A more suitable control strategy for large multi-terminal dc networks, would be to assign each dc-voltage-controlling VSC terminal with a specific direct voltage set-point [163]. In this way, any predefined load flow scenario can be achieved while no single converter is left alone with the responsibility of balancing the power inside the transmission system, i.e. the control of the dc system voltage is distributed between several nodes inside the MTdc network. This novel method of controlling VSC-MTdc networks, here presented, is called *Distributed Voltage Control*.

Distributed control is a common practice in ac networks, where no single power station is left alone with the task of guaranteeing system balance. Table 6.1 displays a brief comparison between different quantities for HVac and HVdc networks [164].

The main difference concerning the control of both systems is the synchronisation parameter: it is the frequency for ac networks whereas voltage for dc ones. Whilst ac controllers will try and make sure that the frequency is fixed through the entire ac system, the same cannot happen for dc controllers.

With the exception of superconductive networks, if the direct voltage is the same throughout the network, there will be no power flow. To assign each dc-voltage-controlling VSC with a specific voltage set-point it is first necessary to solve a load flow.

Figure 6.1 shows the DVC control strategy flowchart diagram showing the steps in the calculation of the direct-voltage reference values to be sent to the onshore VSC-HVdc terminals [163]. The main steps in the DVC strategy are discussed next. The focus is particularly on the distributed dc load flow algorithm and the power flow optimisation, which are of great importance for the development of control strategies which are capable of operating in large MTdc networks¹.

DC Load Flow

As shown in Chapter 3, the classical load flow iteration process can be written as:

$$\begin{cases} \mathbf{V}_{dc}(k+1) = \mathbf{V}_{dc}(k) + \Delta \mathbf{V}_{dc}(k) \\ \Delta \mathbf{V}_{dc}(k) = -\mathbf{J}(k)^{-1} \cdot \mathbf{g}_P(\mathbf{V}_{dc}(k)) \end{cases} \quad (6.1)$$

In comparison with the classical ac load flow, since in dc networks the phase angle is not defined, the state variables are simplified as:

$$\mathbf{V}_{dc} = [V_{dc1}, \dots, V_{dcN-1}]^T \quad (6.2)$$

where the slack node is considered to be the last node (N-th node) of the dc network.

The vector that holds the mismatch equation is also simplified as, in dc networks, there is no need to write equations for the reactive power. In addition, during steady state, only the resistive part of the

transmission cables play a role, thus, the load flow equations become:

$$\begin{cases} \mathbf{g_P}(\mathbf{V_{dc}}(k)) = [g_{P_1}, \dots, g_{P_{N-1}}]^T \\ g_{P_i} = P_{Gi} - P_{Li} - \sum_{j \neq i} V_{dci} V_{dcj} Y_{ij} - Y_{ii} V_{dci}^2 \end{cases} \quad (6.3)$$

where;

$\mathbf{g_P}$ is the load flow equation vector [W] and;

g_{P_i} is the load flow equation of node i in the MTdc network [W]².

The simplified Jacobian matrix, J , which is defined as the variation of the mismatch equations with respect to the state variables, becomes:

$$\begin{cases} J(\mathbf{V}(k)) = \frac{\partial \mathbf{g_P}}{\partial \mathbf{V}} = \begin{pmatrix} \frac{\partial g_{P_1}}{\partial V_1} & \dots & \frac{\partial g_{P_1}}{\partial V_{N-1}} \\ \vdots & \ddots & \vdots \\ \frac{\partial g_{P_{N-1}}}{\partial V_1} & \dots & \frac{\partial g_{P_{N-1}}}{\partial V_{N-1}} \end{pmatrix} \\ \frac{\partial g_{P_i}}{\partial V_k} = \begin{cases} -Y_{ik} V_i & \text{for } k \neq i \\ -\sum_{j \neq i} V_j Y_{ij} - 2Y_{ii} V_i & \text{for } k = i \end{cases} \end{cases} \quad (6.4)$$

Optimal Power Flow for DC Networks

The optimal power flow (OPF) problem is a common tool used for the optimisation of a given ac power system network. The idea behind it, is to find the optimal values of the network parameters which will optimise the system functionalities, such as e.g. system losses, total generation cost, operational limits or system security [165–167].

Before solving the OPF problem for a MTdc network, it is first necessary to define the state variables, \mathbf{x} , and the specified variables \mathbf{z} . In addition, the specified variables can be separated as control variables, \mathbf{U} , and fixed variables, \mathbf{W} , such as:

$$\mathbf{z} = \begin{bmatrix} \mathbf{U} & \mathbf{W} \end{bmatrix}^T \quad (6.5)$$

Generally, in ac systems, the state variables, \mathbf{x} , are defined as the load angle and the voltage on each PQ bus – where the node voltage is unknown – or only as the load angle on PV buses, where the node voltage is known. In a dc system, as shown in (6.1), the state variables can only be the nodal voltage of P-type buses, where voltages are unknown. Table 6.2 shows a comparison between the different types of network buses in ac and dc networks.

Therefore, according to Table 6.2, the control variables, \mathbf{U} , are the voltage references of the V-type buses, whereas the net power of the P-type buses are the fixed variables, \mathbf{W} . After defining the state and specified variables, the OPF, without inequality constraints, can then be defined as a minimisation problem:

$$\begin{cases} \min f(\mathbf{x}, \mathbf{U}) \\ \text{s.t. } \mathbf{g_P}(\mathbf{x}, \mathbf{U}, \mathbf{W}) = 0, \end{cases} \quad (6.6)$$

² The Y_{ij} and Y_{ii} coefficients come from the dc network admittance matrix and are calculated based on the conductance of the dc cables as shown in Section 3.4.

Table 6.2: Comparison between HVac and HVdc network bus types.

Bus Characteristic	HVac	HVdc
Voltage is unknown	PQ bus	P bus
Voltage is known	PV bus	V bus

P-type buses: Generation and demand are known but voltage is unknown (VSC-HVdc stations controlling their power output).

V-type buses: Voltage is known but generation is unknown (VSC-HVdc stations controlling the dc system voltage, i.e. slack-buses).

where;

$f(\mathbf{x}, \mathbf{U})$ is the function to be optimised and;

$\mathbf{g_P}(\mathbf{x}, \mathbf{U}, \mathbf{W})$ are the load flow equations as given in (6.3).

Optimisation Method: Steepest Gradient

To solve the OPF problem, the gradient method, also known as the method of steepest decent, is used. Constructing the unconstrained Lagrangian function, yields:

$$L(\mathbf{x}, \mathbf{U}, \mathbf{W}) = f(\mathbf{x}, \mathbf{U}) + \boldsymbol{\lambda}^T \mathbf{g_P}(\mathbf{x}, \mathbf{U}, \mathbf{W}) \quad (6.7)$$

where;

L is the Lagrangian function and;

$\boldsymbol{\lambda}$ is the vector of the lagrangian multipliers³.

³ The size of $\boldsymbol{\lambda}$ is given by the number of load flow equations.

The minimisation conditions of the unconstrained Lagrangian function are then given by:

$$\begin{cases} \nabla L_{\mathbf{x}} = \frac{\partial L}{\partial \mathbf{x}} = \frac{\partial f}{\partial \mathbf{x}} + \left[\frac{\partial \mathbf{g_P}}{\partial \mathbf{x}} \right]^T \cdot \boldsymbol{\lambda} = 0 \\ \nabla L_{\mathbf{U}} = \frac{\partial L}{\partial \mathbf{U}} = \frac{\partial f}{\partial \mathbf{U}} + \left[\frac{\partial \mathbf{g_P}}{\partial \mathbf{U}} \right]^T \cdot \boldsymbol{\lambda} = 0 \\ \nabla L_{\boldsymbol{\lambda}} = \frac{\partial L}{\partial \boldsymbol{\lambda}} = \mathbf{g_P}(\mathbf{x}, \mathbf{U}, \mathbf{W}) = 0 \end{cases} \quad (6.8)$$

The solution steps of the OPF problem with the steepest gradient algorithm are as follows [165,166]:

1. Assign an initial value to control vector \mathbf{U}^0 ;
2. Solve the load flow eq.: $\nabla L_{\boldsymbol{\lambda}} = \mathbf{g_P}(\mathbf{x}, \mathbf{U}, \mathbf{W}) = 0$;
3. With \mathbf{x} and $\mathbf{J} = \partial \mathbf{g_P} / \partial \mathbf{x}$, from step 2, solve $\nabla L_{\mathbf{x}}$ w.r.t. $\boldsymbol{\lambda}$:

$$\boldsymbol{\lambda} = -[\mathbf{J}^T]^{-1} \frac{\partial f}{\partial \mathbf{x}} \quad (6.9)$$

4. With the new value of $\boldsymbol{\lambda}$, compute $\nabla L_{\mathbf{U}}$;
5. If $|\nabla L_{\mathbf{U}}| \geq \varepsilon$ go to the next step. Otherwise, the optimisation is achieved;
6. Compute the new control vector \mathbf{U}^{k+1} :

$$\mathbf{U}^{k+1} = \mathbf{U}^k - \beta |\nabla L_{\mathbf{U}}| \quad (6.10)$$

Restart, from step 2, with \mathbf{U}^{k+1} .

Inclusion of Constrains

To obtain a feasible power-flow solution, it is necessary to integrate inequality constrains of the system variables into the optimisation process. Examples of inequality constrains for MTdc systems could be, amongst others, the nodal voltages in the network, the power flow in the network lines and the VSC-HVdc power ratings.

Inequality constraints on control variables, \mathbf{U} , such as the reference value of the VSC stations set to control the MTdc voltage, can be handled by the optimisation algorithm without the need to alter the objective function.

If a particular variable of the new set of control variables, \mathbf{U}^{k+1} , infringes a limit, then that variable is set to the constrained limit, i.e.:

$$\begin{cases} \text{if : } U_i^{k+1} > U_i^{\max} \Rightarrow U_i^{k+1} = U_i^{\max} \\ \text{if : } U_i^{k+1} < U_i^{\min} \Rightarrow U_i^{k+1} = U_i^{\min} \end{cases} \quad (6.11)$$

where;

U_i^{k+1} is the i-th control variable at iteration $k + 1$ and;

U_i^{\max} and U_i^{\min} are the i-th control variable limits.

In case a control variable violates the constraints, the Kuhn-Tucker theorem gives the necessary conditions for a minimum, if the objective function involved is convex [165,166].

The inclusion of inequality constraints on state and dependent variables is done by use of penalty functions. The penalty functions, M_i , are usually described as the quadratic difference between the violated variable and its limit as:

$$M_i = m_i (x_i - x_i^{\lim})^2 \quad (6.12)$$

where;

m_i is the penalty factor and;

x_i is the i-th state variable.

Using penalty functions, inequality constraints are introduced, only when active, as equality constraints⁴. In this way, the OPF can be still solved by the gradient method using an augmented optimisation function:

$$L(\mathbf{x}, \mathbf{U}, \mathbf{W}) = f(\mathbf{x}, \mathbf{U}) + \sum_i M_i(\mathbf{x}, \mathbf{U}) + \lambda^T \mathbf{g}_P(\mathbf{x}, \mathbf{U}, \mathbf{W}) \quad (6.13)$$

6.2 Minimisation of System Losses in a 5-terminal MTdc Network (Case Study 1)

It is possible to apply the steepest descent gradient method to solve the OPF problem using the losses in a MTdc network as the objective function. The total transmission losses in a MTdc grid, P_{losses} , can be expressed as⁵:

$$f(\mathbf{x}, \mathbf{U}) = P_{\text{losses}}(\mathbf{x}, \mathbf{U}) = (\mathbf{I}_M \mathbf{V}_{\text{dc}})^T \mathbf{Y}_P (\mathbf{I}_M \mathbf{V}_{\text{dc}}) \quad (6.14)$$

It is important to describe the losses in the MTdc system as a function of the nodal voltages rather than the nodal currents. This is due to the fact that the state variables are given by the voltages of P-type buses, as shown in (6.2). The next step is the inclusion of the inequality constraints. Taking into account only the MTdc

⁴ If a variable is not violating a constraint then its penalty factor is zero.

⁵ \mathbf{Y}_P is the dc network primitive admittance matrix and \mathbf{I}_M is its incidence matrix as defined in Section 3.4

nodal voltages as inequality constraints, the penalty functions may be written as:

$$M_{Vi} = m_{Vi} \left(V_{dci} - V_{dci}^{lim} \right)^2 \quad (6.15)$$

where;

M_{Vi} is the i-th node direct voltage penalty function;

m_{Vi} is the i-th node direct voltage penalty factor;

V_{dci} is the i-th node direct voltage and;

V_{dci}^{lim} is the limit of the i-th node direct voltage;

In this case, when building the augmented function, it is not necessary to include a function for the control variables. As previously mentioned, the control variables can have their value restricted directly, during the OPF solution. Finally, by combining (6.13) with (6.14), the lagrangian function becomes:

$$L(\mathbf{x}, \mathbf{U}, \mathbf{W}) = P_{losses}(\mathbf{x}, \mathbf{U}) + \sum_i M_{Vi}(\mathbf{x}) + \lambda^T \mathbf{g}_P(\mathbf{x}, \mathbf{U}, \mathbf{W}) \quad (6.16)$$

Numerical Example

The MTdc network to be considered in this case study is depicted in Figure 6.2, and the system rated parameters are given in Table 6.3.

For the network displayed in Figure 6.2, the offshore wind farms, as well as the hub nodes (middle nodes), are generation nodes and are therefore considered as P-type buses. The onshore VSC stations are all controlling the MTdc network voltage and are then considered V-type buses, i.e. slack buses. The system variables are therefore assigned as:

1. state variables: $\mathbf{x} = \mathbf{V} = \begin{bmatrix} V_{dc1} & V_{dc2} & V_{dc3} & V_{dc4} & V_{dc5} \end{bmatrix}^T$;
2. control variables: $\mathbf{U} = \begin{bmatrix} V_{dc6} & V_{dc7} \end{bmatrix}^T$;
3. fixed variables: $\mathbf{W} = \begin{bmatrix} P_{dc1} & P_{dc2} & P_{dc3} & P_{dc4} & P_{dc5} \end{bmatrix}^T$.

The total system losses for the considered MTdc network can be calculated as:

$$P_{losses}(\mathbf{x}, \mathbf{U}) = Y_{11} (V_{dc1} - V_{dc4})^2 + Y_{22} (V_{dc2} - V_{dc4})^2 + \dots + Y_{66} (V_{dc5} - V_{dc7})^2 \quad (6.17)$$

⁶ During normal operation, the voltage range of the MTdc network was allowed to be $\pm 10\%$ the nominal value.

On the other hand, the inequality constraints may be written as⁶:

$$\sum_{i=1}^5 M_{Vi}(\mathbf{x}) = m_{V1} \left(V_{dc1} - V_{dc1}^{lim} \right)^2 + \dots + m_{V5} \left(V_{dc5} - V_{dc5}^{lim} \right)^2 \quad (6.18)$$

Lastly, the lagrangian multipliers are, $\lambda^T = \begin{bmatrix} \lambda_1 & \dots & \lambda_5 \end{bmatrix}$, and

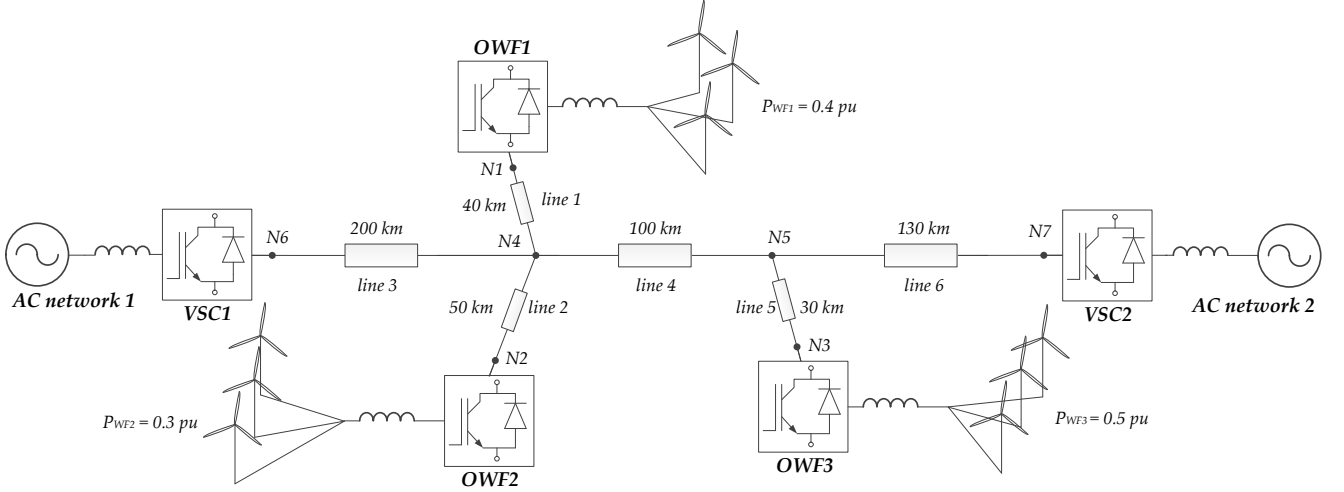


Figure 6.2: Radial 5-terminal VSC-MTdc network analysed in case study 1.

the five load flow equations are given by:

$$g_{P_i}(\mathbf{x}, \mathbf{U}, \mathbf{W}) = P_{dci} - \sum_{j=1}^5 V_{dci} V_{dcj} Y_{ij}, \text{ for } \forall i = 1, \dots, 5. \quad (6.19)$$

Results

To compare between non-optimal and optimal results, the obtained data is presented for three different scenarios. Table 6.4 summarises the presented scenarios, and Table 6.5 gives the results of the optimal power flow problem solved with the steepest gradient method.

The values are presented in a per unit basis, with the base voltage being equal to the VSC dc-side voltage, i.e. ± 200 kV, whereas the base power is equal to the installed capacity of the offshore wind farms, i.e. 500 MW, as shown in Table 6.3.

Scenario i

In the first scenario, the optimisation was not conducted. Instead, a dc load flow was performed considering VSC1 as a fixed load with $P_6 = -0.9$ pu, while VSC2 was left with the responsibility of controlling the MTdc network voltage. In the second scenario, the losses in the MTdc network are optimised but only VSC2 is a slack node, meaning that VSC1 is still left as a fixed load and it is not helping with voltage regulation. Finally, in the last scenario, the optimisation was performed considering both onshore converters as slack nodes.

As one would expected, without any optimisation the transmission losses in the MTdc network are at its highest with 12.3 MW or 2.46%. This is mainly because the voltage set-point of VSC2 is not optimised and it is assigned to 1.0 pu.

Table 6.3: Parameters of the MTdc Network analysed in case study 1.

Parameter	Value
AC Grid Power (S_k)	3500 MVA
AC Grid Voltage (E_L)	220 kV
OWF Power (P_{ac}^{owf})	500 MW
OWF Voltage (V_{owf})	33 kV
VSC Power (S_c)	600 MVA
VSC Voltage (V_c)	180 kV
Trafo Impedance (z_t)	$0.005 + j0.10$ pu
Phase Reactor (z_c)	$0.003 + j0.15$ pu
MTdc Voltage (V_{dc})	400 kV
	(± 200) kV
VSC Capacitor (C_{dc})	75 μ F
Cable Resistance (r_{dc})	0.200 Ω /km
Cable Inductance (l_{dc})	19.10 mH/km
Cable Capacitance (c_c)	220 nF/km

Table 6.4: Different analysed scenarios in case study 1.

Scenario	Description	Slack Node
i	No optimisation	VSC2
ii	Losses optimisation	VSC2
iii	Losses optimisation	VSC1 & VSC2

Node	Scenario i		Scenario ii		Scenario iii	
	V_{dc} [pu]	P_{dc} [pu]	V_{dc} [pu]	P_{dc} [pu]	V_{dc} [pu]	P_{dc} [pu]
OWF1	1.0036	0.4000	1.1003	0.4000	1.1001	0.4000
OWF2	1.0035	0.3000	1.1002	0.3000	1.1000	0.3000
OWF3	1.0062	0.5000	1.1026	0.5000	1.0981	0.5000
N4	1.0017	0.0000	1.0985	0.0000	1.0984	0.0000
N5	1.0044	0.0000	1.1009	0.0000	1.0965	0.0000
VSC1	0.9793	-0.9000	1.0782	-0.9000	1.0867	-0.5205
VSC2	1.0000	-0.2754	1.0969	-0.2754	1.0867	-0.6658
Losses	2.46%		2.03%		1.37%	

Table 6.5: load flow results of the loss optimisation.

Scenario ii

In the second scenario, with the optimisation already in place – and VSC2 solely responsible for the voltage control – the transmission losses are reduced to 2.03%, almost half percent lower in comparison with the non-optimal scenario.

After the optimisation, a voltage set-point of 1.0969 pu was assigned to VSC2 bringing the voltage of the offshore wind farms very close to the maximum permissible voltage⁷.

Scenario iii

The transmission losses optimisation was lastly performed with both onshore converters working together to control the voltage inside the MTdc the network. As a result of the optimisation, the power assigned to VSC1 was reduced from 0.90 pu to 0.52 pu. This is a direct result from the fact that the VSC1 is now also a slack node.

Indeed, to further minimise the transmission losses, the optimisation algorithm assigned the same voltage set-point of 1.0867 pu to both VSC1 and VSC2. As a result, the system losses were reduced by 1.09% in comparison with the non-optimised results (see Table 6.5).

However, to optimise the transmission losses, the direct voltage on the offshore wind farms is brought close to their operational limit of 1.10 pu. During normal operation, having the wind farms voltage close to the maximum allowable voltage is not of concern. Nonetheless, a possible outage in some node of the MTdc network could give rise to an overall increase in the voltage profile, causing problems to the network nodes that are operating close to the voltage limit. A possible solution to this issue is to integrate an N-1 contingency analysis into the optimisation algorithm.

N-1 Security Analysis

Only a minor change to the steepest gradient method is required to guarantee that the MTdc network remains N-1 safe for contingencies in one of the onshore ac networks.

⁷ In fact, the reason why the direct voltages on the converters of the offshore wind farms are slightly above 1.10 pu is because the penalty functions do not impose a rigid limit on the objective function, rather, they show the weakest points of the optimisation problem [49]. To implement rigid limits one possible solution is to use heuristic methods such as a genetic algorithm [50].

After solving the load flow – step 2 of the algorithm flowchart shown in Figure 6.1 – it is now necessary to verify whether the obtained solution is N-1 secure or not. The network is N-1 secure if, after an outage on an arbitrary node, the parameters of the remaining operational nodes do not surpass the stipulated constraints. If the network is N-1 secure, the algorithm can proceed, otherwise, the optimisation is halted and the last feasible solution is taken as the optimisation result. The extended DVC strategy flowchart, including the N-1 security algorithm, is shown in Figure 6.3 [163].

Two additional scenarios, described in Table 6.6, are studied to verify the DVC strategy behaviour with the N-1 security algorithm: when only one onshore VSC is controlling the MTdc network voltage (scenario iv), and when both VSC are operating as slack nodes (scenario v). Table 6.7 contains the results of the loss optimisation in the MTdc network taking into consideration the N-1 contingency analysis.

Scenario iv

As it can be seen from Table 6.7, when all the network nodes are operational, the new voltage reference set-point assigned to VSC2 is 1.0731 pu. Before, when the N-1 contingency analysis was not included in the optimisation algorithm, the voltage reference was 1.0969 pu, as shown in Table 6.5.

As a result, the optimised losses rose from 2.03% to 2.13%. Nevertheless, including the N-1 analysis still provided lower losses than the first scenario (2.46%), and made the network N-1 contingency proof. The maximum permissible voltage of 1.10 pu happens on the offshore wind farm 1 (OWF1) when the VSC1 terminal is faulted.

The last row of Table 6.7 cannot be filled in the scenario iv, because VSC2 is the only slack node in the network. In reality, if only VSC2 would be working as a slack node, a fault in that terminal would disrupt the power balance in the MTdc network, giving rise to overvoltages which would then trigger protective equipment to safeguard the HVdc terminals.

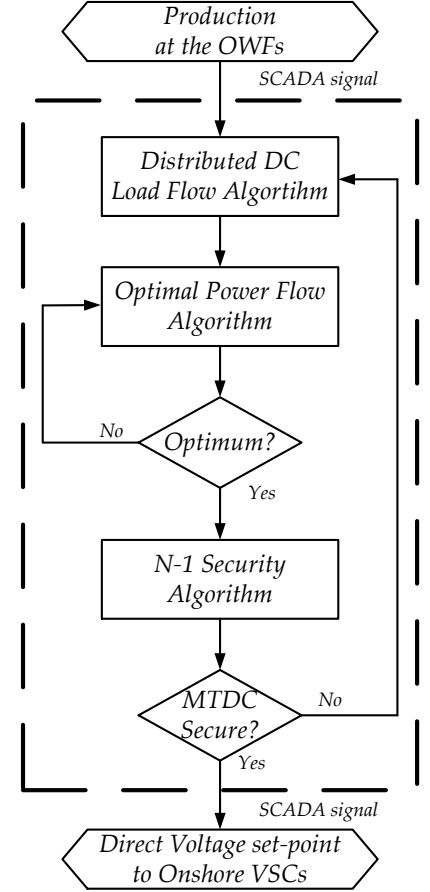


Figure 6.3: Control topology flowchart diagram for the DVC control strategy including the N-1 security analysis.

Table 6.6: Additional scenarios of case study 1.

Scenario	Description	Slack Node
iv	Losses opt. + N-1 security	VSC1
v	Losses opt. + N-1 security	VSC1 & VSC2

Table 6.7: load flow results of the loss optimisation with N-1 security analysis.

Faulted VSC	Scenario iv							Scenario v					
		WF1	WF2	WF3	VSC1	VSC2	Losses	WF1	WF2	WF3	VSC1	VSC2	Losses
None	V _{DC}	1.0765	1.0764	1.0789	1.0539	1.0731	2.13%	1.0798	1.0797	1.0777	1.0661	1.0661	1.42%
	P _{DC}	0.4000	0.3000	0.5000	-0.9000	-0.2787		0.4000	0.3000	0.5000	-0.5205	-0.6658	
WF1	V _{DC}	1.0642	1.0659	1.0730	1.0432	1.0731	2.37%	1.0732	1.0749	1.0750	1.0661	1.0661	0.66%
	P _{DC}	0.0000	0.3000	0.5000	-0.9000	0.1237		0.0000	0.3000	0.5000	-0.3098	-0.4836	
WF2	V _{DC}	1.0687	1.0669	1.0745	1.0459	1.0731	2.24%	1.0762	1.0744	1.0757	1.0661	1.0661	0.82%
	P _{DC}	0.4000	0.0000	0.5000	-0.9000	0.0224		0.4000	0.0000	0.5000	-0.3625	-0.5293	
WF3	V _{DC}	1.0692	1.0691	1.0699	1.0464	1.0731	2.04%	1.0764	1.0763	1.0709	1.0661	1.0661	0.67%
	P _{DC}	0.4000	0.3000	0.0000	-0.9000	0.2204		0.4000	0.3000	0.0000	-0.3716	-0.3217	
VSC1	V _{DC}	1.1000	1.0999	1.0921	1.0982	1.0731	2.58%	1.0932	1.0931	1.0853	1.0914	1.0661	2.61%
	P _{DC}	0.4000	0.3000	0.5000	0.0000	-1.1742		0.4000	0.3000	0.5000	0.0000	-1.1739	
VSC2	V _{DC}	-	-	-	-	-	-	1.0946	1.0945	1.1000	1.0661	1.0983	3.36%
	P _{DC}	-	-	-	-	-	-	0.4000	0.3000	0.5000	-1.1664	0.0000	

Scenario v

As previously discussed, a better way to control MTdc networks is to distribute the responsibility of the voltage control amongst more terminals. In scenario v both onshore converters are sharing the voltage control inside the MTdc network. However, differently from the results of scenario iii, shown in Table 6.5, this time also the N-1 security analysis is taken into account.

As before, with two slack nodes, the optimisation algorithm assigned the same voltage set-point to both VSC1 and VSC2 although, due to the inclusion of the N-1 contingency analysis, the set-point was reduced from 1.0867 pu to 1.0661 pu. The reduction in the voltage reference slightly increased the transmission losses (see Table 6.7)⁸

Nevertheless, the transmission losses in scenario v are still more than 1% lower than the base scenario without any optimisation. In the end, having an increase in the transmission losses of 0.05% is a minor drawback when compared with the advantage of having a MTdc network that is optimised and N-1 secure. In fact, with the distributed voltage control strategy, if both onshore converters are controlling the MTdc network voltage, the system can successfully maintain operation even if one node of the network is lost while still operating with optimised transmission losses⁹.

Hitherto, only steady-state phenomena have been analysed. Dynamic simulations are needed to confirm the obtained load flow results and to evaluate the dynamic behaviour of the complete system operating under the proposed distributed voltage control strategy.

Dynamic Simulations

Once more, the simulated network is the one depicted in Figure 6.2, and the MTdc network dynamic parameters are the ones given in Table 6.3. The dynamic models utilised for the VSC-HVdc system, the MTdc network, and the ac grids are the ones presented in Chapter 4. The simulation results are given in Figure 6.4, Figure 6.5 and Figure 6.6.

The OPF algorithm only takes into consideration the MTdc network transmission losses. The losses shown in Figure 6.6 are the transmission losses only, not the total losses in the MTdc network, which would include the converter losses. However, the DVC strategy sets the voltage in the MTdc network as high as possible to guarantee the desired power flow; to ensure the network remains N-1 secure and to minimise the transmission losses.

Therefore, it can be expected that the losses in the VSC-HVdc converters should also be optimised since the converters would always operate with the highest possible direct voltage for a given desired power flow scenario.

The offshore VSC terminals are set to control the ac system voltage and frequency of the wind farms to fixed values; whereas the onshore VSC terminals are set to control the exchanged reactive power

⁸ For the optimisation with two slack nodes, the losses were 1.37% without the N-1 contingency analysis, whereas it was 1.42% with the N-1 security algorithm. A small price to pay to have a more secure system.

⁹ However, assuming that the network displayed in Figure 6.2 is used to connect two countries, it is most likely that the power flow between them will be set by a system operator and, thus, it will not always be possible to assign it to optimise the network losses. Nevertheless, the distributed voltage control strategy can still be used to establish the desired load flow while keeping the MTdc network N-1 secure. The method has shown to work regardless of the network size and can be extended to cases with more country connections while actually benefiting from the increase in the number of slack nodes, as it will be shown in Section 6.3 and Section 6.5.

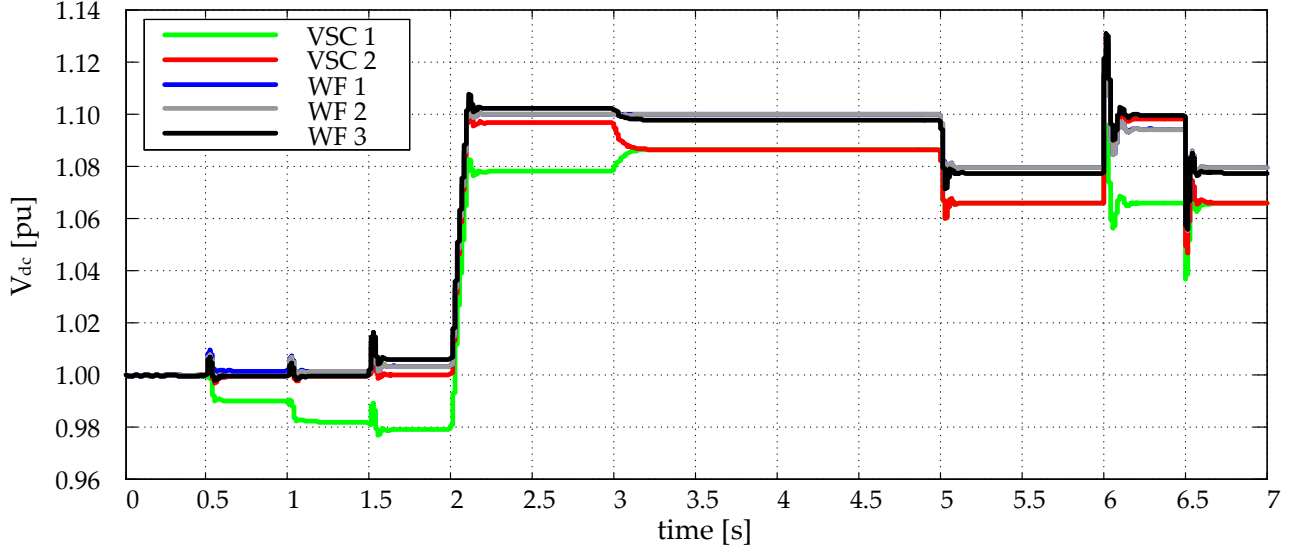


Figure 6.4: MTdc system voltages at the on-shore and offshore wind farms VSCs

with the ac grids and the voltage of the MTdc network.

At the beginning of the simulation, no power is being transmitted and all the nodes inside the network have 1.0 pu direct voltage. The converter at the offshore wind farms are unblocked at $t = 0.5$ s, and the offshore wind farms start transmitting power. The offshore wind farms are generating, 0.4, 0.3 and 0.5 pu, respectively. The wind farms power vary step-wise at different times, $t = 0.5$, $t = 1.0$ and $t = 1.5$ s, respectively for OWF1, OWF2 and OWF3. This shows that the DVC method is capable of controlling the dc system voltage in a stable way, even when there is a step in the wind power being transmitted through the VSC1 or VSC2. Initially, the VSC2 is controlling its direct voltage at 1.0 pu and the VSC1 is receiving the power being generated offshore up to 0.9 pu. At simulation time $t = 1.5$ s, the system losses are 2.46% as displayed in Table 6.5 and shown in Figure 6.6.

At $t = 2$ s, the optimisation algorithm sends a new reference voltage set-point to VSC2 and its voltage is risen from 1.0 pu to 1.069 pu. The system response is very fast and the voltage transient lasts for less than 200 ms. During the transient, the power in VSC2 drops to about 0.80 pu, but is restored to its initial value of 0.90 pu after the transient is finished. As a consequence of a higher dc system voltage profile, the system losses are now reduced to 2.03%. At this point the MTdc network is being operated with only VSC2 as a slack node. If a fault would occur at that terminal, power balance inside the network would be lost and the offshore wind farms would have to quickly apply some fast power reduction method. In addition, dc choppers in the onshore HVdc terminals would also have to be activated once the voltage would have risen to dangerous values [57].

Therefore, at $t = 3$ s, the onshore VSC1 is also called in by the optimisation algorithm to help with voltage regulation inside the MTdc network and to reduce the overall transmission losses. At that moment, the voltage references of both VSC1 and VSC2 are made equal

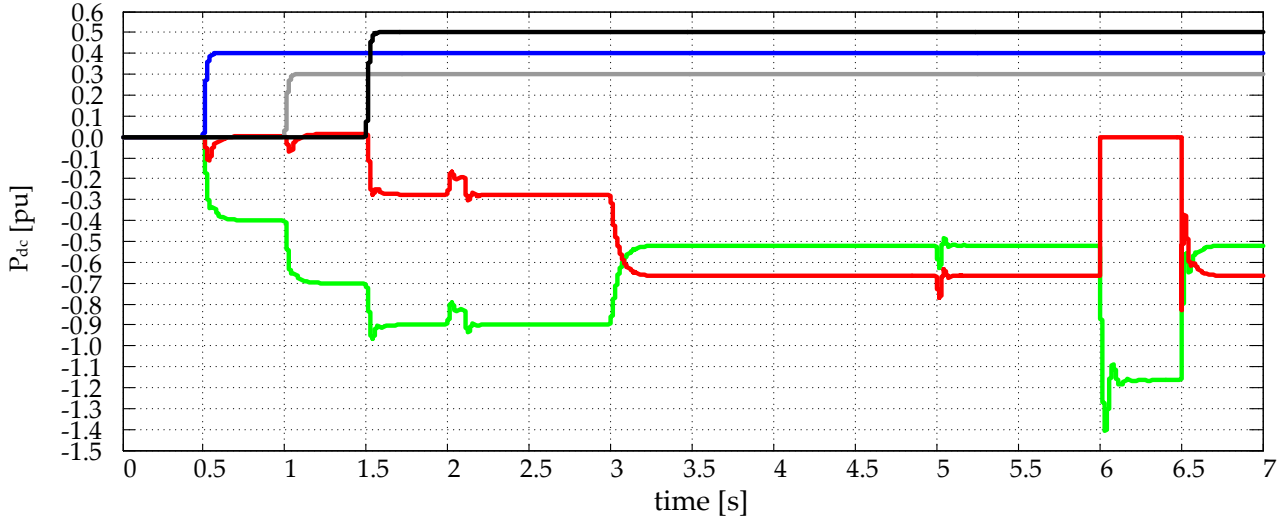


Figure 6.5: Active power at the onshore and offshore wind farms VSCs.

to 1.0867 pu. As a consequence, the losses in the transmission system are further reduced to 1.37%.

However, as it can be seen from Figure 6.4, from $2 \leq t \leq 4$ s, the voltages at the offshore wind farm nodes are being operated very close to the maximal permissible limit of 1.10 pu. This is due to the fact that no consideration regarding the N-1 contingency analysis had been implemented, up to that point, in the optimisation algorithm.

Then, at $t = 5$ s, new voltage reference set-points, which take into account N-1 security constraints, are sent to VSC1 and VSC2. Accordingly, the voltage on both nodes is reduced from 1.0867 pu to 1.0661 pu, while on the wind farm terminals the voltage is reduced from around 1.10 pu to circa 1.08 pu.

Due to the reduction in the network voltage profile, the losses in the transmission system are increased. Nevertheless, the losses are still optimised and the increase from 1.37% to 1.42% is, as shown in Figure 6.6, practically insignificant. The advantage of this new operating point is that the MTdc network is now N-1 secure. To demonstrate the inclusion of the N-1 security analysis in the distributed voltage control strategy, a 3-phase fault is applied to the ac grid connected to VSC2 at simulation time, $t = 6$ s. The fault duration is 500 ms to show that the DVC method can withstand long, and even permanent, faults.

It is worth noting that during the fault, the current control on the VSC2 terminal is set to provide full reactive current support – 1 pu, i.e. up to the rated converter capability – as required by the most stringent grid codes [58]¹⁰. This is shown in Figure 6.5, where the active power going through VSC2 is instantaneously zeroed to provide full reactive current support during the ac network voltage dip.

As previously mentioned, if this was the only direct voltage controlling node, power balance in the MTdc network would have been

¹⁰ The effects of stringent grid codes on the stability behaviour of MTdc systems is further analysed in the first sections of Chapter 7.

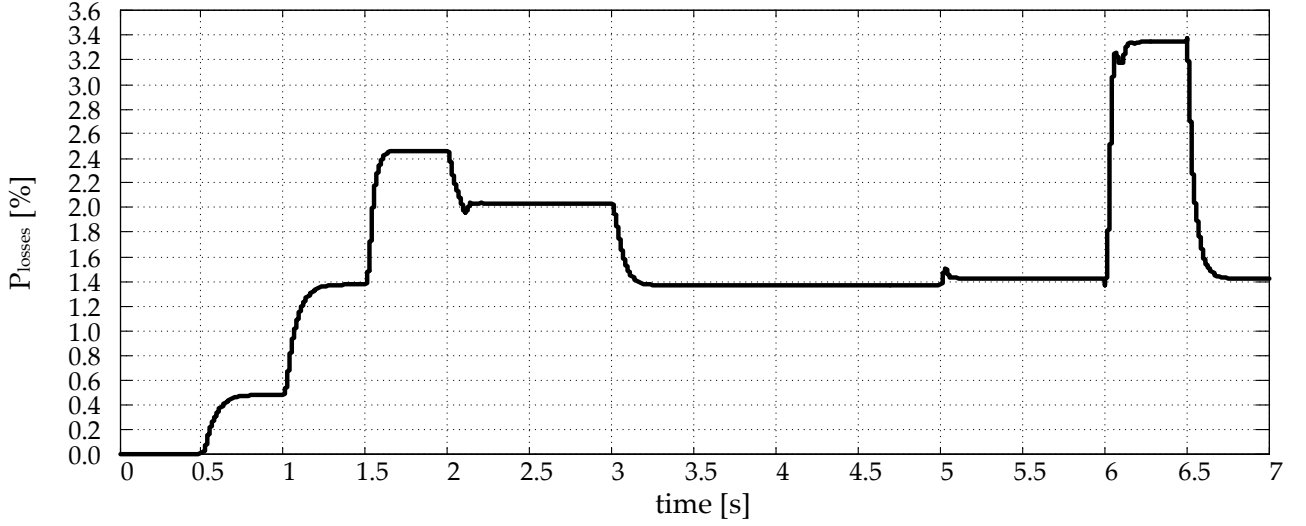


Figure 6.6: Total system transmission losses.

lost and the dc system voltage would start to rise, an event which could potentially power down the whole MTdc transmission system. Instead, with the distributed voltage control strategy, once the VSC2 terminal is faulted, to maintain power balance, the VSC1 terminal increases its power inversion from 0.52 pu to 1.17 pu after a short transient, which lasts less than 200 ms. During the fault, the direct voltage on the third offshore wind farm (OWF3) has an overshoot peak of circa 1.13 pu. However, being only 3% over the nominal range, these brief overvoltages are not of concern [57]. In fact, once the transients are over, the direct voltage at the WF3 is successfully brought back by VSC1 to 1.10 pu – i.e. inside the normal operating range – showing that, with the distributed voltage control strategy, the MTdc network is indeed N-1 secure. After the fault is cleared, the MTdc network successfully returns to the previous operating point after a brief transient.

6.3 Solving the OPF Problem with a Genetic Algorithm (Case Study 2)

The distributed voltage control strategy assigns each dc-voltage-controlling VSC terminal with a specific voltage set-point [163]. In this way, the MTdc network voltage control is distributed amongst several nodes, i.e. no single converter assumes alone the responsibility of balancing the power inside the transmission system. This control approach increases reliability, by adding redundancy, and provides the possibility to control the power flow inside the dc network to any feasible load flow scenario.

The DVC method relies on the solution of an optimal power flow problem, which can be solved via any optimisation method. In the previous Section, the OPF problem was solved using the steepest descent gradient method. However, this method has several disadvantages, namely:

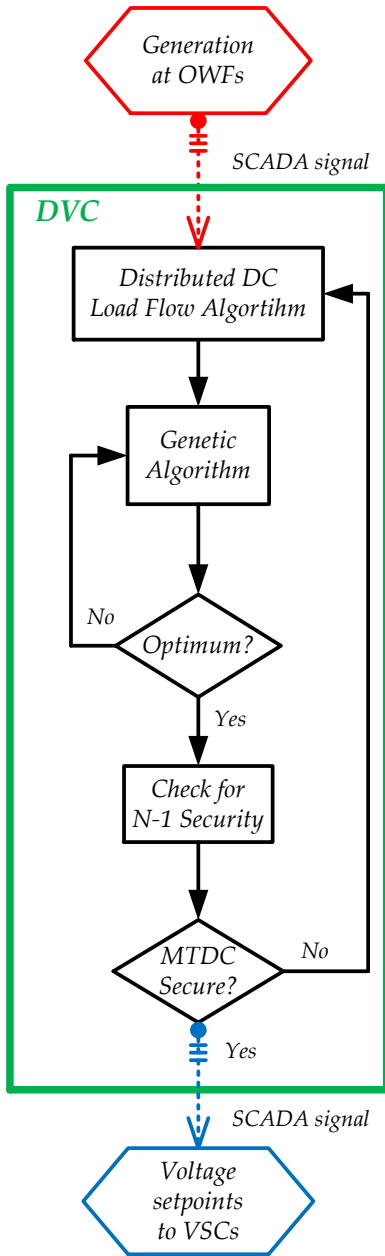


Figure 6.7: Control topology flowchart diagram for the DVC control strategy with a genetic optimisation algorithm.

The method works as follows: at first, the DVC receives the power production at the OWFs. Then, a distributed dc load flow algorithm is run to obtain a first solution for the genetic algorithm [168]. The constraints and specific parameters for the genetic algorithm are set by the transmission system operator (TSO) [169]. Next, the solutions generated by the genetic algorithm are checked for N-1 security. The distributed DC load flow algorithm then runs N load flow scenarios, with one dc node defective at a time, to check whether the MTdc network is N-1 secure for the obtained power-flow scenario. If there is a feasible solution which is N-1 secure, the DVC sends the direct voltage setpoints to VSC-HVdc terminals controlling the MTdc network voltage.

- derivatives must be calculated;
- information about the optimisation goals needs to be available;
- not possible to use discrete variables;
- it is difficult to include problem constraints and variables boundaries;
- multi-objective optimisation is hard to implement.

Due to the aforementioned reasons, using the steepest descent optimisation in MTdc networks with a large number of nodes would prove difficult. Additionally, it is hard to implement the method when multiple and conflicting objective goals need to be considered. Therefore, a genetic algorithm (GA) has been developed to solve the OPF problem [168,169]. The algorithm is explained next.

Genetic Algorithm

Genetic algorithms are one of the branches of evolutionary algorithms, first introduced by Holland in 1975 [170]. These algorithms are efficient and robust search and optimisation tools that allow parallel search since a population of solutions is used. Each individual contained in the population is also designated as a chromosome. Moreover, such algorithms are highly flexible since, differently from most search methods, they do not require any information other than the evaluations of functions [171]. The function to be optimised is usually designated as fitness function. The main reasons for using a GA are:

- there is no need for calculating derivatives;
- no information about the optimisation goals is required besides evaluating the fitness function;
- it is possible to use continuous and discrete variables;
- it is easier to include problem constraints and variables boundaries;
- multi-objective optimisation is possible and easy to implement.

The flowchart of the DVC strategy using a genetic algorithm is displayed in Figure 6.7, whereas Figure 6.8 displays the flowchart of the genetic algorithm. Each step of the GA flowchart is presented and explained next.

Step 1 – Population initialisation

At the initialisation, a random population is created. The composition of each individual chromosome is given in (6.20). Encoded in the chromosomes are the direct voltage references of all onshore

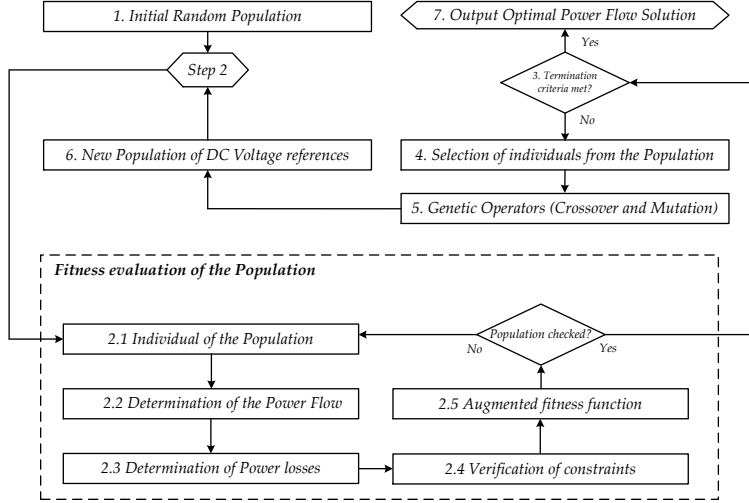


Figure 6.8: Flowchart of the Genetic Algorithm implemented to solve the MTdc network optimal power flow problem.

nodes, the values for the augmented fitness function and the maximum constraint violation.

$$\mathbf{x} = \begin{bmatrix} V_{dc1}^* & \cdots & V_{dcN}^* & AugFit & MaxConst \end{bmatrix} \quad (6.20)$$

where;

V_{dci}^* is the dc system voltage reference of the i -th onshore VSC;

$AugFit$ corresponds to the chromosome augmented fitness value and;

$MaxConst$ stands for the value of the highest constraint violation.

As a results, the genetic algorithm output is the direct voltage references of the VSC working as slack nodes, which is a subset of \mathbf{x} .

Step 2 – Fitness evaluation

In Step 2, the objective function – i.e. the fitness value – is evaluated for each chromosome. In Step 2.2, the load flow inside the MTdc network is calculated by solving (6.3). In step 2.3, the objective function, taken as the MTdc network losses, P_{losses} , is calculated for each chromosome according to (6.14).

Step 2.4 – Constraints

Although the non-linear load flow equations always returns a solution, extra constraints are implemented in the genetic algorithm to assure the obtained load flows are feasible. The constraints handling was performed through a penalty technique [172]. An augmented fitness, which is the sum of the fitness value (Step 2.3) and the penalty term (Step 2.4), is attributed to each chromosome in Step 2.5. Figure 6.9 displays the constraints implemented in the GA.

Step 3 – Termination Criterion

The algorithm will end whenever the termination criterion is met. The end is triggered whenever the best solution in the population presents a maximum constraint violation lower than a given value, e.g. $\varepsilon = 10^{-5}$. When the genetic algorithm finishes solving the OPF

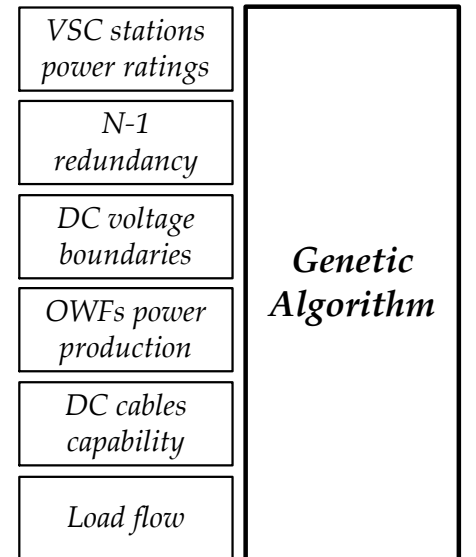


Figure 6.9: Constraints incorporated in the genetic algorithm.

The applied constraints guarantee there are no overloaded dc cables, the direct voltages of all MTdc nodes respect the limits and the load flow solutions are N-1 secure – i.e. the produced wind power can still be exported – complying with network and TSO constraints, even if an outage occurs in any VSC terminal.

problem, it outputs the direct voltage references for the VSC terminals controlling the MTdc network voltage.

Step 4 – Selection

After determining the population augmented fitness, the GA continues by selecting solutions from the population (Step 4). It uses an elitist approach to make sure the best solutions in the population will be carried onto the next generation. A 4-th tournament selection is used to populate the mating pool [173].

Step 5 – Genetic Operators

After selection, to create new solutions the mutation and crossover genetic operators are applied to the mating pool individuals. A point mutation and a heuristic crossover are used [174]. After a new population is created (Step 6), it is evaluated again with regard to the fitness function (Step 2).

Numerical Example

To test the DVC strategy in conjunction with the genetic algorithm, a multi-terminal dc grid representing a simplified topology of the North Sea Transnational grid is studied [175]. The MTdc network topology is shown in Figure 6.10¹¹.

Each country has its own offshore wind farm (the red dots in Figure 6.10) named UK1, NL1 and DE1. The yellow lines represent a pair of HVdc transmission cables and the intermediate nodes – N4, N5, N6 – are cable joints. The wind farms size and location are derived by clustering the main offshore wind farms in the North Sea southern part; it includes wind farms in construction and planning phase.

The wind farms, as well as the ac networks, are connected to the MTdc grid through a single voltage-source converter station. The nominal power of each wind farm is 1 GW¹². Trading offshore wind or onshore generated power is possible via line3 and line6, as shown

¹¹ This topology represents only a fraction of the possible future grid and is located in the southern part of the North Sea. It comprises of a MTdc network containing nine nodes connecting the three European countries which are most likely to invest in offshore wind energy: the United Kingdom; The Netherlands and Germany.

¹² The ratings of all six VSC stations are chosen equal to 1 GW to make it possible to transport all wind power to the country that owns the wind farm.

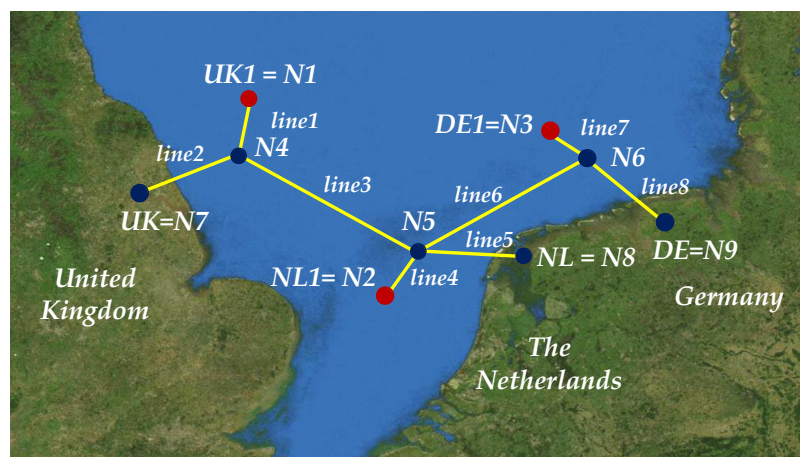


Figure 6.10: Radial VSC-MTdc network with 6 terminals [175].

in Figure 6.10, up to the VSC stations capacity. Table 6.8 gives the dc transmission length of each cable whereas other MTdc system parameters are given in Table 6.9.

Dynamic Simulations

To examine the behaviour and capability of the distributed voltage control strategy in reliably and safely operating the dc network, four different case studies have been selected. Their aim is to show how the DVC strategy performs when facing some of the most common situations when controlling a MTdc grid for integration of OWFs, i.e.: the start-up procedures; normal operation; operation under wind curtailment; and operation under a contingency in one ac network node. The dynamic simulations were performed according to the scenarios described in Table 6.10. All scenarios are simulated for a total time of 150 seconds (see Table 6.10).

Start-up Procedures: Scenario i

During the MTdc network start-up procedure, the system direct voltage is brought to 1 pu (± 320 kV), by the grid-side voltage-source converters. Figure 6.11 shows the simulation results for scenario i. The upper graph shows the active power being injected (positive power) or absorbed (negative power) in the MTdc network in each VSC terminal, whereas the lower graph shows the MTdc voltage at each node.

The first node to unblock and start operation is the UK one, at simulation time $t = 0.1$ s. The direct voltage controller very rapidly injects about 0.5 pu (500 MW) of power into the MTdc network, bringing the system voltage from zero to 1 pu in about 300 ms.

Then, 300 ms after the UK onshore VSC was unblocked, all other

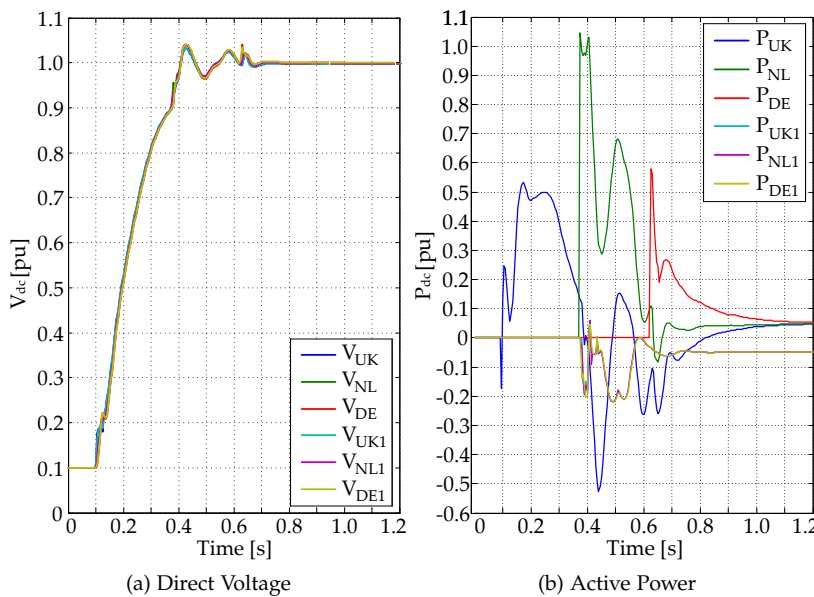


Table 6.8: Length of HVdc lines used in case study 2.

Line	Start	End	Length [km]
line1	N1	N4	60
line2	N4	N7	120
line3	N4	N5	190
line4	N2	N5	60
line5	N5	N8	120
line6	N5	N6	220
line7	N3	N6	50
line8	N6	N9	110

Table 6.9: Parameters of the MTdc network analysed in case study 2.

Parameter	Value
System Base Power (S_b)	1000 MVA
AC Grid Short Circuit Power (S_k)	3000 MVA
AC Grid HV Side Voltage (E_L)	380 kV
OWF Collection Voltage (V_{owf})	33 kV
VSC Voltage (V_c)	275 kV
Trafo Impedance (z_t)	$0.005 + j0.100$ pu
VSC LCL-Filter Size - AC Grid (S_f)	200 MVA
VSC Filter Size - OWF (S_f)	50 MVA
Phase reactor Impedance (z_c)	$0.003 + j0.150$ pu
VSC DC-side Capacitor (C_{dc})	75 μ F
MTdc Network Voltage (V_{dc})	± 320 kV
DC Cable Resistance (r_{dc})	0.0195 Ω /km
DC Cable Inductance (l_{dc})	19 mH/km
DC Cable Capacitance (c_c)	220 nF/km
DC Cable Cross Section (A_{dc})	2200 mm ²
DC Cable Rated Current (I_{dc})	2.086 kA

Figure 6.11: Results from scenario i: a. MTdc Start-up.

	Scenario	Description
i. Start-up Procedures	a. MTdc Start-up	During start-up, the dc system voltage is charged from zero to the rated value by the grid-side VSC stations.
	a. Priority	Priority is given to the country where the wind energy is being produced, i.e., all the power goes to the rightful country; while there is no energy trade.
ii. Normal Operation	b. Proportional Sharing	The sum of all the energy being produced by the OWFs is equally divided amongst all the countries through energy trade via the MTdc network.
	c. Power flow Reversal	The power flow of the German node is reversed. At first the power is flowing from the MTdc network into Germany.
iii. Wind Curtailment	a. Low-wind Scenario	The MTdc system behaviour is analysed during wind curtailment in a scenario where the wind energy generation is low.
	b. High-wind Scenario	The MTdc system behaviour is analysed during wind curtailment in a scenario where the wind energy generation is high.
iv. AC Contingency	a. Low-wind Scenario	The system behaviour is analysed during an ac fault at the UK node in a scenario with low wind energy generation. In this case study the MTdc network is N-1 secure.
	b. High-wind Scenario	The system behaviour is analysed during an ac fault at the UK node with high wind generation. In this case study the MTdc network may not be $N - 1$ secure.

Table 6.10: Description of the analysed scenarios in case study 2.

nodes, with exception of the German onshore VSC, are unblocked. The OWFs absorb some power for their own start-up, which makes the transient for the Dutch onshore node somewhat larger than the one for the UK onshore VSC.

Finally, the German onshore VSC is unblocked at $t = 0.6$ s, and the MTdc network undergoes a fast transient, which only creates minor oscillations in the dc system voltage¹³.

The results of scenario i demonstrate that the complete start-up procedure of the MTdc network can be done very quickly, in less than a second. In reality, such a kick-start might not be needed under normal operation. However, since VSC stations do not have the means to block dc faults, and the development of high-power high-current dc short-circuit breakers is yet incipient, being able to promptly black-start the MTdc network might be useful in helping to clear dc faults.

Normal Operation: Scenario ii

In this scenario, the British, Dutch and German OWFs are producing wind energy with an average value of about 0.5 pu, 0.8 pu and 0.4 pu, respectively. Figure 6.12, Figure 6.13 and Figure 6.14 show the simulation results for scenario ii-a, ii-b and ii-c, respectively¹⁴.

Instead of sending all the OWF power to the owner state, it is possible to share the produced energy (scenario ii-a) via the MTdc grid as shown in Figure 6.12.

In scenario ii-b, the UK, Netherlands and Germany share equally all the power being generated at the OWFs. In this case, the to-

¹³ The system voltage does not start from zero but from 0.1 pu (see Figure 6.11). This is to avoid division by zero in the model, since, according to (4.52), the current flowing into the dc network is calculated as the active power divided by the dc system voltage.

¹⁴ In all the simulation results, the OWF and onshore VSC active power is displayed, as well as the MTdc network voltage.

tal production is 1.8 pu and each country receives a little less than 0.6 pu, which is due to the MTdc grid transmission losses of 0.85 pu on average (see Figure 6.13).

In scenario ii-c, the power flow in the MTdc network is arbitrarily set by the TSO. During the first 20 seconds, the power in the MTdc network is exactly as in scenario ii-a, where priority is given to the producing country.

From simulation time $20 \leq t \leq 80$ s, the UK onshore node starts receiving 1 pu from the MTdc network, whereas the Dutch node receives 0.9 pu. Since the power in the MTdc network has to be balanced at all times, the power flow in the German node is reversed. During that period, the German onshore node will be injecting – i.e. selling – about 0.20 pu of power to the MTdc grid.

It is worth noting that the onshore nodes are effectively controlling their dc-side voltage and not directly the load flow, as the DVC method dictates. Nevertheless, Germany is the node that is providing the extra power to balance the MTdc network losses. This is achieved in the OPF optimisation by setting Germany as the network slack node. The purpose is to speed up the OPF solution with the genetic algorithm. Towards the end of the simulation, the power from the German node is again reversed as the power to the British and Dutch node is set by the TSO as being equal to 0.5 pu.

Wind Curtailment: Scenario iii

The third scenario analyses the distributed voltage controller behaviour when the OWF power has to be curtailed. In the low-wind scenario, the British, Dutch and German OWFs are producing wind energy with an average value of about 0.5 pu, 0.8 pu and 0.4 pu, respectively, thus the total production of the OWFs is 1.8 pu.

The results for scenario iii-a are shown in Figure 6.15. Before the curtailment starts at $t = 40$ s, the TSO is setting the DVC strategy to priority control as in scenario ii-a; hence, until that point in time, the results of both cases are identical. Afterwards, from $40 \leq t \leq 60$ s, the Dutch and German OWFs are ordered to curtail their power outputs to 0.4 and 0.3 pu, respectively. The OWFs total power production after curtailment is 1.2 pu, so the power at the GS-VSC also

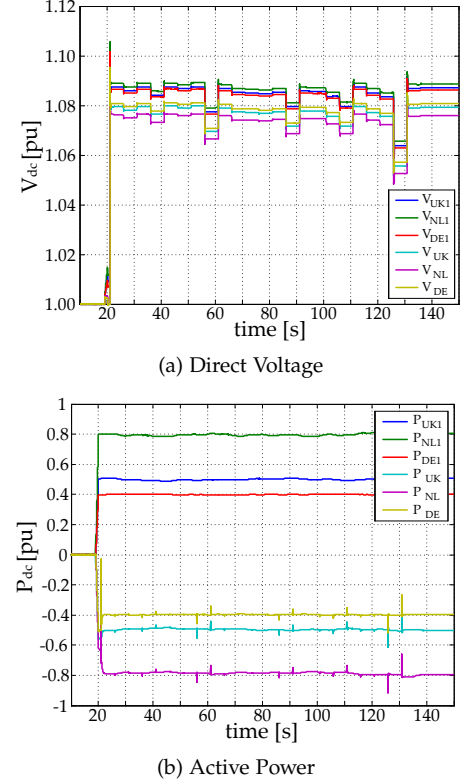
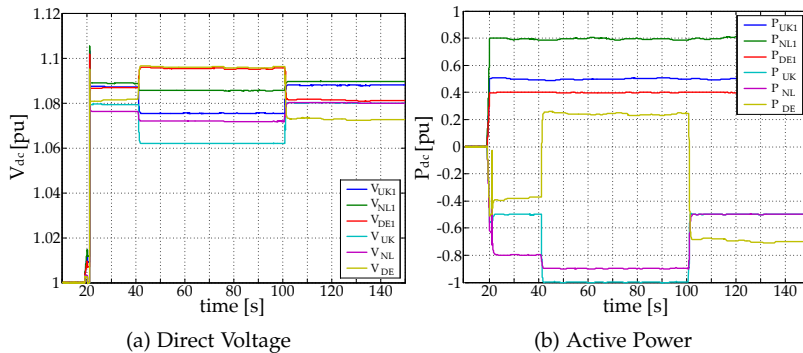


Figure 6.12: Results from scenario ii a.: Priority.

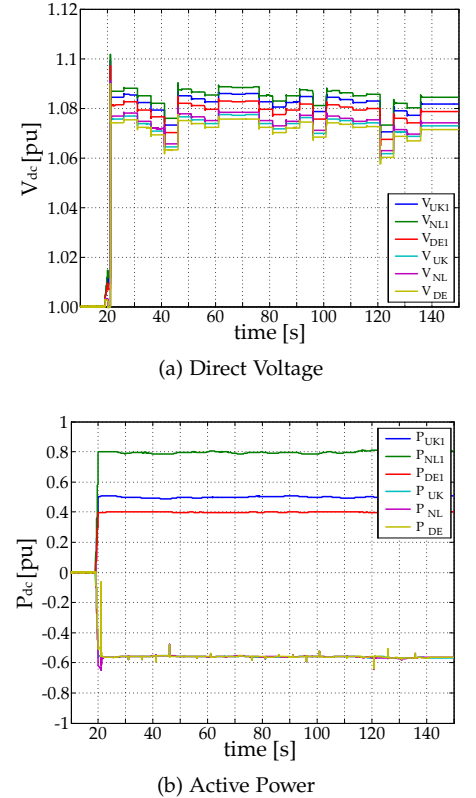


Figure 6.13: Results from scenario ii b.: Proportional Sharing.

Figure 6.14: Results from scenario ii c.: Power Flow Reversal.

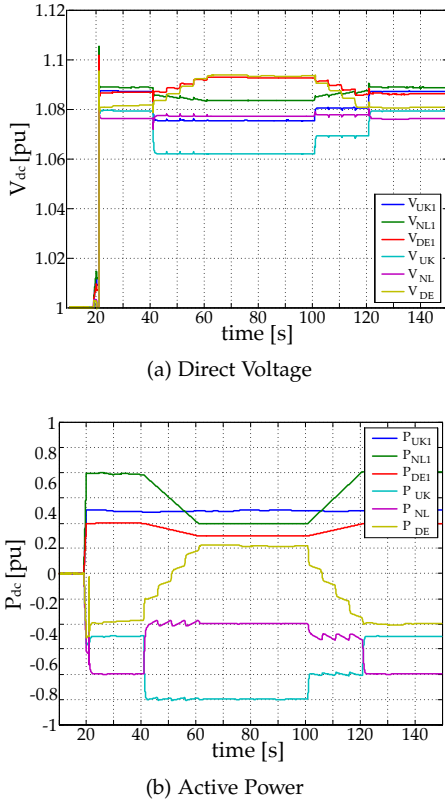


Figure 6.15: Results from scenario iii a.: Low wind scenario.

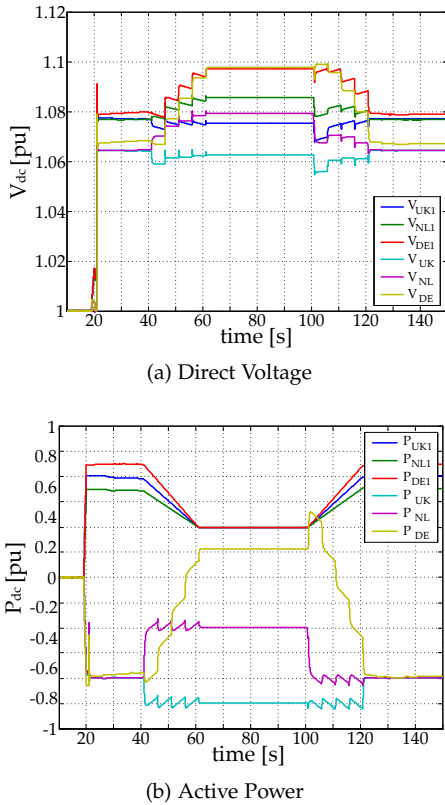


Figure 6.16: Results from scenario iii b.: High wind scenario.

needs to change to accommodate the curtailment. Nevertheless, even during the curtailment, the DVC strategy can control the power flow inside the MTdc network.

In fact, when the curtailment starts, the TSO changes the direct voltage set-points of the British and Dutch nodes to make each node receive, respectively, 1.0 pu and 0.4 pu of power, while the German node produces the additional 0.2 pu to compensate for some of the power that was curtailed.

The results of scenario iii-a show that the changes in power are both fast and smooth, while the MTdc system voltage is controlled within the limit of $\pm 10\%$ the rated value (see Figure 6.15). Meanwhile, the DVC strategy still guarantees that the MTdc network is operating with minimum losses for the chosen load flow operating point and that the system is N-1 secure. Finally, at $t = 100$ s, the OWF production is ramped back and the MTdc network is brought back to the initial operating point.

The results for the high-wind scenario (scenario iii-b) are shown in Figure 6.16. The total OWFs production in this scenario is 2.4 pu. In the beginning of the simulation, a sharing control strategy is being used (as in scenario ii-b), and each onshore node receives approximately 0.8 pu of power. The TSO then commands all OWFs to curtail their power to 0.4 pu from $40 \leq t \leq 60$ s. Once more, the total power production after curtailment is 1.2 pu. Therefore, the TSO can send new voltage set-points to the onshore converters so the UK and NL nodes receive 1.0 pu and 0.4 pu of power, respectively, while the DE node produces 0.2 pu. This load flow operating point can of course be arbitrarily chosen by the TSO, provided it respects the MTdc power balance and the onshore converters power ratings. At $t = 100$ s, the OWF production is restored to the initial values and the sharing control strategy is re-established.

AC Contingency: Scenario iv

The goal of the last scenario is to analyse the DVC strategy behaviour during a fault in one ac network node. The fault takes place in the ac-side of the UK onshore node. The response of the MTdc system to the fault are shown for two different wind scenarios: low-wind scenario (total generation is 1.8 pu), and high-wind scenario (total generation is 2.4 pu). The fault lasts 40 s, starting from $t = 40$ s to better visualise the transients involved when one MTdc network node is lost. Figure 6.17 and Figure 6.18 shows the active power and direct voltage for both scenarios. It also shows that the DVC strategy can successfully ride through the fault in both cases, although the dynamic response varies according to the wind scenario.

In the low-wind scenario, the sum of the remaining onshore converters rated power is lower than the power being produced offshore. Therefore, the MTdc network is N-1 secure and there is no need to change the OWF power output during the fault. In scenario iv-a, as seen in Figure 6.17, when the fault happens in the UK node, the

power at the Dutch and German onshore node rapidly changes to re-establish power balance in the dc grid. This occurs because all the GS-VSC are effectively controlling the dc system voltage, which is one of the DVC strategy greatest advantages. During this very fast transient, the MTdc voltage reaches a peak of 1.11 pu, but is quickly restored back to values within the operating limit. When the fault is cleared, at $t = 80$ s, the MTdc system voltage undergoes another transient, this time only a direct voltage dip to about 1.04 pu, which is much less of concern than the voltage spike when the fault occurs. Finally, at $t = 100$ s, the priority control strategy is reinstalled by the DVC strategy and the MTdc network goes back to its initial operating point.

Contrarily, in the high-wind scenario, the MTdc network is not N-1 secure since the total power being produced, 2.4 pu, is higher than the remaining onshore VSC combined ratings, which is 2 pu. In that case, the DVC strategy cannot alone keep the MTdc network voltage secure by increasing active power absorption at the onshore VSC terminals.

In scenario iv-b (see Figure 6.18), when the fault happens, dc choppers are activated on the DE and UK OWFs once the direct voltage exceeds 1.10 pu. Then, after the fault, the OWFs start to curtail their power outputs, which was not necessary before. Additionally, since in the high-wind scenario more power was being produced prior to the fault than in comparison with the low-wind scenario, the MTdc voltage transient peak is higher, with a maximum of 1.12 pu being reached at the UK offshore node.

Finally, when the fault is cleared, at $t = 80$ s, the offshore wind farm power output is kept constant for 20 seconds and then ramped up, starting from $t = 100$ s, to a new operating point, this time N-1 secure. A new load flow scenario is established from $t = 120$ s onwards.

Transmission Losses and Trade

The transmission losses and the power being traded in the MTdc network are shown in Figure 6.19 for all the analysed scenarios.

The MTdc transmission losses, $p_{losses}^{\%}$, given as a function of the total generated power at the offshore wind farms, and the power trade being traded in the MTdc network, P_{trade} are calculated as:

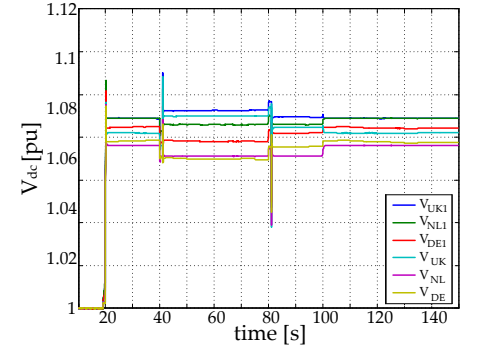
$$\begin{cases} p_{losses}^{\%} = 100 \sum_{j=1}^6 R_{dcj} I_{dcj}^2 / \sum_{j=1}^3 P_{dcj}^{owf} \\ P_{trade} = \frac{1}{2} \sum_{j=1}^3 (|P_{dcj}^{vsc} - P_{dcj}^{owf}|) \end{cases} \quad (6.21)$$

where;

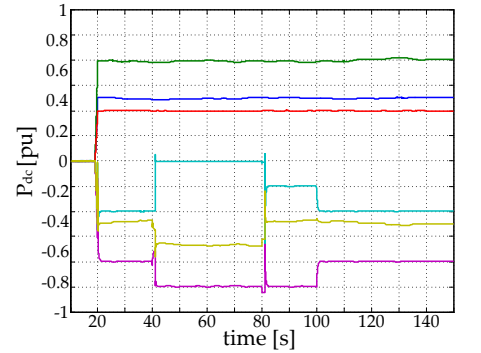
P_{dcj}^{owf} is the active power injected at the j-th OWF [W] and;

P_{dcj}^{vsc} is the active power of the j-th VSC [W].

The MTdc system losses are optimised by the GA, as this is its objective function. Figure 6.19 shows that the MTdc transmission

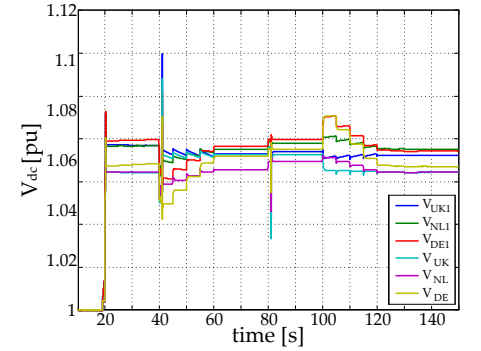


(a) Direct Voltage

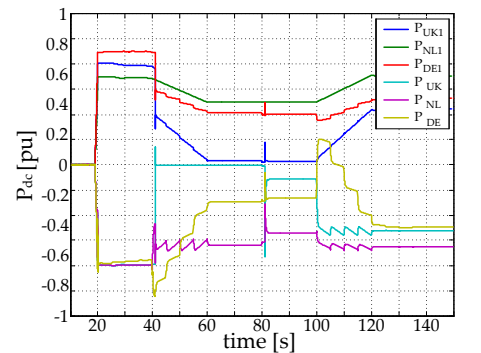


(b) Active Power

Figure 6.17: Results from scenario iv a.: Low wind scenario.



(a) Direct Voltage



(b) Active Power

Figure 6.18: Results from scenario iv b.: High wind scenario.

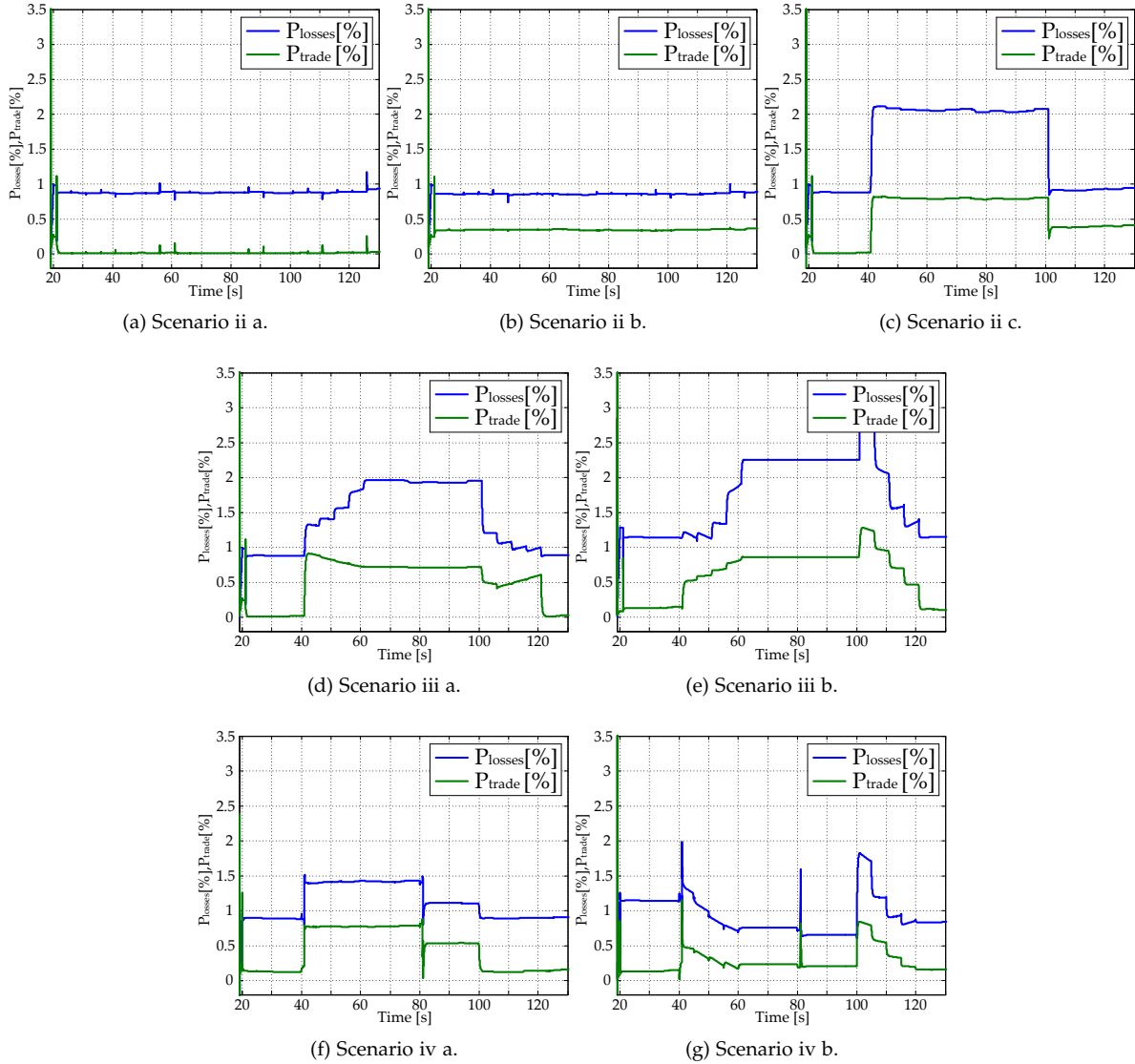


Figure 6.19: Transmission losses in the MTdc system in percentage of the total generated power and power traded in the MTdc system in per unit of the system power base.

losses vary between 1% and 3% of the total generated power. The total MTdc system losses will be higher since the VSC losses should also be taken into account.

It is interesting to note that the transmission losses and the power traded in the MTdc network have basically the same trend. This is due to the fact that the trade in the MTdc network – calculated by (6.21) – happens through lines 3 and 6, which are the longest lines.

6.4 DVC Strategy Telecommunication needs

When dealing with the communication needs for the DVC strategy, it is important to consider which technology will be employed to transmit the necessary data from the offshore wind farms to the central TSO and; after the optimal power flow is solved, from the central TSO to the onshore VSC terminals. Once the telecommunication

Technology	Pros	Cons
Microwave	The infrastructure implementation cost is low as there is no need to install physical means to cross space.	Transmission repeaters might be necessary, which could lead to the necessity of dedicated offshore platforms.
Satellite	Low implementation cost as all the needed infrastructure basically already exists.	Low data transmission speed and reliability, which can substantially impact the needed control cycle time.
Fiber Optics	Data reliability, low transmission time, mature industry for installation of offshore optic cables (several submarine cables already in operation).	The main downside of the fiber optics technology is cost. However, this could be overcome if it becomes integrated in the offshore HVdc cables.

Table 6.11: Comparison of different telecommunication technologies for implementation of the DVC strategy.

technology is chosen, the transmission mean can be modelled and the required transmission time can be straightforwardly obtained.

For the type of application considered, there are basically three different possibilities regarding the choice of telecommunication systems technology: micro-wave; satellite; and fiber optics telecommunication systems. Table 6.11 shows the advantages and disadvantages of the aforementioned telecommunication technologies.

Control Cycle Time - Information Traffic Time

In the DVC strategy, the information about the power being produced at the OWF has to be sent to the TSO central controller which will solve an optimal power flow (see Figure 6.20). Afterwards, the onshore VSC will set their direct voltage according to the reference point obtained from the TSO.

Therefore, knowing the amount of data to be sent, it is possible to calculate the total time needed to complete one control cycle. The calculations are done for the satellite transmission technology¹⁵.

The size of the data to be transferred is considered to be 14 MB, which is equivalent to an encrypted MATLAB file with 60 different ac and dc quantities measured at the offshore VSC with a sampling of 32 Hz for 15 minutes. The total time, T , to transmit the whole 14 MB data file can be calculated as:

$$T = n \cdot T_f \quad (6.22)$$

where;

n is the number of frames which need to be send and;

T_f is the time to send the frame and receive the delivery acknowledgement [s].

¹⁵ The employed method is general and, hence, can be repeated for the other options by adjusting the necessary parameters.

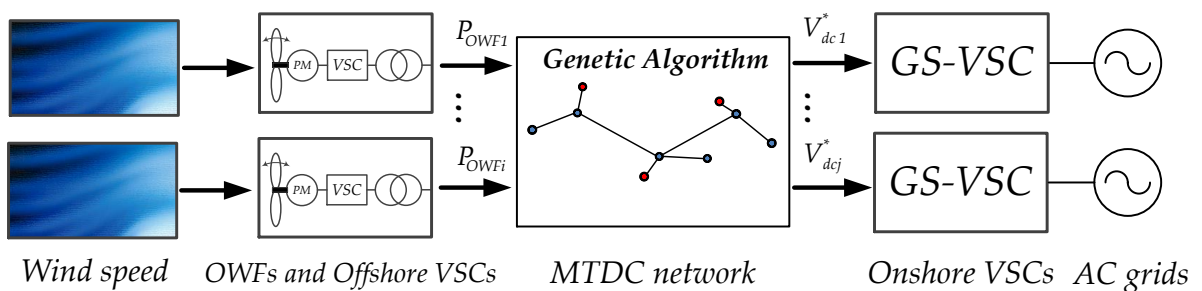


Figure 6.20: Information flow in the distributed voltage control strategy.

On the other hand, T_f can be calculated as:

$$T_f = t_{frame} + t_{prop1} + t_{proc1} + t_{ack} + t_{prop2} + t_{proc2} \quad (6.23)$$

where;

t_{frame} is the time needed to transmit one information frame [s];

t_{prop1} is the propagation time between the OWF and the TSO control centre [s];

t_{proc1} is the time for the optimisation algorithm to solve the OPF [s];

t_{ack} is the time for the receiver to acknowledge data delivery [s];

t_{prop2} is the propagation time between the TSO control centre and onshore VSCs [s] and;

t_{proc2} represents the time for the DVC controller to set the onshore VSC voltage to the received reference set-point [s].

In (6.23), t_{ack} and t_{proc2} can be disregarded. The first because the information frames are very small and the latter because the VSC can very fast track the direct voltage reference. On the other hand, t_{proc1} is known since it takes approximately 5 minutes for the genetic algorithm to solve a complete OPF problem. Thus, considering that t_{prop1} is approximately the same as t_{prop2} , (6.23) can be simplified as:

$$T_f = t_{frame} + 2 \cdot t_{prop} = \frac{L}{R} + 2 \frac{d}{v} \quad (6.24)$$

where;

L is the frame size [bits];

R is the transmission rate [bps];

d is the transmission distance [m] and;

v is the propagation speed [m/s].

Below the calculation of T_f – using (6.24) – is provided for the satellite technology.¹⁶

VSAT Satellite

In the satellite solution, each VSC terminal is equipped with a VSAT (Very Small Aperture Terminal) antenna. Commercial bandwidth values for data are circa 512 kbps, whereas the MTU (maximum transmission unit), i.e. the frame size, is taken equal to 1492 bytes, which is accordance with IEEE Ethernet standard 802.3 [176]. Since the data package is 14 MB, it holds that:

$$n = \frac{14 \text{ [MB]}}{1492 \text{ [bytes]}} = 9840 \text{ [frames]} \quad (6.25)$$

For a geostationary satellite $d = 2 \cdot 35786 \text{ km}$ – incoming and outgoing signal – whereas the propagation speed in air is taken equal the speed of light. The frame size L in bits is equal to 11936 bits (1492 bytes) and the transmission rate R in bps is equal 524288 bps (512 kbps). Therefore, for the satellite solution, (6.24) becomes:

$$\begin{aligned} T_f &= \frac{11936 \text{ [bits]}}{524288 \text{ [bps]}} + 2 \cdot \frac{2 \cdot 35786 \cdot 10^3 \text{ [m]}}{3 \cdot 10^8 \text{ [m/s]}} \\ &= 22.766 + 2 \cdot 238.57 \text{ [ms]} \approx 500 \text{ [ms]}. \end{aligned} \quad (6.26)$$

¹⁶Since the calculations are simplified, it may be that the obtained value of T_f using this approach can yield conservative values which are larger than what could actually be achieved in practice [175].

Substituting the obtained value of T_f into (6.22), the total control time cycles comes to:

$$\begin{aligned} T &= n \cdot T_f + t_{proc1} = 9840 \text{ [frames]} \cdot 0.500 \text{ [s]} + 300 \text{ [s]} \\ &= 5220 \text{ [s]} = 87 \text{ [min]} \end{aligned} \quad (6.27)$$

Therefore, a complete control cycle would take around 87 minutes to complete, which is higher than the usual 1-hour dispatch cycles for ac networks.

Fiber Optics

As seen from (6.26), when using satellite technology the propagation delay is what mostly determines the total control cycle time. Even if a higher satellite bandwidth was available, the 120 ms propagation time, due to the large distances involved, is the most limiting factor [175].

The same calculations performed for the satellite option can be done for a fiber optics transmission instead¹⁷. With this technology the propagation speed, v , can be considered equal to approximately 0.67c; while a nominal transmission rate, R , of 1 Gbps can be achieved if a direct connection is considered.

For the North Sea Transnational Grid, if the TSO control centre would be based in Amsterdam, the biggest involved distance in this case study would be circa 350 km from the UK onshore node [175]. For a conservative estimate, considering a bandwidth availability of 10 Mbps, the total control time cycle would be of:

$$\begin{aligned} T &= n \cdot T_f + t_{proc1} \\ &= 9840 \cdot \left(\frac{11936}{10485760} + 2 \cdot \frac{350 \cdot 10^3}{0.67 \cdot 3 \cdot 10^8} \right) + 300 \\ &= 345.47 \text{ [s]} \approx 6 \text{ [min]} \end{aligned} \quad (6.28)$$

Therefore, by using fiber optics, the total control cycle could be reduced from the 87 minutes cycle calculated with satellite technology to a much faster six minutes cycle. However, it is expected that the capital costs of the fiber optics solution would be higher than those for the VSAT antenna.

Nonetheless, if the amount of data to be transferred could be compressed to about 25% of the initial 14 MB, i.e. to around 3 MB, since not all data from the VSC terminal need to be transmitted for the DVC strategy to work, the total control cycle time involved with using satellite solution would come down to circa 25 minutes, making it a viable option and in line with the usual one-hour dispatch cycles for ac networks. In contrast, the total control cycle time for the fiber optics solution would not change as much, since the computational time of the optimisation algorithm is the main restricting factor [175].

¹⁷ It is likely that offshore-installed VSC transmission stations will have fiber optics integrated into the submarine HVdc cables [177].

6.5 Control and Operation of a Large MTdc Network (Case Study 3)

The DVC control strategy has been successfully applied to control small MTdc networks with five VSC-HVdc terminals (case study 1) and with six terminals (case study 2).

In this case study, the performance of the DVC strategy in operating a large meshed MTdc network is tested via numerical simulations. The MTdc network layout is depicted in Figure 6.21. This is the same network layout which was used in Chapter 3 when the dc load flow algorithm was presented (see Figure 3.12) [178].

The MTdc network is composed of 19 nodes, interconnecting nine OWFs to five different onshore ac networks representing each a northern European country; namely, The United Kingdom, Belgium, the Netherlands, Germany and Denmark. Five nodes are hub nodes, which means there are no converters installed in these locations and their main function is to allow for cable joining. Table 6.12 shows the names and the sizes of the wind farms included in the study.

Table 6.13 describes the transmission lines in the MTdc network. It shows the line length in kilometers and also the installed capacity of the departing node VSC. For instance, Table 6.13 shows that the VSC installed at UK1 is rated at 3 pu, whereas the one at UK2 is rated at 2 pu and the UK onshore VSC is rated at 5 pu.

The dc cables rated power is chosen to match the rated power of the nodes that they are connected to. In this way, the dc cables have either the installed capacity of their respective OWF or onshore node. An exception is made for the dc cables interconnecting the hubs, which have an installed capacity of 1 pu.

Table 6.12: Offshore wind farms included in the dynamic simulations of case study 3.

Wind Farm	Node	Size [pu]
Doggersbank	UK1	3
Hornsea	UK2	2
Thorntonbank	BE1	1
IJmuiden	NL1	2
Eemshaven	NL2	1
Hochsee Sud	DE1	2
Hochsee Nord	DE2	2
Horns Rev	DN1	1
Ringkobing	DN2	1

Table 6.13: MTdc network lines considered in case study 3.

Line Start	Line End	Length [km]	Size [pu]
UK1	HUB1	100	3
UK2	HUB1	40	2
UK	HUB1	120	5
HUB1	HUB2	300	1
BE1	HUB2	50	1
BE	HUB2	100	1
HUB2	HUB3	120	1
NL1	HUB3	100	2
NL2	HUB3	40	1
NL	HUB3	70	3
HUB3	HUB4	250	1
DE1	HUB4	40	2
DE2	HUB4	70	2
DE	HUB4	150	4
HUB4	HUB5	120	1
DK1	HUB5	40	1
DK2	HUB5	50	1
DK	HUB5	150	2
HUB1	HUB5	380	1

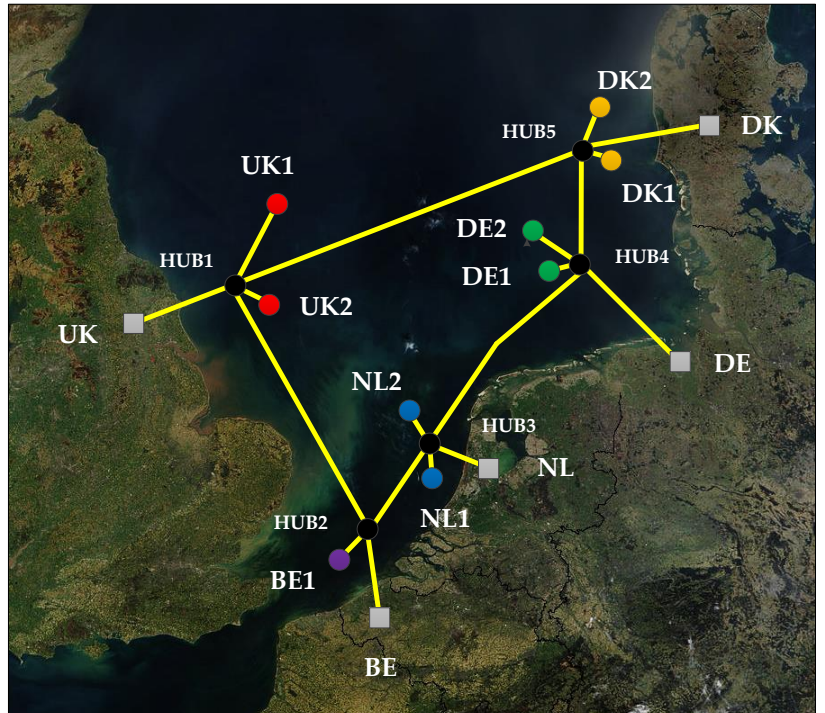


Figure 6.21: The 19 node meshed VSC-MTdc network used in the simulations [178].

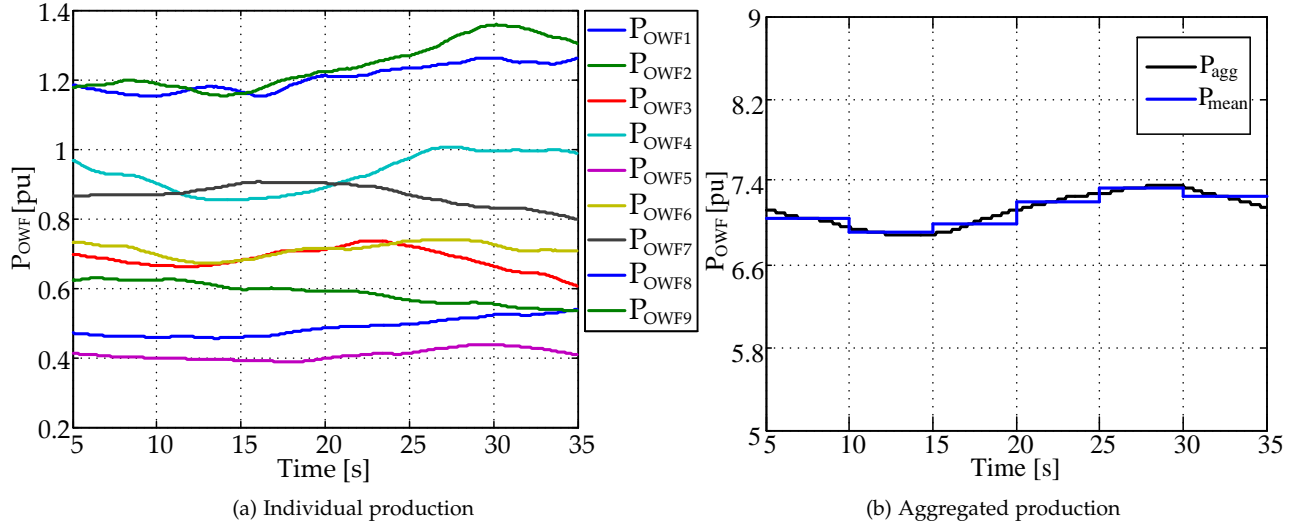


Figure 6.22: Wind farms power production during the case study.

As previously mentioned, there are 9 OWFs installed in the MTdc network and their aggregated installed capacity is 7.5 GW, or 15 pu in the system base power (see Table 6.14). The dc system voltage is of ± 320 kV and all the onshore VSCs are assumed to be connected at ac substations with short-circuit ratio three times higher than the converter installed capacity.

In this case study, real wind data is used to represent the power production of the different OWFs. The wind data measured from a single wind turbine is smoothed to simulate the power production of a complete offshore wind farm [178,179]. Figure 6.22 displays the OWFs power production during the simulation. The wind power production curves are plotted in the system power base as given in Table 6.14. The three different scenarios analysed in the thesis are described in detail in Table 6.15.

In all case studies a three-phase fault was applied in the ac grid of the British converter station. The fault occurs at $t = 25$ s and is cleared after one second. The fault lasts for a complete second to show that, when a converter station is lost, the system is able to reach a new feasible operating point after transients decay [178].

Table 6.15: Description of the analysed scenarios in case study 3.

Scenario	Description
i	The MTdc network will be controlled according to a flat voltage profile, i.e. all the onshore VSC voltage references are set to 1.0 pu.
ii	The MTdc network voltage references are set to minimise the power losses during the entire simulation.
iii	In the first part ($5 \leq t \leq 10$ s), priority in receiving power is given to the UK and Germany. The UK is willing to receive 1.5 pu and Germany 2 pu. In the second part ($10 \leq t \leq 20$ s), the VSC voltage references are set such that Belgium will receive 1 pu; while the Netherlands and Germany will receive 2 pu each. In the last part ($t \geq 20$ s), the Netherlands and Denmark will receive 1 pu of power each.

Table 6.14: Parameters of the MTdc network analysed in case study 3.

Parameter	Value
System Base Power (S_b)	500 MVA
AC Grid Short Circuit Ratio (SCR)	3 pu
AC Grid HV Side Voltage (E_L)	380 kV
OWF Collection Voltage (V_{owf})	33 kV
VSC Voltage (V_c)	275 kV
Trafo Impedance (z_t)	$0.005 + j0.100$ pu
VSC Filter Size - AC Grid (S_f)	200 MVA
VSC Filter Size - OWF (S_f)	50 MVA
Phase reactor Impedance (z_c)	$0.003 + j0.150$ pu
VSC DC-side Capacitor (C_{dc})	$75 \mu\text{F}$
MTdc Network Voltage (V_{dc})	± 320 kV
DC Cable Resistance (r_{dc})	$0.0195 \Omega/\text{km}$
DC Cable Inductance (l_{dc})	$19 \text{ mH}/\text{km}$
DC Cable Capacitance (c_c)	$220 \text{ nF}/\text{km}$
DC Cable Cross Section (A_{dc})	2200 mm^2
DC Cable Rated Current (I_{dc})	2.086 kA

Results

The case studies described in Table 6.15 were analysed using the models developed in Chapter 4. The ac grids were modelled as ideal voltage sources behind short circuit impedances, and the MTdc network is modelled as lumped impedances in a state-space matrix representation [146,149]. The VSC model employed is an averaged model which includes the dynamics of the controllers but neglects the switching phenomena. The OWFs were modelled as current sources with the output power given in Figure 6.22 [180].

The transmission losses comparison between the three analysed cases is displayed in Figure 6.23. The MTdc network voltages are shown in Figure 6.25, whereas the actual active power at the onshore nodes is given in Figure 6.24.

No optimisation: Scenario i

As described in Table 6.15, during the first scenario, the MTdc network is controlled with a flat voltage profile. In that case, the MTdc network losses stay at around 2.75% of the OWFs produced power. The first column in Figure 6.25 displays the MTdc network onshore node voltages, while the upper plot in Figure 6.24 shows the onshore nodes dc power for Scenario i.

As seen from the results, all onshore VSCs are able to keep the direct voltage constant at 1 pu by slowly varying the input dc power according to the variations at the OWFs side. However, in this scenario the load flow distribution is not controlled and it is not assured whether the MTdc network is N-1 secure.

Losses optimisation: Scenario ii

From the transmission losses optimisation results, displayed in Figure 6.23, it is straightforward to realise that the MTdc network losses are only marginally, circa 0.1%, lower than the case with no optimisation. The dc system voltages and active power for the flat profile are very close to the optimal load flow found in scenario ii (see Figure 6.24).

To minimise the transmission losses, the DVC reaches a load flow scenario with higher direct voltage values, circa 1.02 pu. In this way, the transmission power losses are slightly decreased. Additionally, with higher voltages it is expected that the converter losses would also decrease. Finally, the system security is enhanced, since the DVC assures that the network is N-1 secure.

Controlled Power Flow: Scenario iii

In this last scenario, the power flow inside the MTdc network is controlled according to the specifications given in last row of Table 6.15. The lower plot in Figure 6.24 shows that the DVC strategy has correctly set the onshore node voltages to establish the desired power

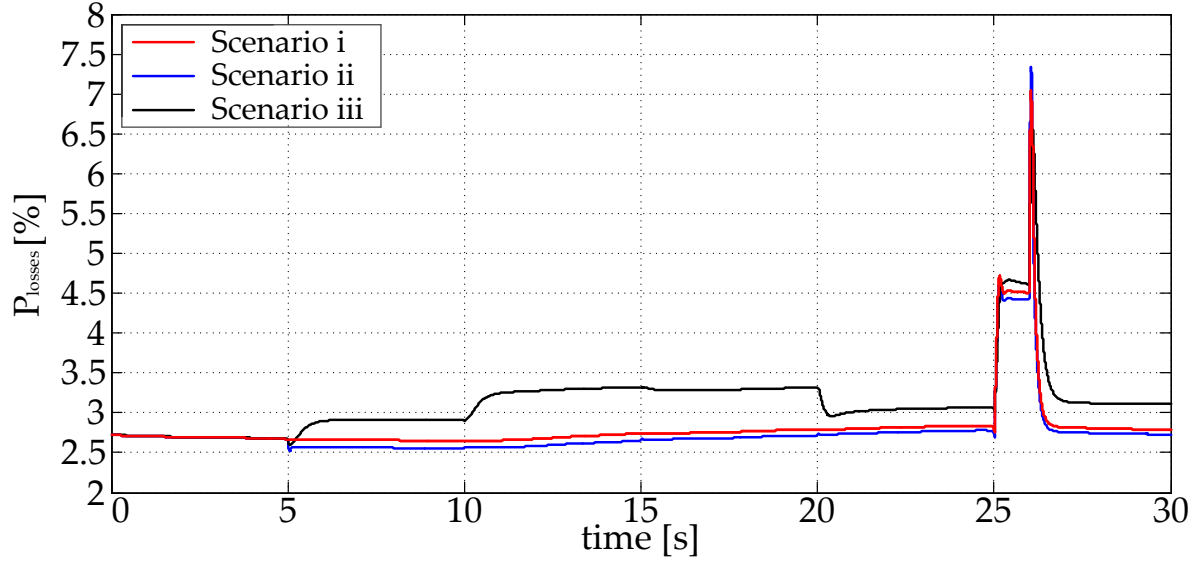


Figure 6.23: Transmission power losses during for the three scenarios in case study 3.

flow, even though the optimal dc power flow implemented works over the wind power production averaged over 5 seconds.

To control the power flow inside the MTdc network, the DVC controller varies the dc system voltage at the onshore nodes. The last column of Figure 6.25 displays the variations in the direct voltages; which, for the analysed case, always lie inside the operational margin of $\pm 10\%$ the rated value.

Additionally, changes from one load flow operating point to another are accomplished in less than 200 ms, due to the fast control capabilities of the onshore VSC terminals.

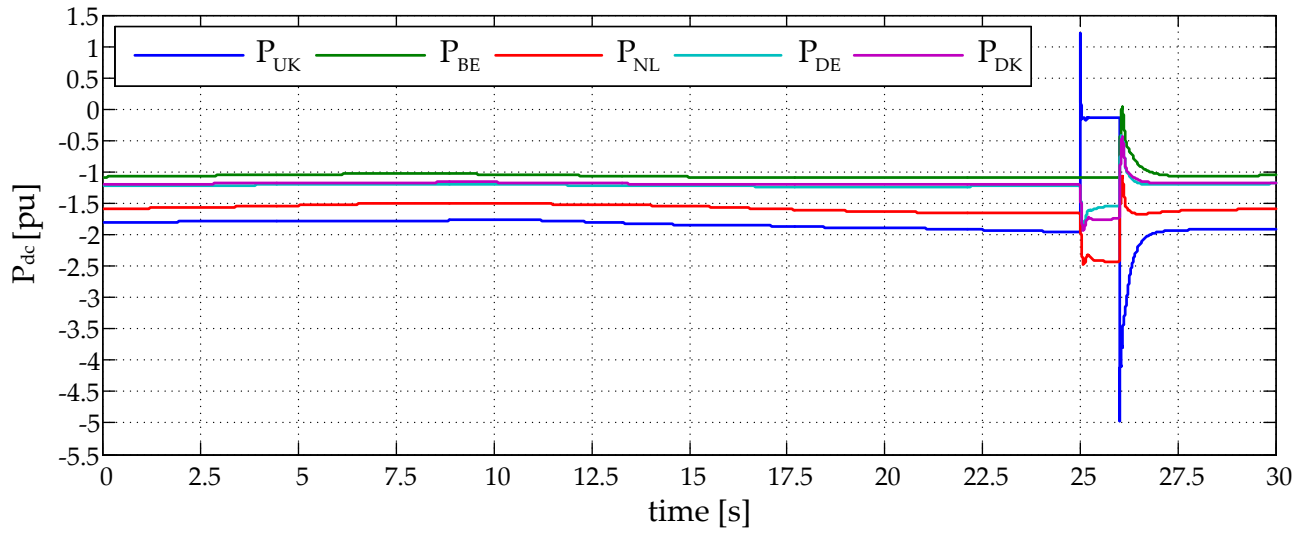
As the optimisation goal in this last scenario is to minimise the system losses while still respecting the load flow constraints set by the TSO, the obtained transmission losses are higher than the in scenario ii due to the extra constraints (see Figure 6.23).

Nevertheless, the results shown in the right column of Figure 6.25 demonstrate that the onshore VSC stations are able to withstand the onshore ac three-phase fault at the British station while keeping the power balance inside the MTdc grid [178].

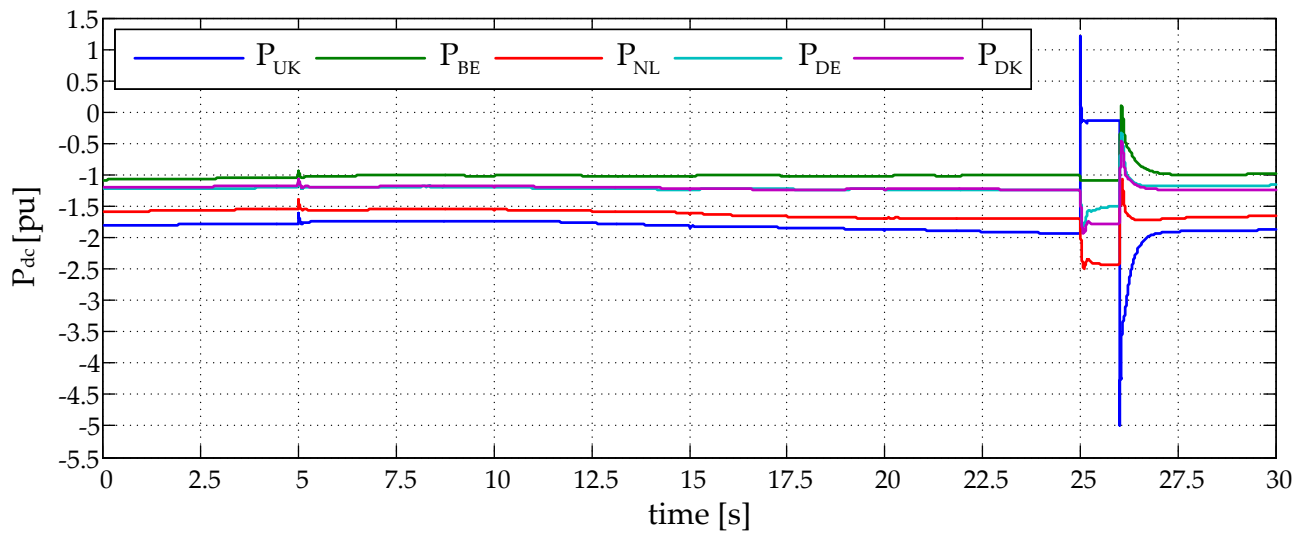
Between $25 \leq t \leq 26$ s, the power flow inside the network is not optimised to minimise the power losses. However, the inclusion of the N-1 security algorithm in the DVC strategy guarantees that, in steady-state, the converter stations rated power is respected. Additionally, the steady-state direct voltages inside the MTdc network are kept under the pre-established 1.10 pu limit during the N-1 contingency.

During the fault, the British onshore and offshore nodes are, as expected, the ones that suffer the highest direct voltage variations, as the British onshore converter station cannot receive power. The remaining onshore nodes present lower variations due to their higher distance to the fault¹⁸. After fault clearance, at $t = 26$ s, the onshore stations are able to once again operate under the TSO desired power flow.

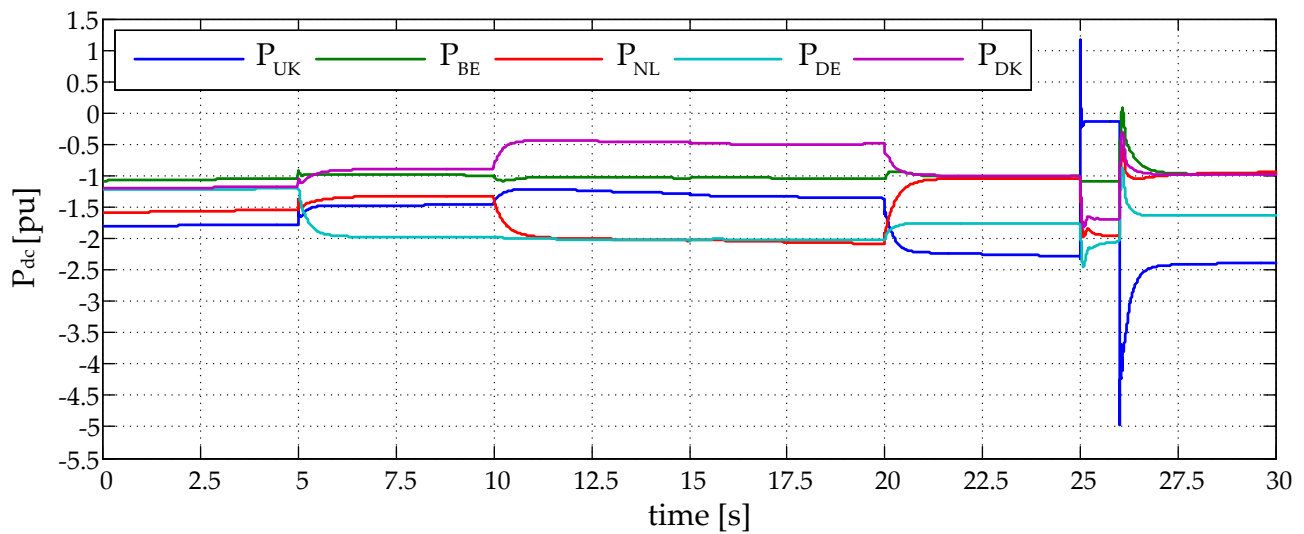
¹⁸ The Belgian onshore node does not alter its power transmission during the fault as it was previously at its maximum transfer capacity of 1 pu. The Dutch onshore VSC station was the node that increased the most its power reception, from circa 1.5 pu to 2.5 pu because the Netherlands is the closest onshore node to UK with available power capacity. The remaining two countries, Denmark and Germany, also increased their power consumption to maintain the direct voltage stable inside the MTdc network.



(a) Scenario i



(b) Scenario ii



(c) Scenario iii

Figure 6.24: Active power at the onshore nodes for the three scenarios in case study 3.

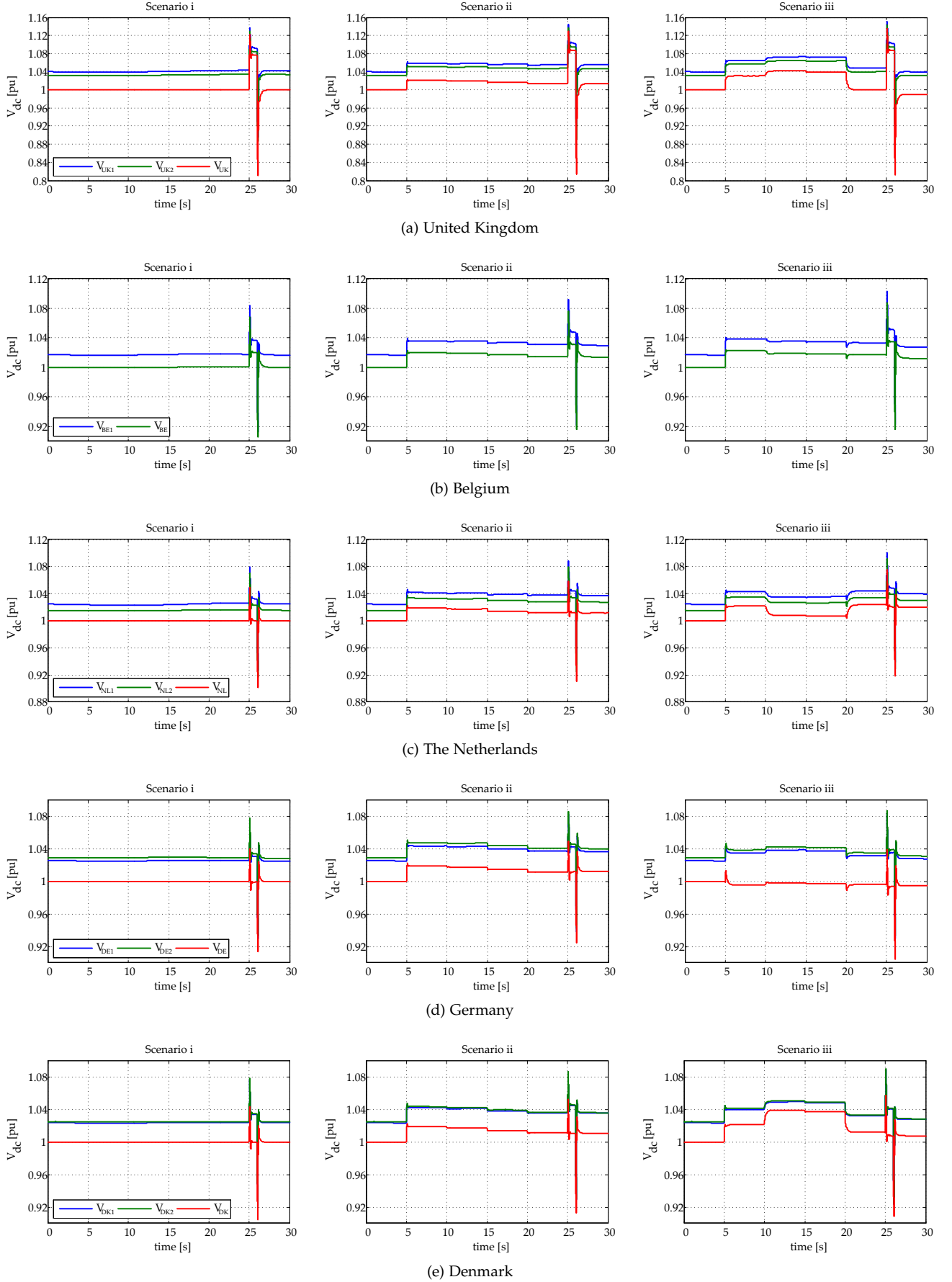


Figure 6.25: Direct voltage at the OWFs and onshore VSC terminals for the three scenarios in case study 3.

6.6 Conclusion

The distributed voltage control strategy is readily expandable to larger MTdc networks, and more nodes controlling the network direct voltage will add more flexibility to the method.

In the DVC strategy, network nodes which are not directly connected to generating plants work as slack nodes controlling the MTdc network voltage. This increases the system resilience against ac faults, and it additionally provides a higher flexibility, i.e. ability to control the power flow inside the system, by finding a solution to an optimal power flow problem. The OPF problem can be solved to minimise systems losses, or maximise the network social welfare – or even have multi-objective optimisation goals – all while guaranteeing that a certain power flow scenario, set by a transmission system operator will be respected in a N-1 secure dc network.

Independently from the optimisation algorithm used to solve the OPF problem, the DVC strategy principle remains the same: to output the direct voltage references to VSC-HVdc stations controlling the MTdc network voltage based on knowledge of the system generation.

The DVC needs telecommunication to receive information on the system generation, to receive commands from the system operator, and to assign the direct voltage to network slack nodes. As this communication can happen in control cycles in the order of minutes, fast telecommunication links although desirable are, in principle, not needed.

A total of three case studies, using the dynamic models developed in Chapter 4, demonstrated that the DVC strategy is capable of reliably and safely controlling the power flow in large MTdc networks with good dynamic performance. Table 6.16 contains a comparison between control strategies presented in Chapter 5 and the DVC strategy.

The distributed voltage control strategy will be validated in Chapter 9 through the development of a low-voltage MTdc network setup in the power electronics laboratory of TU Delft.

Table 6.16: Comparison between control strategies presented in Chapter 5 and the DVC strategy.

Control Method	Droop	Ratio	Priority	Voltage Margin	DVC
Dynamic Response	High	High	Medium	Low	High
Expandability	Medium	Low	Medium	High	High
Flexibility	Low	Medium	Medium	High	High
Communication Requirement	Low	Medium	Low	Medium	Medium

Part IV

Stability Analysis

7

Fault Analysis

It happens. Sometimes.

Tom Hanks - Forest Gump

The steady-state effects of ac faults on MTdc networks were introduced in Chapter 3. In Chapter 5 and Chapter 6, the dynamic response of the direct voltage controllers in scenarios with ac contingencies were present in all case studies. If multi-terminal dc networks are to be developed, they will need to withstand contingencies both on the ac part, and the dc part of the transmission system, preferably without halting normal operation after fault clearance. This chapter investigates, using the dynamic models from Chapter 4, what is needed for a MTdc network to successfully recover after a contingency scenario. At first, the effects of ac-side contingencies on a MTdc network are analysed. During the ac contingencies, the focus is on the ability of VSC-HVdc stations to satisfy the grid code requirements while maintaining the dc network safety. The results provide a basis for a discussion on ac grid code requirements efficacy.

Next, the possible dc-side contingencies – which will be extremely challenging for MTdc networks – are characterised and examined. A comparison is performed on how dc faults affect a MTdc network depending on the HVdc transmission system configuration. Based on the converters natural fault response to a dc fault, a methodology is presented on how to select a dc breaker technology and establish whether dc limiting reactors are necessary. For clearing the dc faults, four different dc breaker technologies are compared based on their fault interruption time, together with a current direction fault detection method. Finally, recommendations are made on how to protect the MTdc networks against dc faults.

- 7.1. Grid Code Requirements
- 7.2. VSC-HVdc Capability Chart
- 7.3. VSC-HVdc Grid Code Compliance in MTdc Networks
- 7.4. AC-side Contingencies
- 7.5. DC-side Contingencies
- 7.6. DC Breaker Technologies
- 7.7. Protection of MTdc Networks
- 7.8. Conclusion

This chapter is based on the following publications:

- R. Teixeira Pinto, S. F. Rodrigues, P. Bauer, and J. Pierik, "Grid Code Compliance of VSC-HVDC in Offshore Multi-terminal DC Networks," in *39th Annual Conference of IEEE Industrial Electronics Society (IECON)*, Vienna, Austria, July 2013, pp. 1-5.
- E. Kontos, R. Teixeira Pinto, S. F. Rodrigues, and P. Bauer, "Impact of HVDC Transmission System Topology on Multi-Terminal DC Network Faults," *Submitted to IEEE Transactions on Energy Delivery on October 14th*, pp. 1-8, 2013.

7.1 Grid Code Requirements

As wind turbine development continues, with 5-MW units already available, 7-MW units to debut, and 10-MW ones under development, wind farms are expected to grow in installed capacity [135, 181]. Hence, regardless whether onshore or offshore, to connect to the transmission system, large wind farms are required by TSOs to comply with grid codes as normal power plants do [182,183]. In case of large offshore wind farms, special amendments may apply [184].

Concomitantly, for large and distant offshore wind farms, HVdc transmission systems will have to be deployed to transmit the generated energy to shore¹. As in Northern Europe an offshore dc network is envisioned to integrate large amounts of wind power, and boost electricity markets, grid codes are a vital aspect for the integration of the different national electricity networks [185].

To ensure a securely operating network, the TSO usually establishes a set of rules for the connection of large generating facilities to the transmission grid. This set of rules is known as the grid code. In the past, wind farms were not required to strictly fulfill the grid codes requirements. Nowadays, specially in countries where the wind power penetration is rapidly increasing, large wind farms are required to actively participate in the power system control, both frequency and voltage, just as any conventional power plant [182,183].

It is known that grid code requirements have been a major force on wind turbine development. However, manufactures often claim that these requirements are extra demanding and have influenced the turbine development process [186]. The same phenomenon could affect the development and operation of a multi-terminal dc network for the integration of offshore wind power. If the grid code requirements for offshore connections are made too demanding, it might become difficult to guarantee proper operation of the MTdc network during atypical operating conditions at one of interconnected the ac networks.

For the successful development of offshore MTdc networks, it is imperative that any kind of contingency in one ac network node is not propagated to the remaining nodes, via the dc connection [187]. When an OWF is connected via a dc transmission system, the responsibility to comply to the grid code requirements is passed to the onshore HVdc station, and the OWF is decoupled from the ac network. Herewith, the major and most important requirements for the connection of large wind farms are here presented and discussed [188]².

Frequency operating range

Large wind farms are also required to provide primary and secondary frequency response. When the ac grid frequency deviates from its nominal value, wind farms are allowed - or required to - disconnect from the system, but only after a time delay.

¹ Some of the HVdc transmission systems built for the connection of large offshore wind farms are presented in Table 3.4.

² The first three sections of the present chapter deal with the following topics: the most common grid code requirements (GCR) for the connection of offshore wind farms; an analysis of the VSC-HVdc systems capability chart to check if they are able to satisfy the grid codes; and, lastly, dynamic simulations. The capability chart is key to understanding how can voltage-source converters can comply with grid codes. The VSC ability to fulfil the grid code requirements is important for understanding how these requirements impact the operation of dc networks when several converters become interconnected. Finally, the dynamic simulations demonstrate that strict grid codes can have an impact on the operation of MTdc networks.

An example is taken from the German TSO, E.ON Netz: for frequencies above 53.5 Hz and below 46.5 Hz, offshore wind farms must be automatically disconnected only after 300 ms. For other frequency values inside this range, they must stay connected for at least the time period indicated in [184] (see Figure 7.1).

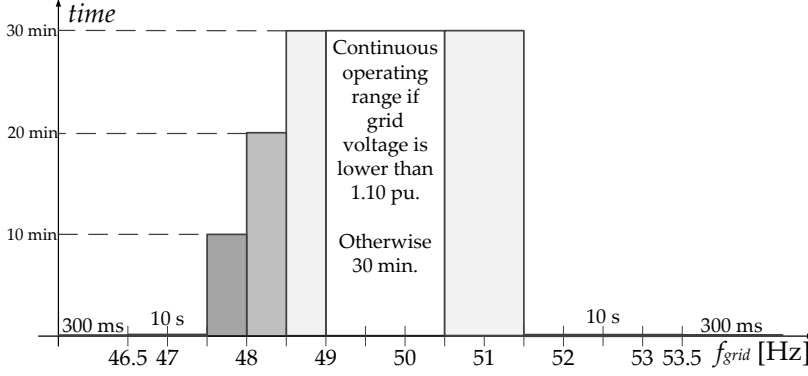


Figure 7.1: Frequency operating range as according to the German TSO, E.ON Netz [184].

Active power control

Large wind farms are also required to participate in the ac network control, and provide primary and secondary frequency response. Hence, they must be able to vary their active power output according to set points provided by the TSO [186]. Usually the new set point has to be achieved with a minimal rate of change, G_p , such that:

$$G_p \geq \frac{P_{ac1} - P_{ac0}}{t_1 - t_0} \quad (7.1)$$

where;

G_p is the active power gradient [W/s];

P_{ac1} is the new active power target [W];

P_{ac0} is the present active power [W];

t_0 is the time in which the transient started [s] and;

t_1 is the time the transient finishes.

Additionally, wind farms should also automatically reduce their active power when the system frequency exceeds the normal operating area. The active power curtailment as a function of frequency is given as:

$$P_{ac1} - P_{ac0} = \Delta P_{ac} = -G_f(f^{lim} - f) \quad (7.2)$$

where;

ΔP_{ac} is the required active power curtailment [W];

G_f is the curtailment slope [W/Hz];

f^{lim} is the frequency upon which curtailment should start [Hz] and;

f is the ac network frequency.

Moreover, the TSO can also set a time frame within which the curtailment given by (7.2) needs to be achieved.

Reactive power control

Wind farms are required to help regulating the grid voltage by varying their reactive power exchange with the ac network. Usually, different TSOs have different requirements for the reactive power exchange as its effectiveness depends on the connection voltage level, and the network characteristics.

Depending on the grid code, the specifications for the reactive power control might be given as a voltage range, a reactive power range, or a power factor (PF) range at the point-of-common coupling (PCC) [189]. For instance, during normal operation, the Polish TSO³ defines the PF range as, $0.975 \text{ ind} \leq \cos\phi \leq 0.975 \text{ cap}$, whereas the Australian TSO⁴ defines it as, $0.93 \text{ ind} \leq \cos\phi \leq 0.93 \text{ cap}$, for all the wind farm active power capacity [186].

³ PSE: Polskie Sieci Elektroenergetyczne.

⁴ NEMMCO: National Electricity Market Management Company.

Reactive current supply during voltage dips

In addition to the reactive power control during normal operation, e.g. $|e_{grid} - e_{nom}| \leq 0.10 \text{ pu}$, some TSOs also define rules for reactive current injection during voltage dips and/or swells, to help restoring the grid voltage to its normal range. The amount of reactive current to be supplied is usually defined as a function of the network voltage. Figure 7.2 (a) shows the reactive current requirement for Spanish wind farms [190].

Fault ride through requirement

⁵ Also known as low-voltage ride through (LVRT).

The fault ride through (FRT) requirement⁵ specifies the maximum amount of time during which the wind farms should withstand low voltages in the ac network, due to a contingency, without disconnecting from the transmission grid. This requirement is usually provided by the TSO as a voltage level at the PCC high-voltage side as a function of time [191]. Figure 7.2 (b) shows the FRT requirement for the German TSO E.ON Netz [184]. Additionally to the FRT requirement, most TSOs also set requirements for the reestablishment of the active power after the fault with a minimum rate of change as defined in (7.1).

The FRT characteristic curve is composed of 4 main areas: in the white part of the diagram wind farms should not disconnect from the network. In the light gray area, short term interruptions (STI) are allowed provided they last for less than 300 ms, and in the dark gray area STI are allowed up to 2000 ms.

⁶ NGET: National Grid Electricity Transmission.

Finally, in the black area, disconnection of the wind turbines is allowed by means of an automatic system. For instance, the United Kingdom TSO⁶, establishes that for dip durations up to 140 ms, the active power must be restored to 90% of the pre-fault level within 500 ms after the grid voltage returns being higher than 90%.

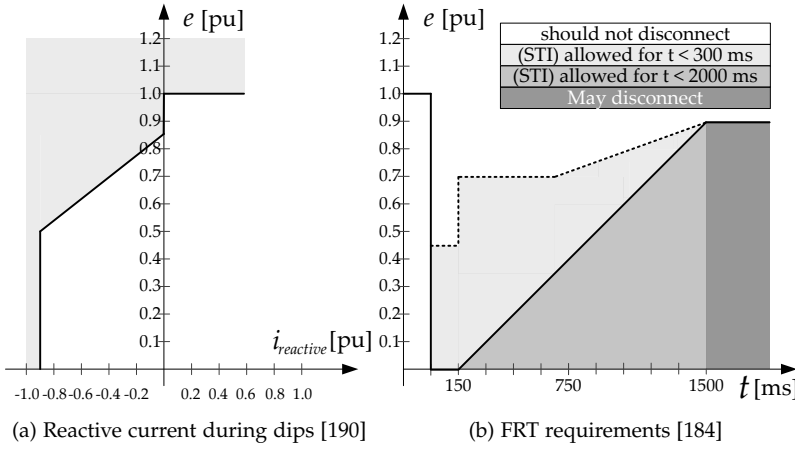


Figure 7.2: Typical fault ride through requirements

7.2 VSC-HVdc Capability Chart

The ability of a VSC-HVdc station to comply with the grid code requirements will depend on its capability to remain connected to the ac grid in the given frequency operating range, and to control the active and reactive power flow during sound and contingency conditions [188]. The converter active and reactive power flow operating range is given by its capability chart. The power flow between two nodes is used as a starting point for studying the VSC-HVdc capability chart.

The phasor diagram of the two-node network is given in Figure 7.3 (a), together with the resulting power flow according to the relative location between the voltage phasors, given in Figure 7.3 (b). Figure 7.4 contains a single phase representation of the two-node network.

The voltage at the VSC node, v , is given by a bi-quadratic equation:

$$v^4 + [2(r_T p_c + x_T q_c) - e^2] v^2 + (r_T^2 + x_T^2) (p_c^2 + q_c^2) = 0 \quad (7.3)$$

where;

v is the VSC voltage [pu];

e is the ac network voltage [pu];

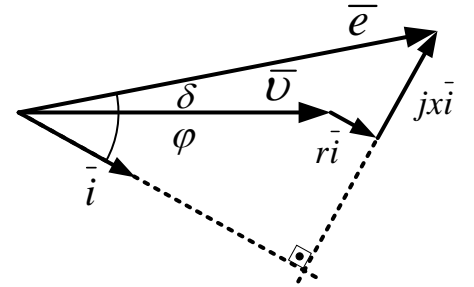
r_T is the total resistance between the VSC and the ac grid [pu];

x_T is the total reactance between the VSC and the ac grid [pu];

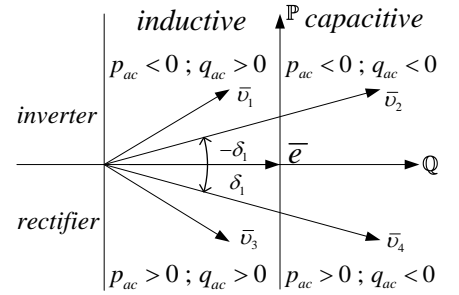
p_c is the VSC active power [pu] and;

q_c is the VSC reactive power [pu].

To meet the desired active and reactive power scheduling, the VSC-HVdc control system will vary the current through the connection impedance by changing its voltage \bar{v} . There is, however, a maximum power that can be exchanged between the two nodes. As the VSC-HVdc can control the active and reactive power independently, its power factor is known. Substituting $q_c = p_c \tan \phi$ into (7.3)



(a) phasor diagram



(b) Power flow direction

Figure 7.3: Phasor diagram of the two-node network.

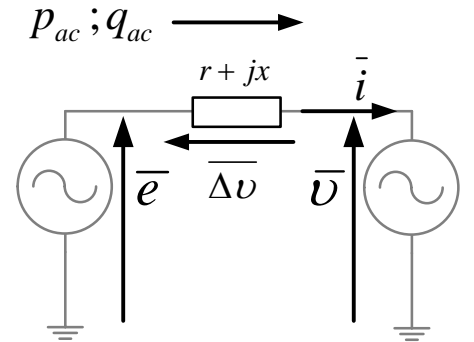


Figure 7.4: Single phase representation of the two-node network. The left-hand side node is the ac grid, whereas the right-hand side is the VSC-HVdc station.

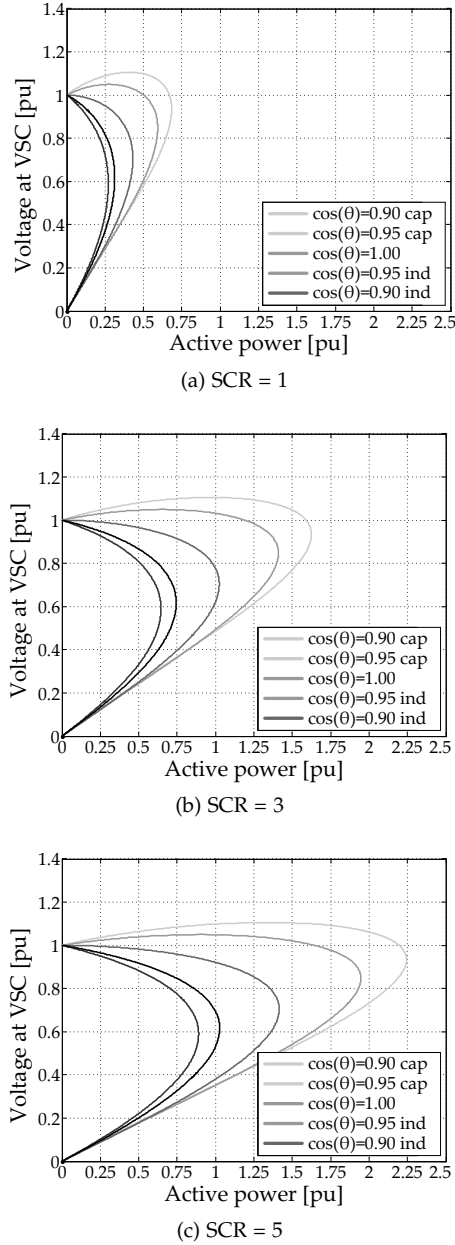


Figure 7.5: Receiving node voltage as a function of active power for different short circuit ratio and power factors.

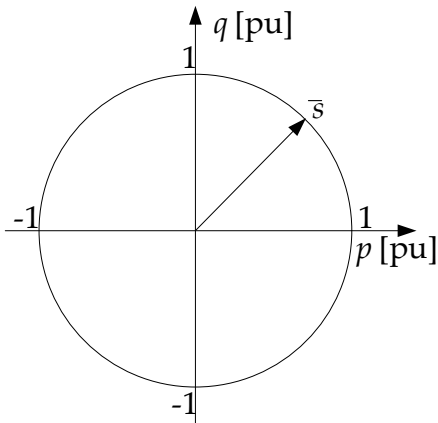


Figure 7.6: VSC-HVdc ideal capability chart.

and rearranging with respect to p_c , yields:

$$\left[(r_T^2 + x_T^2) \sec^2 \phi \right] p_c^2 + \left[2v^2(r_T + x_T \tan \phi) \right] p_c + (v^4 - (ev)^2) = 0 \quad (7.4)$$

Figure 7.5 shows a series of curves, known as nose curves, for the receiving node voltage as a function of the transmitted active power between the two nodes for different power factors and short-circuit ratios ($SCR = S_{ac}/S_{vsc}$).

The active and reactive power can be precisely controlled in a VSC-HVdc transmission system. Moreover, as shown in Figure 7.3 (b), within its rated power, the VSC is able to operate, at least theoretically, in any given point of its P-Q diagram or capability chart. Therefore, the VSC capability chart is, in principle, a circle with the converter apparent power rating, in MVA or pu, corresponding to the circle radius (see Figure 7.6) [32,46].

However, the real P-Q diagram will be limited by the following practical factors [192]:

1. The maximum reactive power the converter can absorb from the ac network ($q_c > 0$) is limited by the network stability limit and it is given by the critical frontier;
2. The maximum reactive power the converter can inject in the ac network ($q_c < 0$) is limited by the maximum possible direct voltage level. The transmitted reactive power depends on the difference between of the ac network voltage and the fundamental component of the VSC output voltage, which, in turn, depends on the direct voltage level;
3. There is a limit to the maximum transferable active power, due to the ac network stability limits and due to thermal limits of the dc cable and of the VSC converter, i.e. the maximum allowable current through the system.

Critical Frontier

All the nose curves shown in Figure 7.5 have a point where the transmitted active power is maximum, which corresponds to the maximum load angle, $\delta = \pi/2$. The maximum power is transmitted when the inflexion of $p_c = f(v)$ changes, while all the other parameters – e, x_T, r_T, ϕ – are held constant. The inflexion point changes when:

$$\frac{\partial p_c}{\partial v} = 0 \quad (7.5)$$

To satisfy (7.5), it is sufficient to make the discriminant of the bi-quadratic equation (7.3) equals to zero, i.e.:

$$\left[2(r_T p_c + x_T q_c) - e^2 \right]^2 - 4(r_T^2 + x_T^2)(p_c^2 + q_c^2) = 0 \quad (7.6)$$

Since, for HVac networks, usually $r_T/x_T \ll 1$, the resistive part of the total impedance between the VSC and the ac network can be disregarded. Hence, solving (7.6) for q_c , yields:

$$q_c = \frac{e^2}{4x_T} - \frac{x_T}{e^2} p_c^2 \quad (7.7)$$

which is known as the critical frontier between the transmitted active and reactive power.

Figure 7.7 shows the critical frontier for the two-node network as a function of the short-circuit ratio between the nodes. It is important to note that operating points above the critical frontier are not feasible. Therefore, the ability of the receiving node to absorb reactive power is limited, as beyond the critical frontier the ac network voltage becomes unstable and collapses.

Maximum Direct Voltage Level

The capability of the VSC-HVdc to inject reactive power into the ac system is limited. This restriction happens since there is a limit to the maximum amplitude of the converter fundamental voltage, which depends on the converter direct voltage level and modulation technique [32]. To understand the influence of the alternating voltage amplitude on the VSC-HVdc capability chart, it is possible to start by writing the apparent power at the ac system node:

$$\bar{s}_{ac} = p_{ac} + jq_{ac} = \bar{e}\bar{i}^* \quad (7.8)$$

Separating the real and complex parts of (7.8) yields:

$$\begin{cases} r_T p_{ac} + x_T q_{ac} = e^2 - ev \cos \delta \\ j(r_T q_{ac} - x_T p_{ac}) = -jve \sin \delta \end{cases} \quad (7.9)$$

Disregarding the resistive term in (7.9), gives:

$$\begin{cases} p_{ac} = \frac{ev \sin \delta}{x_T} \\ q_{ac} = \frac{e(e - v \cos \delta)}{x_T} \end{cases} \quad (7.10)$$

Elevating both equations in (7.10) to the power of two and summing its terms, yields:

$$\sin^2 \delta + \cos^2 \delta = 1 = \left(\frac{x_T p_{ac}}{ev} \right)^2 + \left(\frac{x_T q_{ac} - e^2}{ev} \right)^2 \quad (7.11)$$

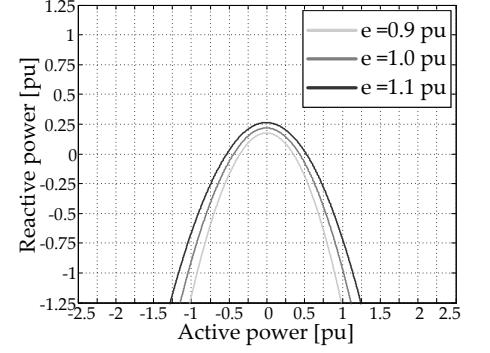
It is possible to rearrange (7.11) to represent the equation of a circle, $(p_{ac} - p_o)^2 + (q_{ac} - q_o)^2 = r^2$:

$$p_{ac}^2 + \left(q_{ac} - \frac{e^2}{x_c} \right)^2 = \left(\frac{ev}{x_c} \right)^2 \quad (7.12)$$

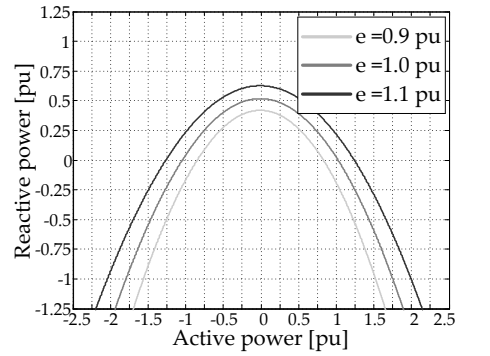
where;

$r = (ev/x_c)^2$ is radius of the circle [pu] and;

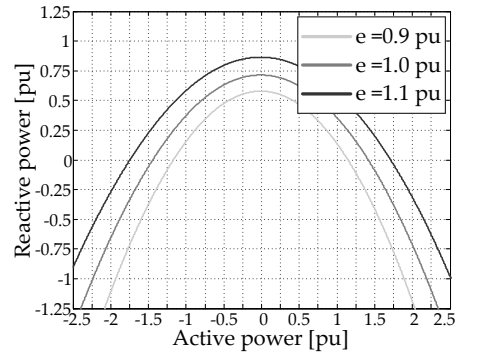
$(p_o; q_o) = (0; +e^2/x_c)$ are the circle centre coordinates [pu].



(a) SCR = 1



(b) SCR = 3



(c) SCR = 5

Figure 7.7: Critical frontier for the two-node network as a function of the ac network voltage for different SCR values between the nodes.

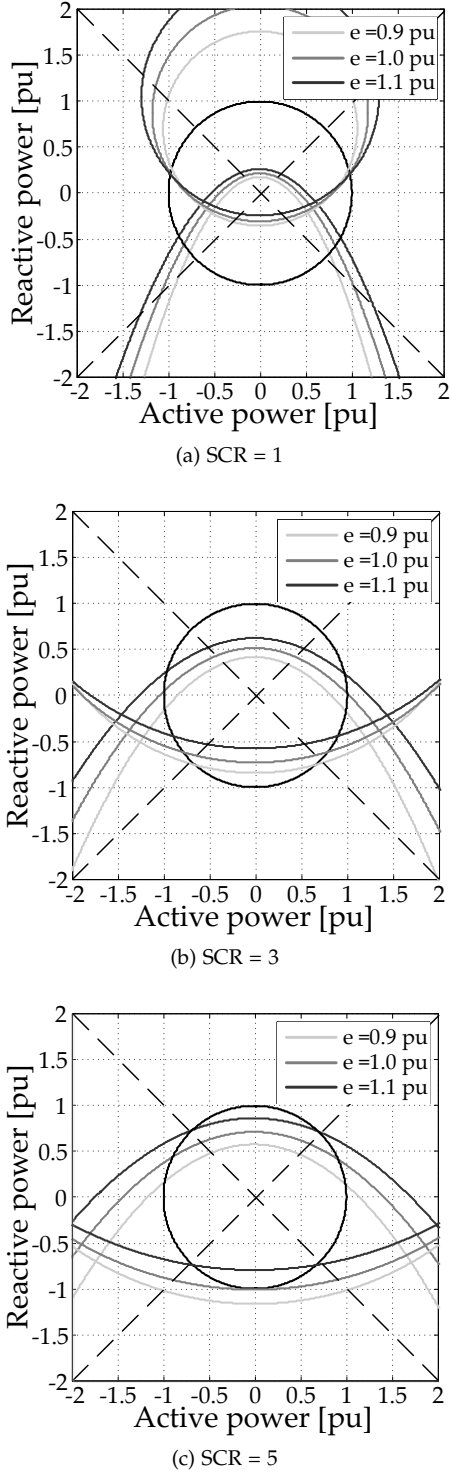


Figure 7.8: VSC-HVdc ideal capability chart superimposed with upper (critical frontier) and lower (max. direct voltage) reactive power limitations.

In this example, $V_b = 230$ kV and $V_{dc}^{max} = 1.10 \cdot (\pm 200$ kV). The dashed lines correspond to a power factor of 0.9.

The circle radius depends on the ac network voltage, and on the maximum converter voltage. Assuming the converter is using space-vector modulation, the maximum alternating voltage the converter can synthesise will be given by:

$$\hat{V}^{max} = \frac{2}{\sqrt{3}} \cdot \frac{V_{dc}^{max}}{2} \Rightarrow v^{max} = \frac{1}{\sqrt{2}} \frac{V_{dc}^{max}}{V_b} \quad (7.13)$$

where;

\hat{V}^{max} is the converter maximum single-phase peak voltage [V] and;
 V_{dc}^{max} is the maximum allowable direct voltage level [V].

Figure 7.8 shows the VSC-HVdc ideal capability chart with the critical frontier; the maximum direct voltage level restriction and power factor lines for $|\cos\phi| = 0.9$ superimposed.

To extend the range in which the converter injects reactive power into the network, i.e. $q_{ac} < 0$, a converter transformer can be used [188]. This can be used as an argument for having transformers in VSC-HVdc transmission systems [32]. However, the transformer increases the total series reactance between the VSC and the ac network.

Maximum Current Limitation

Hitherto, the analysis of the VSC-HVdc capability chart has only dealt with the converter active and reactive power. However, there is a very strict current limitation on VSC-HVdc systems. The converter valves, usually IGBTs, have very little, if any, overcurrent capacity. The VSC control system will make sure that the converter valves maximum current is not exceeded.

In a similar way to synchronous generators, it is possible to visualise the converter current as a function of the active power, power factor and available direct voltage, in a series of curves known as *v-curves*. Taking the phasor diagram from Figure 7.3 and rotating it, so that the ac network voltage is aligned with the abscissa, generates the phasor diagram shown in Figure 7.9.

Assuming the ac network voltage, e , is constant and aligned with the x-axis, it is possible to draw the geometric places of the converter current phasor tip $-\bar{i}$ (point p) – in such a way that the power transmitted to the ac network is constant (line P):

$$p_{ac} = e \cdot i \cos \phi = e \cdot i_x \Rightarrow i_x = \text{const} \quad (7.14)$$

where;

i_x is the active part of the ac network current [A].

In the phasor diagram shown in Figure 7.9, moving the point p over the line P , causes point r , i.e. the extreme of the converter voltage phasor, \bar{v} , to move over the vertical line R , which is xi_y distant from the x-axis.

the requirements presented in Section 7.1, when operating inside a MTdc network [188].

Frequency operating range

In the vector control strategy, the converter currents and voltages are transformed to the rotating (dq) coordinate system, which will be then synchronised with the ac network frequency through a phase-locked loop [46]. Therefore, even when inside MTdc networks, the VSC-HVdc station should not face any problems to remain connected to the ac network in case of frequency deviations from 0.93 to 1.07 pu, as shown in Figure 7.1.

Active Power Control

Usually, transmission system operators require that the active power and its rate of change are controlled in such a way that wind farms also participate in the primary and secondary frequency control [183]. These gradients, as given in (7.1) and (7.2), are usually in the seconds or even minutes range⁷.

Nevertheless, this requirement is also not particularly demanding for VSC-HVdc links. As shown in (4.18), a VSC operating at a switching frequency of 2 kHz can have a current control bandwidth up to 2.5 krad/s, which means it can vary its current output in the milliseconds range, and its power output within a few hundred milliseconds [112].

Reactive Power Control

In a similar way to the active power control, the converter can vary its reactive power output within a few hundred milliseconds. As discussed in Section 7.2, the reactive power output is limited both in the inductive and capacitive operation⁸. If the VSC-HVdc is connected to sufficiently strong ac networks, then this requirement should not be difficult to meet, as shown in Figure 7.8.

Reactive current supply during voltage dips

This particular requirement might complicate the operation of MTdc networks. The onshore converters have to supply reactive current during voltage dips as defined by the national grid codes (see Fig. 7.2 (b)) [182,183,185]. However, the onshore converters are also an active part of the MTdc grid operation and control.

Since the converter current capacity is limited, if 1 pu of reactive current is needed during voltage dips then the converter active current has to be zero (see Figure 7.2 (a)). If the converter cannot contribute with active current, it might become challenging to keep the dc network synchronised. This requirement will be specially problematic if it affects a VSC terminal responsible for controlling the MTdc network voltage, specially in cases where only one converter is controlling the dc grid voltage.

⁷ For instance, E.ON Netz requires that power be ramped up with a gradient higher than 0.10 pu/min and that curtailment is done with a minimum ramp down of 0.25 pu/s [184,186].

⁸ Nevertheless, most TSOs will usually require the VSC-HVdc stations to operate, in steady-state, with a power factor higher than 0.90, i.e. $0.90 \text{ ind} \leq \cos\phi \leq 0.90 \text{ cap}$ [186].

Fault ride through

In a MTdc network, after losing of a converter terminal, there might be a surplus or lack of active power. In case of power surplus, the direct voltage inside the MTdc network will start to rise; and, in case of lack of power, the direct voltage will start to collapse.

During the loss of a terminal, to successfully ride through the fault, the active power balance inside the MTdc network needs to be promptly reestablished. For MTdc networks integrating offshore wind farms, there are several possible actions which can be taken to assure a successful ride through, e.g. fast power reduction methods, install dc choppers on the VSC stations, and apply different MTdc control strategies such as the distributed voltage control strategy [163,193,194].

7.4 AC-side Contingencies

The objective of this section is to study whether a VSC-HVdc can comply with the grid code requirements when inside a MTdc network, and what are the effects of these requirements on the network operation and control [188]. The system under consideration is presented in Figure 7.11, and is composed of two ac networks and two offshore wind farms, whose parameters are given in Table 7.1.

The case study consists in analysing the effects; on the MTdc network, of a voltage dip in ac grid 2, for two different scenarios. The

Table 7.1: MTdc network rated parameters used in the grid code requirement case study.

	Parameter		Unit	Value
AC Grid 1	Short-circuit Power	S_{k1}	MVA	9500
	Rated Voltage	E_{L1}	kV	380
	Voltage Ratio	N	kV/kV	380/300
AC1 Transformer	Rated Power	S_{t1}	MVA	1200
	Impedance	Z_{t1}	pu	0.005+j0.100
AC Grid 2	Short-circuit Power	S_{k2}	MVA	4400
	Rated Voltage	E_{L2}	kV	300
OWF 1 & 2	Installed Capacity	P_{ac}^{owf}	MW	1000
	Collection voltage	V_{owf}	kV	33
	Voltage Ratio	α	kV/kV	33/275
OWF Transformer	Rated Power	S_{t1}	MVA	1100
	Impedance	z_{t1}	pu	0.005+j0.100
	Rated Power	S_{vsc}	MVA	1200
VSC-HVdc	Rated alternating voltage	V_c	kV	300
	Phase Reactor	z_c	pu	0.003+j0.150
	Rated direct voltage	V_{dc}	kV	± 320
	DC Sice Capacitance	C_{dc}	μF	75
	Rated direct voltage	V_{dc}	kV	± 320
MTdc Network	DC cable impedance	z_{dc}	Ω/km	0.02+j0.06
	DC cable capacitance	l_{dc}	nF/km	220

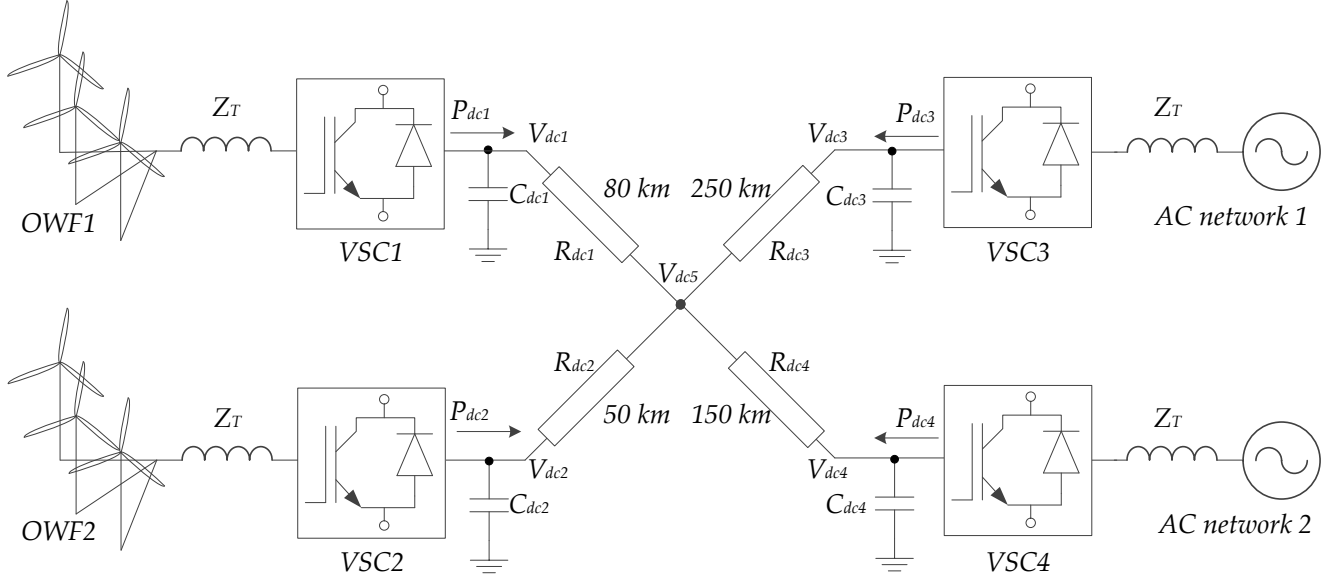


Figure 7.11: 4-node parallel VSC-MTdc network under study.

scenarios are based on two grid code requirements, low and high, characterised as follows (see Table 7.2):

Table 7.2: Scenarios description for the grid code requirement case study.

Scenario	i	ii
P_{OWF1} [pu]	0.6	0.7
P_{OWF2} [pu]	0.6	0.7
GCR	low	high

$$\begin{cases} \text{low GCR: } i_d = 1 \cdot (|e_2| - 1), \forall |e_2| \geq 0.1 \\ \text{high GCR: } i_d = 2 \cdot (|e_2| - 1), \forall |e_2| \geq 0.1 \end{cases} \quad (7.16)$$

where;

i_d is the VSC reactive current [A] and;

$|e_2|$ is the amplitude of the ac grid 2 voltage [V].

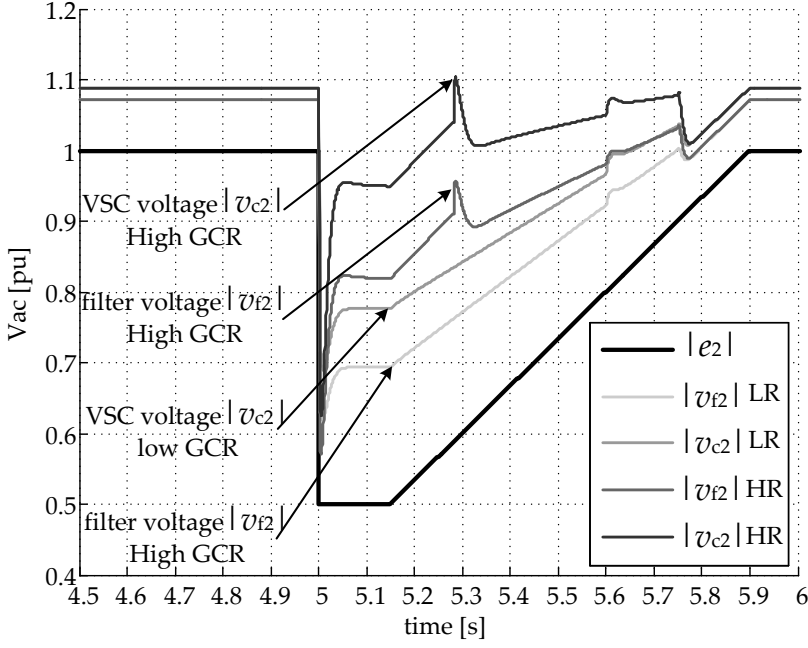
In both scenarios, VSC1 controls the MTdc network voltage at 1 pu, whereas VSC2 operates as an inverter with 0.6 pu power. The OWFs generation shown in Table 7.2, is ramped up with a gradient of 1 pu/s⁹.

The ac grid 2 voltage dips at $t = 5.0$ s, for 150 ms, and is linearly restored to 1 pu after 750 ms. According to Table 7.2, during the voltage dip, the converter reactive current, i_d , is 0.5 pu for the low GCR (scenario i), and 1.0 pu for the high GCR (scenario ii).

Figure 7.12 shows the converter and the ac filter voltage resulting from the dynamic simulation model. As expected, the voltage recovery is better when more reactive current is injected. However, the grid code requirement impact on the MTdc network can be substantial. The active powers and direct voltages at the four VSC-HVdc terminals are presented in Figure 7.13 and Figure 7.14, respectively.

During the fault, the VSC1 terminal cannot control the MTdc network voltage. The total power generated offshore is 1.3 pu and the dc network voltage rises due to the excess power. The different reactive current requirements have a substantial impact on the MTdc network during the fault. If, during the dip, the VSC2 terminal only needs to supply 0.5 pu of reactive current (scenario i) it still has space left for active current. Therefore, with a lower GCR, the MTdc network volt-

⁹ The OWF generation is given in per unit of the VSC-HVdc station base power (1200 MVA). The VSC-HVdc controllers are arranged so that the offshore VSC terminals are set to control the alternating voltage and frequency of the wind farms to fixed values; the onshore VSC terminal 1 is set to control the its reactive power and the voltage of the MTdc network, whereas the VSC 2 is set to control the active and reactive power exchanged with ac grid 2.



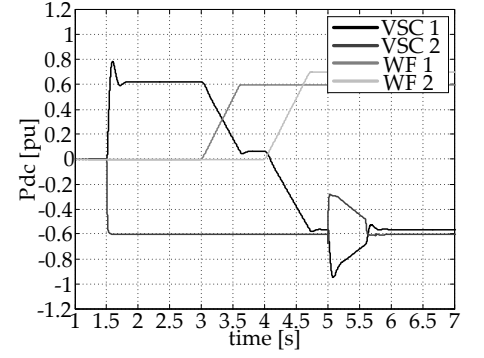
age stays controlled. Indeed, in scenario i, the direct voltage transient has a peak of a little over 1.05 pu.

Meanwhile, in scenario ii, until the ac fault is not cleared, the direct voltage keeps linearly increasing. In that case, the direct voltage transient has a peak of almost 1.20 pu, even though the power surplus in the MTdc network was only circa 0.3 pu.

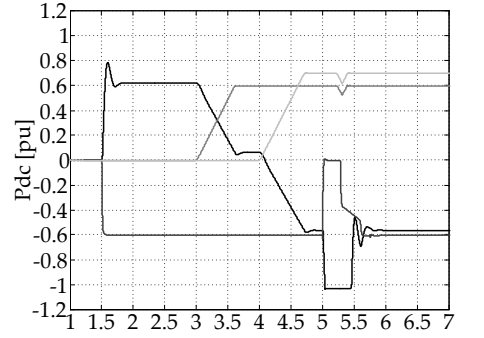
In scenario ii, when the direct voltage becomes higher than 1.10 pu, circa 50 ms after the fault, the VSC-HVdc terminals at the offshore wind farms start to curtail power to try and reestablish the synchronism in the MTdc network.

It is worthwhile noting that during the fault, the remaining terminals have no other way of knowing about the contingency than through the MTdc network voltage level [188]. If wind curtailment

Figure 7.12: AC grid 2 voltage profile during the dip. The graphic shows the voltage module at the converter terminals, ($|v_{c2}|$), and at the ac filter capacitance, ($|v_{f2}|$), for the low and high GCR.

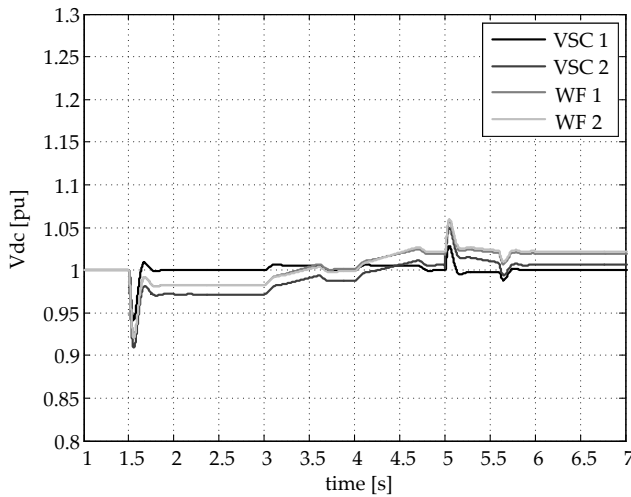


(a) Scenario i

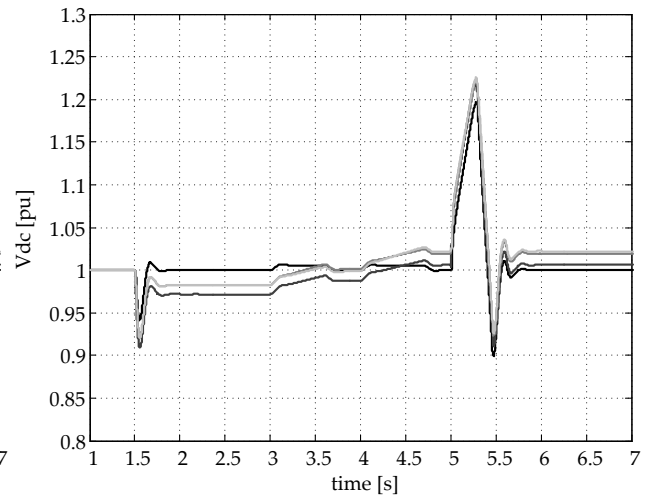


(b) Scenario ii

Figure 7.13: Active power of all converters during the dynamic simulation.



(a) Scenario i



(b) Scenario ii

Figure 7.14: Direct voltage of all converters during the dynamic simulation.

will not suffice, the direct voltage will continue to rise until it reaches unacceptably high values, which could damage the converters and cables in the MTdc network. In that case, other protective measurements, such as dc choppers with braking resistors are needed [193,194].

Conclusion on AC Contingencies

In conclusion, the development of offshore MTdc networks will depend on whether the system can be reliably controlled, and safely operated under normal and contingency situations. The grid code requirements, specially reactive current supply during voltage dips, can substantially impact the MTdc network operation.

As offshore wind farms tend to be connected to ac grids on peripheral locations, the grid code requirements true efficacy needs to be evaluated. Unfortunately up to now in Europe, a synchronised approach towards grid code requirements has not yet been taken. However, if they can be alleviated, it will be easier to control MTdc networks.

7.5 DC-side Contingencies

The behaviour of MTdc networks during contingencies will be vital for its successful development. The previous section has analysed the effect of grid code requirements on the dynamic response of MTdc networks during ac contingencies. Although demanding, provided with the correct controls and more friendly grid codes, VSC-HVdc stations, and MTdc networks, should be able to ride through ac faults. On the other hand, after a dc contingency the system will most likely have only a few milliseconds to clear the fault before high dc currents start posing a threat to the entire MTdc network [33].

Therefore, several efforts have concentrated on research and development of HVdc switch breakers [34,195]. Previous research on protection of high-voltage MTdc networks have also focused on: how dc fault develops [196–198]; dc fault detection methods [199,200]; and protection systems [201–203].

The main contribution of this section is the comparison of different HVdc transmission system configurations under dc fault cases, and the analysis of the impact of different dc limiting reactors and dc switch breaker technologies on the dc fault currents [204]. The most common configurations of HVdc transmission system were introduced in Chapter 2 (Section 2.4). The available dc breaker technologies for protection of multi-terminal dc networks are discussed next in Section 7.6. A methodology is then presented to select a dc breaker technology, and establish whether dc protection reactors are necessary. Afterwards, through a dynamic simulation model, a case study is carried out for comparing the performance of the different HVdc system configurations. Finally, in accordance with the obtained results, conclusions and recommendations are drawn.

7.6 DC Breaker Technologies

Independently from the converter technology, there are two main configurations for HVdc transmission systems: monopolar and bipolar [37]. Table 7.3 displays the analysed configurations; all of which can be employed to form MTdc networks [37,40]. Figure 7.15 depicts a single-phase representation of a HVdc converter station connected to three-phase ac systems via a transformer. The converter configuration is abstracted as the main HVdc transmission system configurations are distinguished by their dc circuit schemes.

Although LCC-HVdc remains the most common and mature HVdc technology, its inherent low controllability, as well as difficulties in forming MTdc networks using this technology, have driven industry and researchers towards the application of voltage-source converters for transmission purposes.

In a VSC-HVdc system, which uses controllable power electronic switches, power flow reversal only involves changing the converter current direction while the direct voltage remains constant, making it easier to develop high-voltage MTdc networks. However, the use of IGBT valves in the converters is, at the same time, a main drawback. Contrary to thyristor valves, in case of a dc fault, IGBT valves cannot block the fault current – due to the anti-parallel diodes – which makes voltage-source converters prone to damage. This issue becomes more challenging in case of a multi-terminal network where several converters feed the fault.

As a result, dc breakers are required to isolate the fault and resume normal operation without interruptions. Hence, protecting MTdc networks has led to the development of a variety of dc breaker models. Next, an overview of the most common dc breaker technologies is provided.

Passive Resonance Breakers

Resonance breakers composed of three current paths – as the one shown in Figure 7.16 – are based on ac GIS breakers. During normal operation, the current flows through a low-loss switch, which opens as soon as a fault is detected, creating an arc. As the arcing voltage is high, an RLC path is needed to limit the commutation voltage.

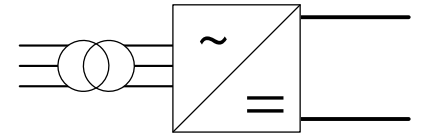
The energy storage elements create a resonant current through the main path switch, which can interrupt the current when it crosses zero. The surge arrestors limit the maximum voltage across the resonant circuit capacitor, and the current is commutated to the energy absorbers which bring it down to zero [195,205,206].

For passive resonance breakers, the maximum interruptible current depends on the arc voltage-current characteristic. If the current surpasses the instability limit, i.e. $|di/dt| \geq 0$, it will not have zero crossings [206,207]. In this case, a zero crossing has to be excited through an external circuitry [195].

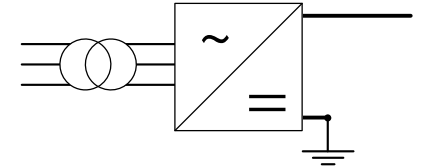
The main advantages of this breaker technology are its low cost,

Table 7.3: Description of the HVdc transmission configurations analysed in the dc fault case study.

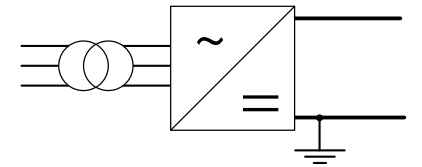
	Configuration	
	A. Monopolar	B. Bipolar
Return Path	(a) Symmetric (b) Ground (c) Metallic	(d) Ground (e) Metallic



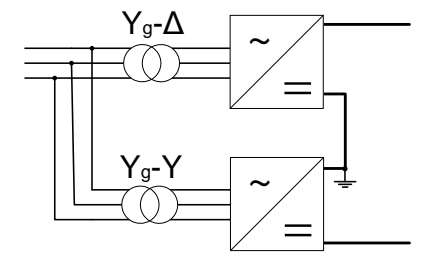
(a) Symmetric monopole



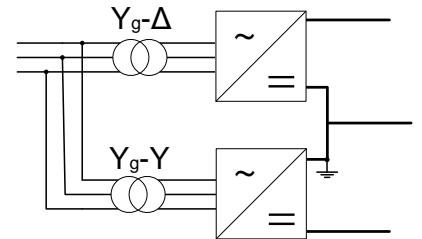
(b) Asymmetric monopole with ground return



(c) Asymmetric monopole with metallic return



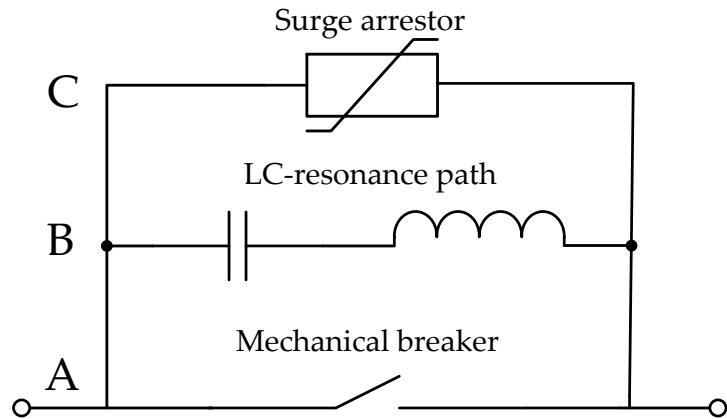
(d) Bipolar with ground return



(e) Bipolar with metallic return

Figure 7.15: HVdc transmission configurations analysed in the dc fault case study.

Figure 7.16: Resonant dc breaker circuit [205, 208].



and its low on-state losses. However, they are significantly slower than the other investigated technologies [206,208].

Hybrid Fault-Current Limiting Breaker (Hybrid II)

Hybrid breakers combine the use of fast semiconductor switches with current-limiters, or mechanical switches, and usually consist of three paths in parallel (see Figure 7.17) [209].

The first path, consisted either of a mechanical breaker or of an ultra-fast switch (UFS), commutates the current to the second path. The second path includes GTOs, and a diode bridge to accommodate bidirectional fault currents. As soon as the current crosses zero on the second path, a fast disconnecting switch is opened to isolate it. Finally, the current is commutated to the third path, which acts as a current limiter [209]. This path has a high positive temperature coefficient (PTC) resistor and a load switch, which can interrupt the current at the first zero crossing.

To meet the voltage-withstand requirements, a mechanical switch is inserted in series to the dc breaker, resulting though in increased interruption times ($\approx 20\text{ms}$) [206,210].

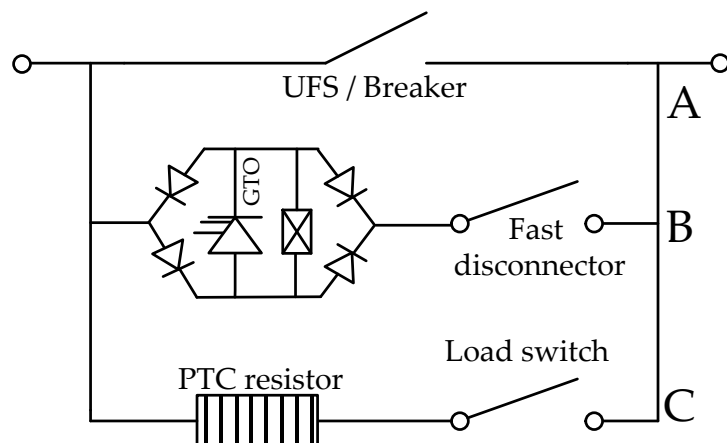


Figure 7.17: Hybrid II dc breaker circuit [210].

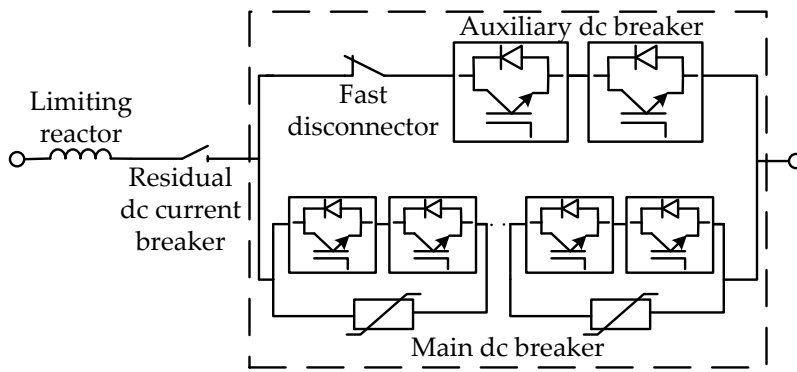


Figure 7.18: Hybrid I dc breaker circuit [34].

Hybrid Solid State Breakers (Hybrid I)

This dc breaker, shown in Figure 7.18, aims at a compromise between switching speed and on-state losses. It uses two current paths: one for conduction, and one for interruption (main breaker path)¹⁰.

Because of the mechanical disconnector, the interruption time is higher than for full solid-state breakers (presented next). Nevertheless, opening times of 2 ms are possible if several mechanical switches are connected in series, as in the modular hybrid IGBT dc breaker proposed by ABB [34]. The hybrid breaker has also two main paths: a conduction path with one fast mechanical disconnector and a small number of semiconductor switches in series; and the main breaker path, rated for full current and voltage breaking capability.

¹⁰ When a fault occurs, the auxiliary dc breaker commutates the current to the main breaker path and a fast mechanical disconnector opens. Since the auxiliary breaker only needs to commutate the current to the main breaker path, it can have lower voltage and current ratings so that its on-state losses are minimised during normal operation.

Solid State Breakers

In solid-state breakers, a large number of semiconductor switches are connected in parallel, and in series, to withstand the maximum breaking current and voltage. Several topologies using solid-state switches have been proposed, but generally the breaker consists of three paths, as the one shown in Figure 7.19 [206,209,211].

There are two conduction paths for bidirectional power flow, in

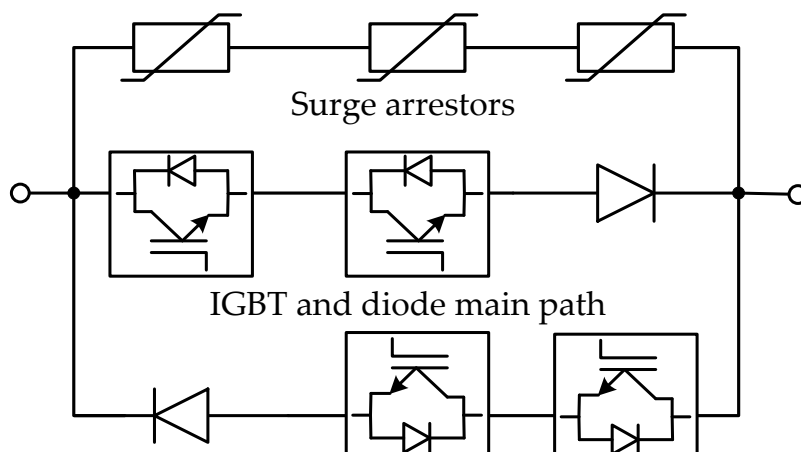


Figure 7.19: Solid-state dc breaker circuit [195].

	Solid State	Hybrid I	Hybrid II	Passive Resonance
Commutation [ms]	switch: 0.1	switch: ≤ 0.2 ; breaker: ≈ 0.25	switch: ≈ 0.1 ; breaker: ≤ 20 ; UFS: 1-5	breaker: ≤ 20 ; resonance: ≈ 30
Energy absorption [ms]	≈ 1	≈ 1	-	-
Interruption time (t_b) [ms]	≈ 1	≈ 2	≈ 30	≈ 60
Max. voltage [kV]	≤ 800	tested: 120; expected: 320	AC-CB: ≥ 500 ; UFS: ≤ 12	available: ≤ 550
Max. current [kA]	≤ 5	tested: 9; expected: 16	estimated: 6 - 12	tested: 4
Losses [% converter rating]	IGCT $\approx 30\%$ GTO $\approx 40\%$	$\leq 1\%$	negligible	negligible

Table 7.4: DC breaker technologies comparison

which the number of switches depends on the breaker voltage rating. A diode is used to prevent currents to flow through the switches anti-parallel diodes when these are blocked. As soon as a fault is detected, the switches get blocked, and the current commutates to the parallel connected varistors in the other path. The voltage and current across the main interruption path are then suppressed by the surge arrestors [211].

As switching speed is essential for MTdc networks, IGBTs and IGCTs¹¹ are currently the preferred choice in solid-state breakers, and the total interruption time is kept around 1 ms [206,209]. However, the use of semiconductors in series introduces significant on-state losses [209]. Hitherto, solid-state breakers have only been tested low in LVdc and in MVdc grids [206,209,212].

Table 7.4 gives a summary of the most important parameters for the dc breakers technologies presented.

7.7 Protection of MTdc Networks

The aim of this section is to compare the different HVdc configurations for the development of MTdc networks, and to provide a methodology for selecting protection measures against dc faults. The layout of the MTdc network used is shown in Figure 7.20.

A four-terminal grid with a radial configuration was selected since, most likely, early MTdc networks will have a limited number of terminals. Moreover, in case of a dc fault, a radial network can be considered more challenging than a meshed one since a converter has to be isolated from the network. The main MTdc network parameters used in the simulation are shown in Table 7.5.

To analyse the dc fault behaviour of the MTdc network shown in

¹¹ Integrated gate-commutated thyristors.

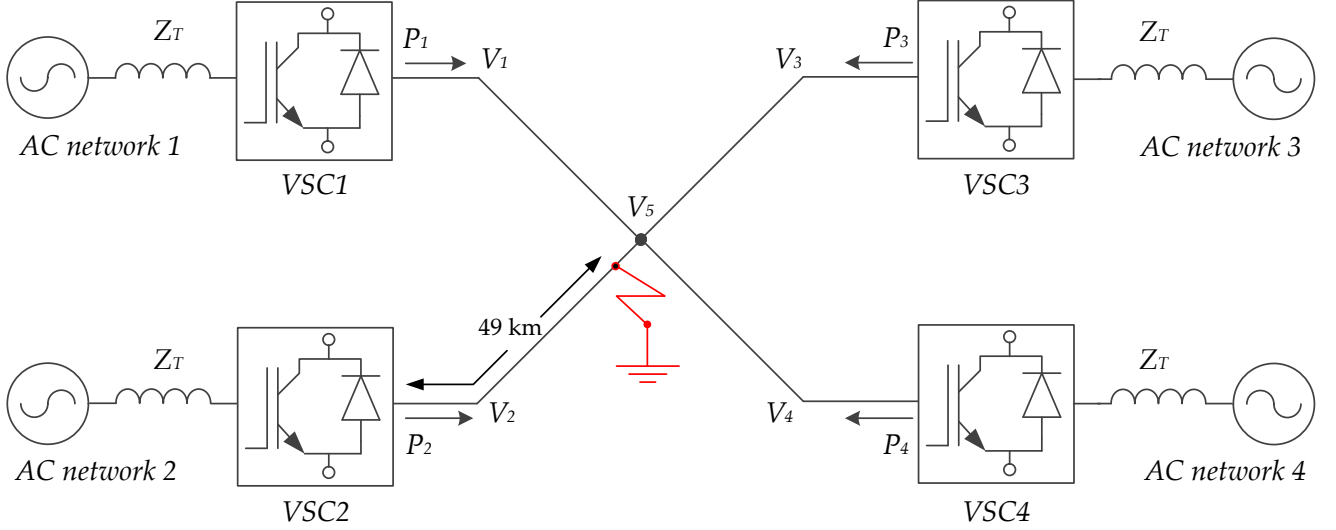


Figure 7.20: Layout of the analysed radial MTdc network with 4 terminals.

Figure 7.20, a dynamic simulation model was developed using the SimPowerSystem toolbox of Matlab/Simulink. Since it is difficult to analyse the VSC response to a dc fault using an averaged model, all simulations were performed using a model which includes the converter switching behaviour [204].

Methodology

The work flow of the proposed methodology is presented in Figure 7.21 [204]. Each step of the methodology is explained next.

1. Select HVdc configuration

The starting point is the selection of a configuration for the MTdc network. In this work all configurations shown in Table 7.3, and displayed in Figure 7.15, are compared through means of a dynamic simulation model.

2. Select dc fault type

Once the dynamic simulation model is built, a dc fault type and location needs to be selected. There are two main types of dc faults which can occur in a MTdc grid: pole-to-ground fault and line-to-line fault, or short-circuit fault. If underground or submarine cables are used, line-to-line faults are very rare when compared to pole-to-

Table 7.5: MTdc network parameters

DC grid parameters	Value
VSC rated power (S_{VSC})	1200 MVA
MTdc voltage (V_{dc})	± 320 kV
Rated current (I_{dc})	2.062 kA
Cable Resistance (R)	$0.0195 \Omega/\text{km}$
Cable Inductance (L)	$0.2 \text{ mH}/\text{km}$
Cable Capacitance (C)	$220 \text{ nF}/\text{km}$
Cable size (d)	50 km
AC Network HV side (E_h)	380 kV
AC Network LV side (E_l)	150 kV
Transformer rated power (S_T)	1200 MVA
Transformer impedance (Z_T)	$0.1 + j0.001 \text{ pu}$

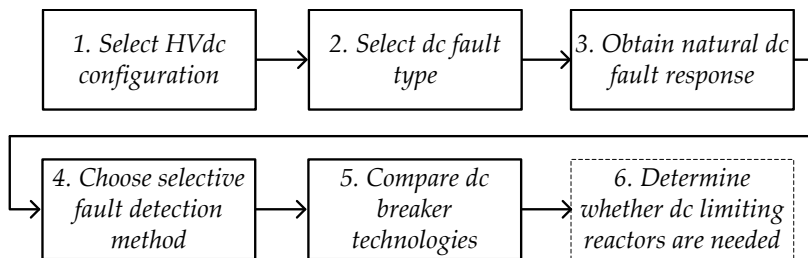


Figure 7.21: Workflow of the methodology used in the configurations study

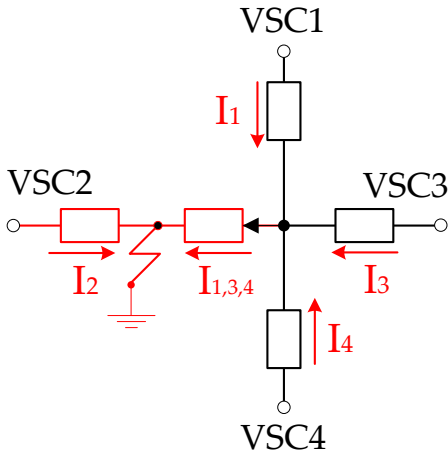


Figure 7.22: Current direction in case of a fault in the dc line of VSC2.

ground faults, hence the latter was selected [213]. All pole-to-ground faults were simulated with a ground resistance of $7\ \Omega$, corresponding to wet loamy sand ground type [214].

Additionally to selecting the fault type, the fault location also needs to be determined. Three different fault locations – 1 km, 25 km and 49 km (measured from VSC2) – were analysed. The results have shown that as the fault moves closer to the middle point of the MTdc network, the peak current is higher and it takes less time to reach it. Figure 7.22 shows the current directions in the MTdc network in case of a fault on the dc line leading to VSC2.

3. Obtain natural dc fault response

Generally, dc faults develop in three stages. In the first stage, the VSC capacitors and the line energy storage elements get discharged through the fault. Then, the converter switches get blocked for their protection, and the VSC acts as a diode bridge rectifier. Finally, after the transients from the system forced response die out, the MTdc network currents reach a new steady state. Figure 7.23 shows the theoretical and the simulated fault current response of a VSC in case of pole-to-ground fault.

4. Choose selective fault detection method

In addition to the overcurrent protection implemented in the VSC-HVdc terminals, to protect the converter valves a selective fault detection method has to be determined to distinguish the faulty line from the other lines in the network.

The main objective of a fault detection scheme is to reliably detect the fault as fast as possible. As soon as a fault is detected, signals

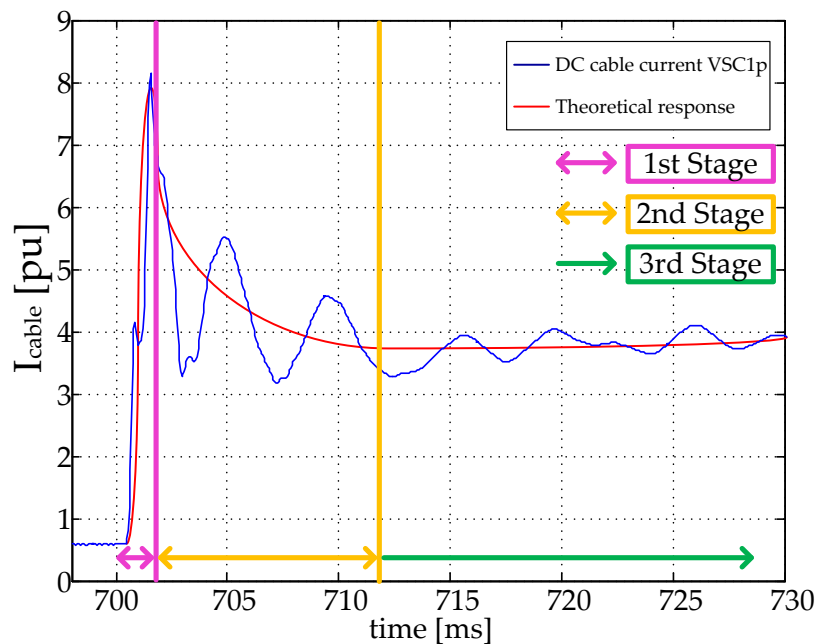


Figure 7.23: Theoretical and simulated fault current response of a VSC in case of pole-to-ground fault.

are transmitted to block the converter valve, safeguarding their operation, and to the dc breakers controller so the faulty line can be isolated.

Two methods were compared to detect a fault: the current direction method and the current derivative method. In this thesis, the current direction method was selected since the difference in the VSC terminals current derivatives during the fault were less than 5%, which makes it difficult to implement the current derivative method in practice.

The current direction method work as follows: whenever the currents at the terminals of a line have opposite directions, a fault signal is generated blocking the converters and triggering the concerned dc breakers (see Figure 7.22). To avoid any false signal resulting from oscillations in the MTdc grid, a current threshold of 2 pu was used.

5. Compare dc breaker technologies

The dc breaker was modelled as an ideal switch with a time delay. The model is shown in Figure 7.24 and the time delays – interruption time (t_b) – used for the different simulated dc breakers are summarised in Table 7.4.

The breaker technology was assumed to not influence the MTdc network dynamic response as, under normal operation, it does not change the characteristics of the dc lines. Moreover, all breakers models were included in the simulations albeit the hybrid solid-state breaker with mechanical disconnecter (Hybrid I) and the resonance breaker are, hitherto, only available for voltages lower than those simulated (± 320 kV).

6. Define whether dc limiting reactors are needed

The total time necessary to realise and isolate a fault, t_{fault} , before any converter station gets affected depends on three basic factors: the time it takes for the selective fault detection method to signal the fault, t_d , the dc breaker interruption time, t_b (given in Table 7.4), and the line transport delay, t_l , i.e.:

$$t_{fault} = t_d + t_b + t_l \quad (7.17)$$

On the other hand, the time it takes for the overcurrent protection of a VSC to be triggered, t_{vsc} , is given as:

$$t_{vsc} = t_l + t_{ctr} + t_{(I_0 \rightarrow 2pu)} \quad (7.18)$$

where;

t_l is the line transport delay from the fault point [s];

t_{ctr} is the converters protection controller delay [s] and;

$t_{(I_0 \rightarrow 2pu)}$ is the time the converter current needs to surpass the overcurrent threshold value [s].

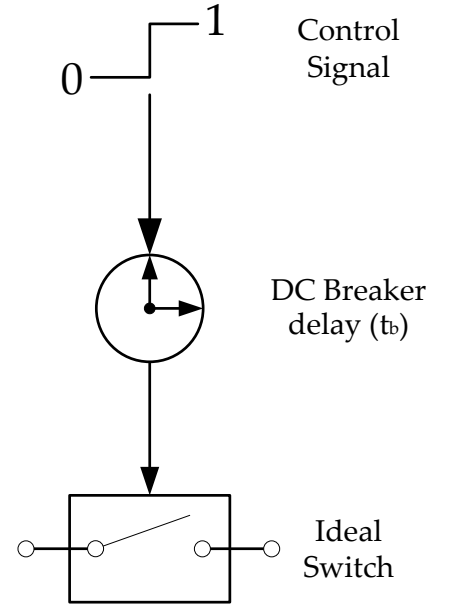


Figure 7.24: DC breaker model

Finally, the line transport delay, t_l , is calculated as:

$$t_l = \frac{d}{v} = d\sqrt{lc} \quad (7.19)$$

where;

d is the line length [m] and;

l is the line per unit-length inductance [H/m] and;

c is the line per unit-length capacitance [F/m]¹².

¹² When calculating the transport delay, the dc limiting reactor inductance also needs to be taken into consideration.

To ensure the system protection, and its normal operation, can resume at the post-fault state, without affecting the MTdc network operation, the time in which the VSC-HVdc terminals experience overcurrents has to be higher than the total fault detection and interruption time, or:

$$t_{fault} < t_{vsc} \quad (7.20)$$

Therefore, increasing the dc limiting reactor size has two main beneficial effects: it delays the overcurrent protection triggering and reduces the fault current peak value. However, the sizing of the dc limiting reactor will be given as a compromise between dc fault current requirements, volume and costs¹³.

¹³ For air-core reactors, the cost, Co , and mass, M , relationship with the reactor rated current, I_n , and inductance, L , was given in (4.6):

$$Co, M \propto I_n \sqrt{L}.$$

Based on the dc limiting reactor value, new natural fault current responses can be obtained. Therefore, it is possible to compare the new peak current values, and the time they occur, with the MTdc network response without any reactors. If the value of the peak current is higher than the rated current of the dc breaker, then another breaker technology must be chosen or the dc limiting reactor must be increased. Analogously, if $t_{vsc} < t_{fault}$, a higher value of dc limiting reactor must be selected.

Results

As pole-to-ground faults are being investigated, results from the dynamic simulations have shown that in the bipolar configuration the dc fault did not influence the negative pole converters. Before, during, and after the fault, the negative pole converters kept operating independently from the positive pole converters. The same analysis has shown that the fault response of an asymmetric monopolar with ground return can safely be assumed analogous to that of the bipolar configuration with ground return.

The same reasoning applies to the asymmetric monopolar with metallic return configuration, in which the fault response is equivalent to that of the bipolar configuration with metallic return. The only difference between the bipolar and the asymmetric monopolar configurations, is the inability of the latter to continue normal operation during the pole-to-ground fault [204].

Hence, the results are presented for the symmetric monopolar configuration (configuration (a) in Figure 7.15), the ground return configurations (configurations (b) and (d)) and the metallic return configurations (configurations (c) and (e)).

In all simulations, the current through the converters, dc capacitors, dc lines, and at the fault point were monitored. The simulation was performed for 1 second, and the fault was applied on MTdc line 2, 49 km away from VSC2, at $t = 700$ ms. The MTdc network voltage was controlled by VSC1 terminal, whereas all other terminals operated in current regulation mode controlling their active power. The order of events in the MTdc network is presented in Table 7.6. It is important to note that the VSC terminals power references were not changed before and after the fault.

Natural DC Fault Responses

After applying the dc fault in the dynamic model, the next step in the methodology is to obtain the natural dc fault response for the different HVdc configurations (see Figure 7.21).

Figure 7.25 displays, for the symmetric configuration, the total fault current, and the contributions from the different MTdc network components, in case no action is taken to interrupt the fault¹⁴.

From all investigated configurations, the symmetric monopole appears to have the best response to pole-to-ground faults. During the simulation, only VSC1 – which is responsible for controlling the MTdc network voltage level – experienced overcurrents. Additionally, as soon as the dc lines and dc capacitors get discharged, the fault current decays to zero in the steady-state phase, approximately 25 to 30 ms after the fault occurrence.

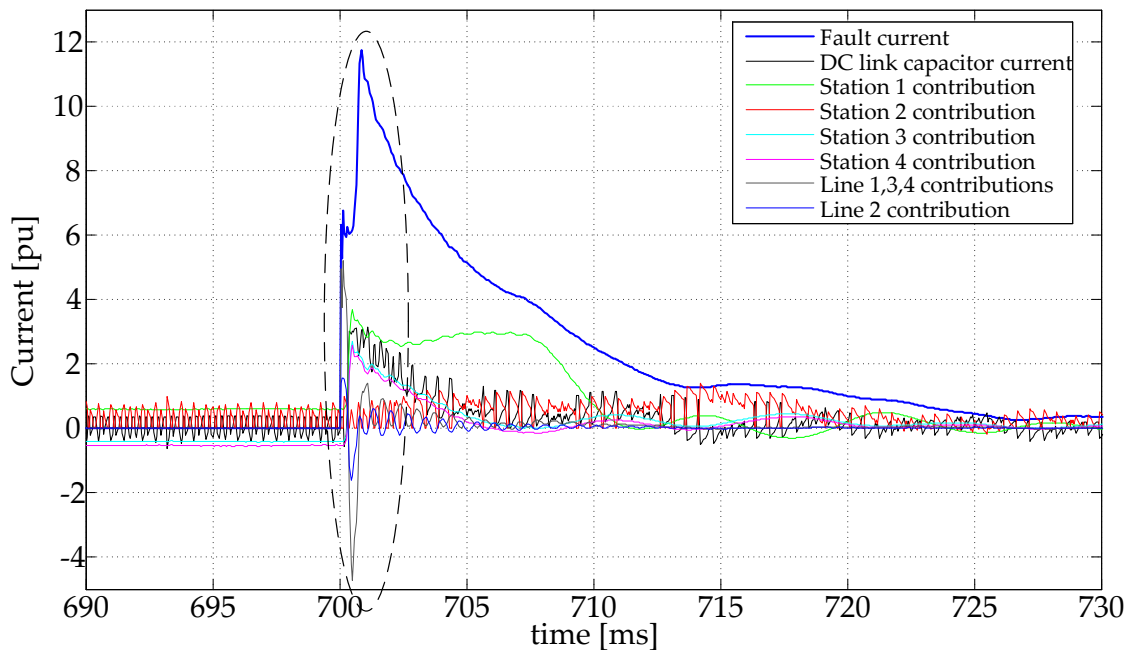
Figure 7.26 displays, for the ground and metallic return configurations, the total fault current response, and the contributions from the different MTdc network components, in case no action is taken to interrupt the fault.

Table 7.6: VSC active power during the simulation of the line-to-ground fault.

Time [s]	0.5	0.7
P_{VSC2} [pu]	-0.3	fault
P_{VSC3} [pu]	0.3	0.3
P_{VSC4} [pu]	0.4	0.4

¹⁴ As previously discussed, the fault currents develop in three phases: two transient phases, and one steady-state phase. The initial peak of the fault current, marked with an ellipse, shows that the transient period lasts for circa 15 to 20 ms.

Figure 7.25: Current response to a pole-to-ground on MTdc line 2 for the symmetric monopole configuration.

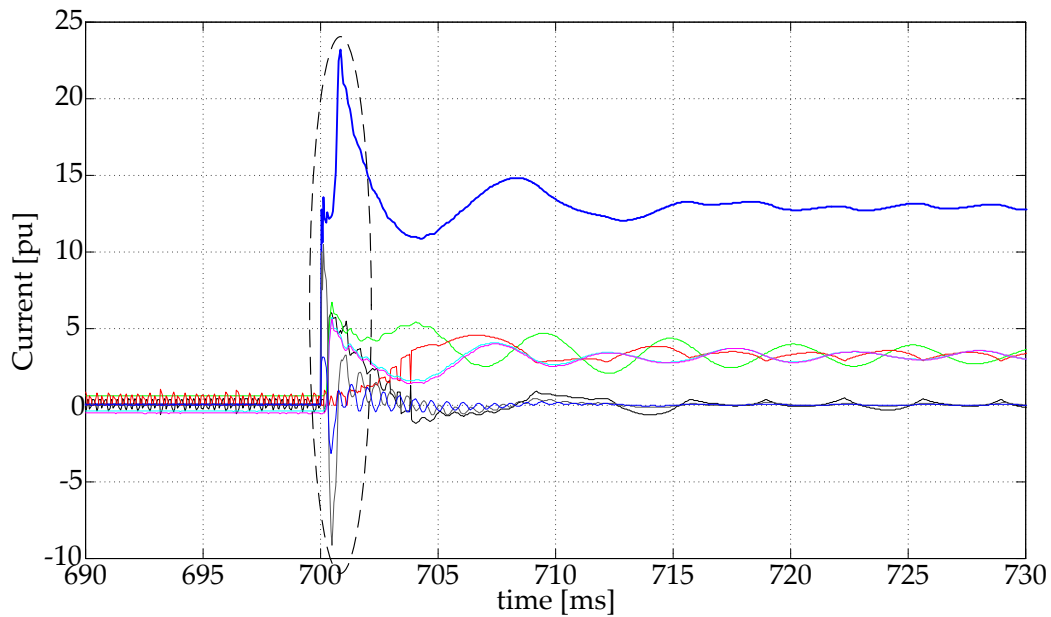


(a) Symmetric monopole

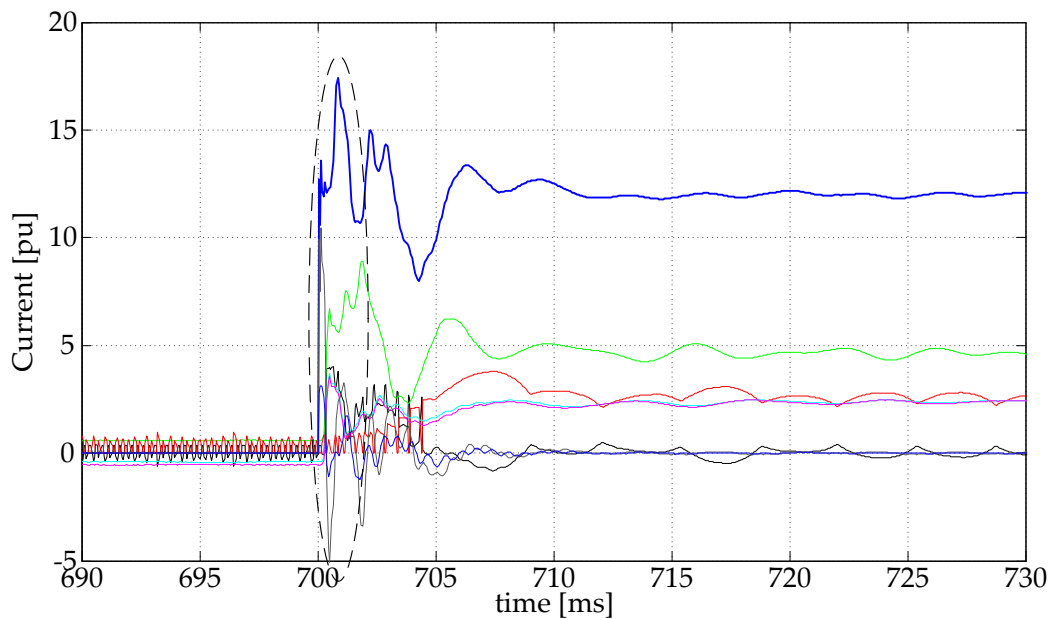
The bipolar and the asymmetric monopolar configurations with ground return have the worst performance in comparison with the other configurations. The fault current contributions from the converters are higher, as there is no return path impedance, and the fault affects the converters faster, i.e. high overcurrents occurred within less than 0.4 ms, up to 2 ms faster than in the case of metallic return configurations. Additionally, the converters currents in the steady-state phase were higher, namely 4 pu, which can produce damage.

In the configurations with metallic return, the fault current peak reached 18 pu during the transient period. The grounding point of the metallic conductor was identified as a crucial issue as it significantly influences the current contributions to the dc fault during

Figure 7.26: Current response to a pole-to-ground on MTdc line 2 for the ground and metallic return configurations.



(a) Ground Return: Bipolar and Asymmetric Monopolar



(b) Metallic Return: Bipolar and Asymmetric Monopolar

steady-state. It also affects the time required for each VSC to experience an overcurrent, which needs to be considered when designing selective fault detection methods.

In all configurations, as the fault point is close to the middle node of the MTdc network, the fault current is initially fed only from the discharging of the dc lines. After circa 1.0 ms, namely the line travelling time, the VSC terminals start feeding the fault and VSC2 is, as expected, the terminal that contributes the most.

Peak current

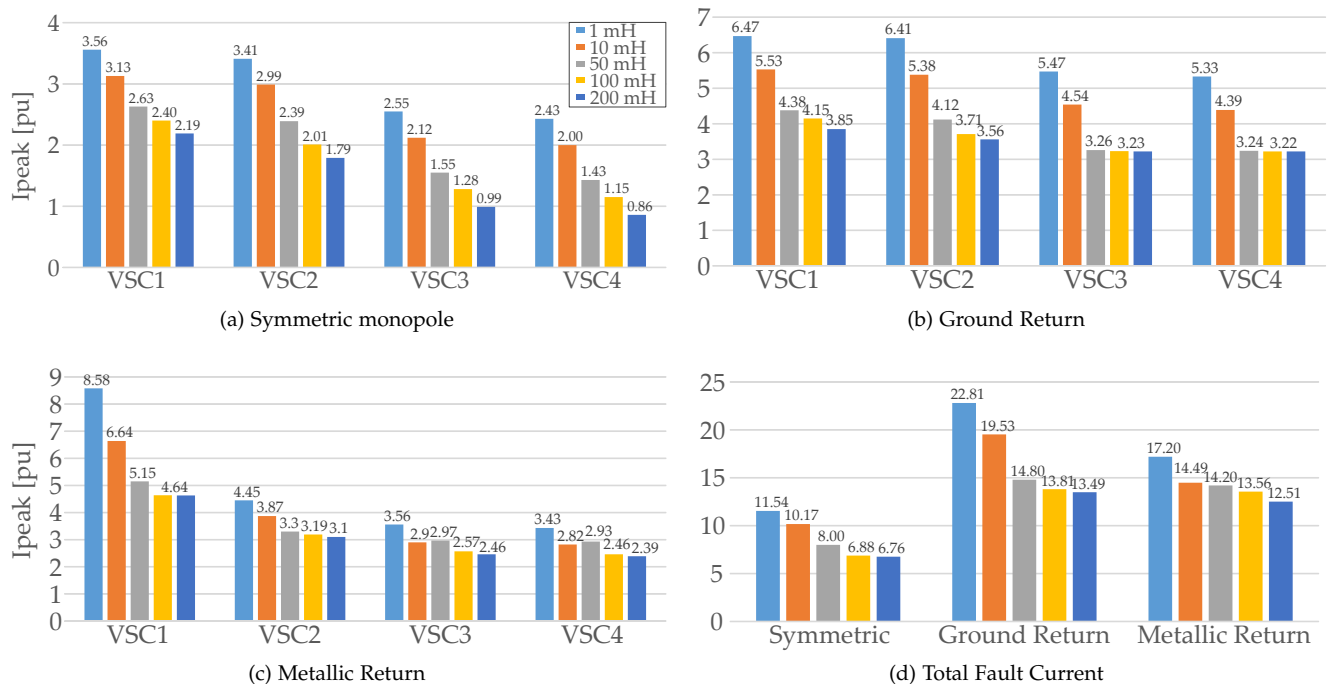
Analysing the graphics in Figure 7.25 it is evident that the converters have a very limited time to react to the fault currents, and that the currents peaks are excessive. Hence, dc limiting reactors are needed to increase the time before the converters go into overcurrent protection, and to lower the fault current peaks. The values of the fault current peak for each VSC-HVdc terminal cable, i.e. after the converter output capacitor, are shown in Figure 7.27.

The symmetric monopole configuration displays the smallest overcurrents once dc limiting reactors are installed. Moreover, only VSC1 suffers with overcurrents higher than 2 pu in its ac side if dc limiting reactors of less than 10 mH are used. All other VSC-HVdc terminals do not experience overcurrents in their ac sides¹⁵.

Between the ground and metallic return configurations, the configurations using metallic return have the advantage of the additional cable impedance, which further limits the fault currents. Thus, regarding the value of the peak current, it is more advantageous to build the MTdc network using a metallic return.

¹⁵ Figure 7.27 displays the peak currents on the dc side of the VSC-HVdc stations, which is why some of the values shown are higher than 2 pu while the overcurrents in the ac side are still lower than 2 pu.

Figure 7.27: Peak dc fault currents as a function of the dc limiting reactor size.



Overcurrent protection time

The last step in the proposed methodology is to analyse whether the time in which the VSC-HVdc stations experience an overcurrent is lower than the time needed for a particular dc breaker technology to take action and interrupt the fault current. The overcurrent protection times, as a function of the analysed dc limiting reactor sizes, are displayed in Figure 7.28¹⁶.

Taking into account (7.20), and the times shown in Figure 7.28, the passive resonant and the Hybrid II dc breakers cannot be used to isolate the fault in case of MTdc network configurations with ground or metallic return.

If the Hybrid I dc breakers are used, dc limiting reactors higher than 100 mH are needed to allow a successful fault interruption. On the other hand, if the solid-state dc breakers are used, the dc limiting reactors need to be higher than 50 mH to protect the VSC-HVdc stations, and the MTdc network, against dc faults.

¹⁶ For the symmetric monopole configuration, only VSC1 suffers with overcurrents higher than 2 pu if dc limiting reactors of less than 10 mH are used. That is why most columns in Figure 7.28 (b) display *No Overcurrent*. If a reactor size of 50 mH or higher is employed at VSC1, any dc breaker technology can be used to isolate the faulty line as the converters do not experience any overcurrents.

In this case study, the line transport delay is equal to 1.1 ms and the current direction method needs 0.6 ms to detect the fault. As shown in (7.20), for successful interruption of a dc fault, the fault needs to be detected and isolated before the VSC-HVdc terminals experience overcurrents.

Therefore, the total dc fault interruption time is 2.7 ms if a solid-state dc breaker is used, 3.7 ms for the Hybrid I dc breaker and higher than 30 ms for the other two technologies.

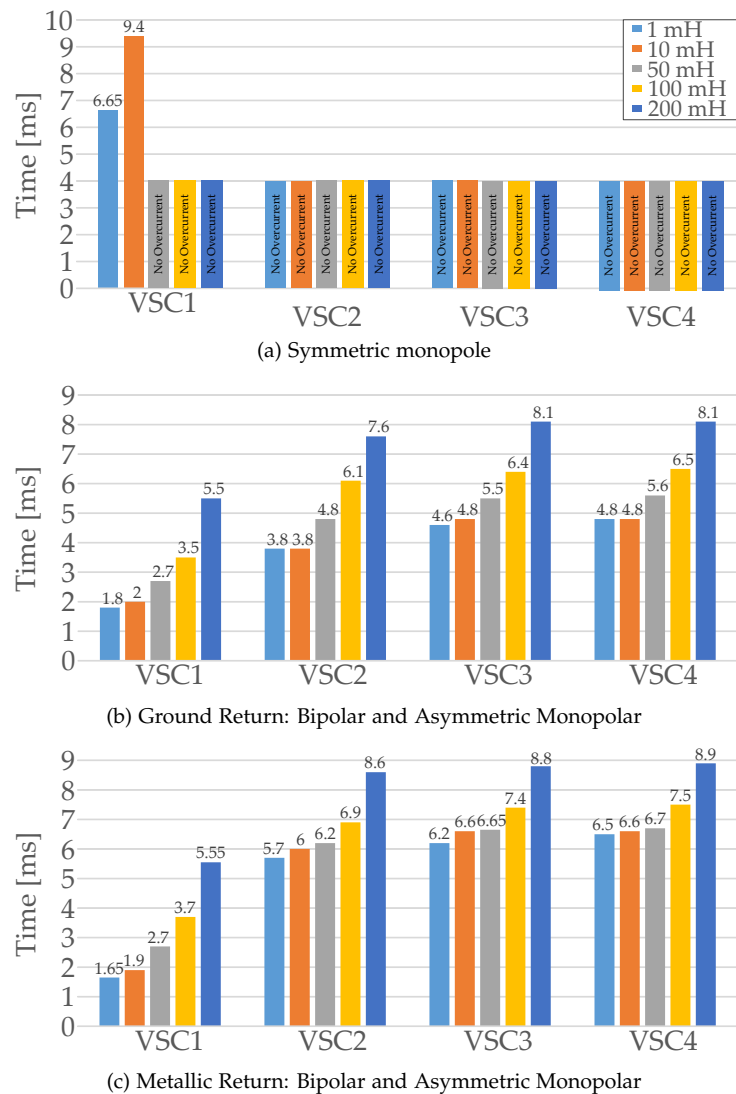


Figure 7.28: Overcurrent protection triggering time as a function of the dc limiting reactor size.

7.8 Conclusion

The results have shown that in case of an ac contingency, a less strict guide code, i.e. a gride code that does not impose 100% reactive power current injection from the voltage-source converters, helps the MTdc network to ride through the fault. If grid codes cannot be softened, the solution is to install dc choppers at the VSC-HVdc terminals and have fast power reduction capability at the generating nodes. Additionally, with control strategies in which the number of nodes controlling the MTdc network direct voltage is higher, such as the distributed voltage control strategy, it is easier to keep the MTdc network operation without interruptions, as more terminals compensate for the lost power during and after the ac fault.

On the other hand, a methodology proposed to study the effects of dc contingencies on MTdc networks has shown that different VSC-HVdc configurations have different fault current development and fault levels.

Amongst all the VSC-HVdc configurations examined, the symmetric monopolar has the best fault response, especially in combination with small dc limiting reactors. The results from the case study performed in this chapter shows that for dc limiting reactors higher than 50 mH, the converters did not experience overcurrents and that the fault current died out after approximately 30 ms, i.e. in less than two ac network cycles.

However, if the power to be transmitted is such that bipolar configurations are needed, the configuration with metallic return, although it has a higher installation capital costs, has a superior performance with regard to dc faults than the same configuration with ground return. In conclusion, a successful dc fault isolation, in configurations with ground or metallic return, will require full semiconductor breakers or Hybrid I breakers, with the additional presence of dc limiting reactors.

8

Small-signal Analysis

Anyone who believes exponential growth can go on forever in a finite world is either a madman or an economist.

Kenneth Ewart Boulding - 1973 Energy reorganisation act
Hearings, p. 248

The large signal models developed in Part III, Dynamic Analysis, through Chapter 4 to Chapter 6, were used in Chapter 7 to study the transient stability of MTdc networks. However, these models are non linear and difficult to use to study the small-signal stability of the overall MTdc system. The aim of the current chapter is to develop a small-signal model which will allow to determine what are the main variables affecting the small-signal stability of MTdc networks. The chapter starts by deriving the linear model of the MTdc grid, and a numerical example is carried out to determine the locations of the eigenvalues for the five-terminal network analysed in the first case study of Chapter 6. After that, a linear model of a voltage-source converter is derived, since the MTdc networks stability will greatly depend on the performance, control strategy and tuning of its power electronic converters. Using the obtained state matrix, which includes the converter hardware and control variables, the control tuning and dynamic response of the VSC are optimised using a multi-objective genetic algorithm. The optimisation algorithm outputs the converter control gains to optimise the location of the converter small-signal model eigenvalues. The results of the control tuning optimisation are validate against results from the large signal model, developed in Chapter 4, and against experimental measurements obtained from a voltage-source converter operating as a STATCOM. Finally, an eigenvalue sensitivity analysis is performed to evaluate the robustness of the voltage-source converters against parametric variations in its hardware components and control gain values.

- 8.1. Linear model of MTdc Networks
- 8.2. Linear model of Voltage-Source Converters
- 8.3. VSC-HVdc Control Tuning Optimisation
- 8.4. Small-Signal Model versus Experimental Results: VSC Model Validation
- 8.5. Eigenvalue Sensitivity Analysis
- 8.6. Conclusion

This chapter is based on the following publication:

R. Teixeira Pinto, S. F. Rodrigues, P. Bauer, and J. Pierik, "Optimal Control Tuning of Grid Connected Voltage Source Converters using a Multi-Objective Genetic Algorithm," in *Power Conversion Intelligent Motion Conference (PCIM Europe)*, Nuremberg, Germany, 14 - 16 May 2013, pp. 1-8.

8.1 Linear model of MTdc Networks

A small-signal model (SSM) is a linearised model of a non-linear system around an operating point. There are mainly two different methods to achieve linearisation: analytical and numerical [215]. This work uses the analytical approach where a variable, x , is expanded in a small-signal part, \tilde{x} , and a steady-state part, X_0 . The same procedure then applies to a non-linear function, f :

$$f(x_1, x_2) = \tilde{f}(\tilde{x}_1, \tilde{x}_2) + F(X_{01}, X_{02}) \quad (8.1)$$

where;

\tilde{f} is the small-signal part of function f ;

F is the steady-state part of function f ;

\tilde{x} is the small-signal part of x and;

X_0 is the steady-state part of x .

For linear models it is possible to show that:

$$\begin{cases} \dot{\mathbf{x}} = \dot{\tilde{\mathbf{x}}} + \dot{\mathbf{X}}_0 = \mathbf{A}(\tilde{\mathbf{x}} + \mathbf{X}_0) + \mathbf{B}(\tilde{\mathbf{u}} + \mathbf{U}_0) = \mathbf{A}\tilde{\mathbf{x}} + \mathbf{B}\tilde{\mathbf{u}} + \mathbf{A}\mathbf{X}_0 + \mathbf{B}\mathbf{U}_0 \\ \mathbf{y} = \tilde{\mathbf{y}} + \mathbf{Y}_0 = \mathbf{C}(\tilde{\mathbf{x}} + \mathbf{X}_0) + \mathbf{D}(\tilde{\mathbf{u}} + \mathbf{U}_0) = \mathbf{C}\tilde{\mathbf{x}} + \mathbf{D}\tilde{\mathbf{u}} + \mathbf{C}\mathbf{X}_0 + \mathbf{D}\mathbf{U}_0 \end{cases} \quad (8.2)$$

Thus, once all the equations in a model have been linearised, its small-signal model can be represented via a state-space matrix form as:

$$\begin{cases} \dot{\tilde{\mathbf{x}}} = \mathbf{A}\tilde{\mathbf{x}} + \mathbf{B}\tilde{\mathbf{u}} \\ \tilde{\mathbf{y}} = \mathbf{C}\tilde{\mathbf{x}} + \mathbf{D}\tilde{\mathbf{u}} \end{cases} \quad (8.3)$$

where;

$\tilde{\mathbf{x}}$ represents the small-signal changes in the state variables;

$\tilde{\mathbf{u}}$ represents the small-signal changes in the input variables;

$\tilde{\mathbf{y}}$ represents the small-signal changes in the output variables and;

$\dot{\tilde{\mathbf{x}}}$ represents the time derivative of the small-signal state variables.

On the other hand, the steady-state model is given by:

$$\begin{cases} \dot{\mathbf{X}}_0 = \mathbf{A}\mathbf{X}_0 + \mathbf{B}\mathbf{U}_0 = \mathbf{0} \\ \mathbf{Y}_0 = \mathbf{C}\mathbf{X}_0 + \mathbf{D}\mathbf{U}_0 \end{cases} \quad (8.4)$$

where;

\mathbf{X}_0 represents the steady-state state variables;

\mathbf{U}_0 represents the steady-state input variables and;

\mathbf{Y}_0 represents the steady-state output variables.

The dynamic model of MTdc networks, derived in Chapter 4, was already represented in a state-space matrix form, which means that model is already linear (see (4.50)). Therefore, the same state-space matrices derived for the dynamic model of MTdc networks in Chapter 4 can be used for the small-signal model.

Numerical Example

Using (4.53), it is possible to calculate the state matrix, \mathbf{A} , for the MTdc network shown in Figure 6.2 as¹:

¹ See the first case study of Chapter 6 in Section 6.2.

$$\mathbf{A} = \begin{pmatrix} 0 & 0 & 0 & 0 & 0 & 0 & 0 & -11933 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -11633 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -12255 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 11666 & 11666 & -11666 & -11666 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 17488 & 17488 & -17488 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 8403 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 9653 \\ 0.65 & 0 & 0 & -0.65 & 0 & 0 & 0 & -10.47 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0.52 & 0 & -0.52 & 0 & 0 & 0 & 0 & -10.47 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0.13 & 0 & -0.13 & 0 & 0 & 0 & -10.47 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0.26 & -0.26 & 0 & 0 & 0 & 0 & 0 & -10.47 & 0 & 0 \\ 0 & 0 & 0.87 & 0 & -0.87 & 0 & 0 & 0 & 0 & 0 & 0 & -10.47 & 0 \\ 0 & 0 & 0 & 0 & 0.20 & 0 & -0.20 & 0 & 0 & 0 & 0 & 0 & -10.47 \end{pmatrix} \quad (8.5)$$

Solving $\det(\mathbf{A} - \lambda \cdot \mathbf{I}) = 0$, the eigenvalues, λ , of the state matrix \mathbf{A} are obtained as:

$$\lambda = \begin{pmatrix} -5.236 + 180.0i \\ -5.236 - 180.0i \\ -5.236 + 152.6i \\ -5.236 - 152.6i \\ -5.236 + 82.55i \\ -5.236 - 82.55i \\ -5.236 + 61.94i \\ -5.236 - 61.94i \\ 0 \\ -5.236 + 42.85i \\ -5.236 - 42.85i \\ -5.236 + 30.53i \\ -5.236 - 30.53i \end{pmatrix} \quad (8.6)$$

Figure 8.1 shows the location of the eigenvalues obtained in (8.6). Due to the eigenvalue located at the origin of the cartesian plane, the MTdc network system is marginally stable, which was also the case for the VSC-HVdc dynamic model when the proportional gain, K_p^W , was null (see Figure 4.25).

It is possible to demonstrate that the determinant of the state matrix \mathbf{A} , calculated by (4.53), is always null. Therefore, a MTdc network will have a pole at the origin and will, thus, always be a marginally stable system [32]. To guarantee the stability of a MTdc network, feedback control of the system direct voltages is necessary although not sufficient, as discussed in Section 5.1 (see (5.1)).

The eigenvalues shown in (8.6), except for the one at the origin, have all the same real part, equal to $-R_{dc}/2L_{dc}^2$.

It is difficult to derive a general analytical expression to calculate the eigenvalues of a MTdc network. However, for some simplified examples it is possible to obtain analytical expressions. Figure 8.2 shows a two-terminal dc network, and a special case of a 3-terminal dc network, in which all the nodes have the same capacitance, C , and all the transmission lines have the same resistance, R , and inductance, L .

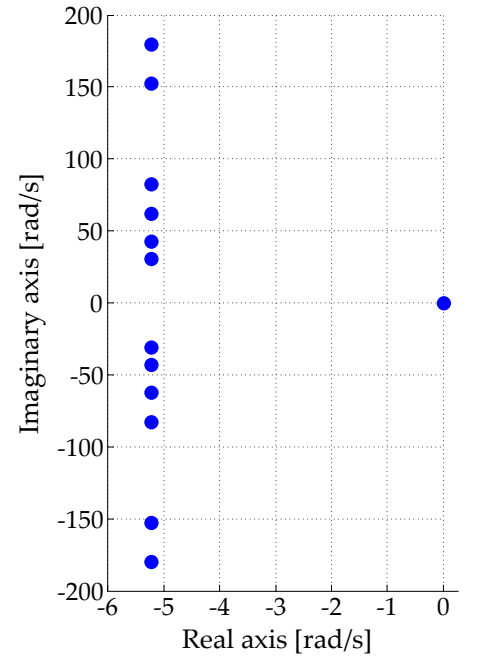


Figure 8.1: Eigenvalues from the MTdc network shown in Figure 6.2.

² This happens because, although the lines have different lengths, the unit-length resistance and unit-length inductance of all the MTdc network cables in the case study have the same values, 0.200 Ω/km and 19.10 mH/km, respectively (see Table 6.3).

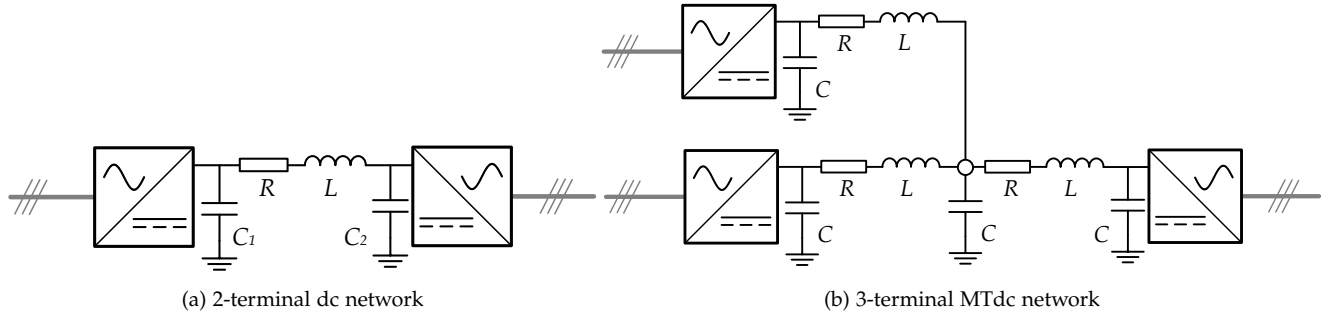


Figure 8.2: Example of dc networks.

The two-terminal dc network has the following state matrix:

$$\mathbf{A}_2 = \begin{pmatrix} 0 & 0 & -1/C_1 \\ 0 & 0 & 1/C_2 \\ 1/L & -1/L & -R/L \end{pmatrix} \quad (8.7)$$

³ For the two-terminal dc network, the same eigenvalues were obtained in [32] using a different approach named Jacobian transfer matrix.

Hence, its eigenvalues are given as³:

$$\begin{cases} \lambda_1 = 0 \\ \lambda_{2,3} = -\frac{R}{2L} \pm \sqrt{\frac{R^2}{4L^2} - \frac{1}{L} \left(\frac{1}{C_1} + \frac{1}{C_2} \right)} \end{cases} \quad (8.8)$$

On the other hand, the state matrix for the 3-terminal MTdc network is given as:

$$\mathbf{A}_3 = \begin{pmatrix} 0 & 0 & 0 & 0 & -1/C & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & -1/C & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & -1/C \\ 0 & 0 & 0 & 0 & 1/C & 1/C & 1/C \\ 1/L & 0 & 0 & -1/L & -R/L & 0 & 0 \\ 0 & 1/L & 0 & -1/L & 0 & -R/L & 0 \\ 0 & 0 & 1/L & -1/L & 0 & 0 & -R/L \end{pmatrix} \quad (8.9)$$

The eigenvalues of the special 3-terminal MTdc network are:

$$\begin{cases} \lambda_1 = 0 \\ \lambda_{2,3} = -\frac{R}{2L} \pm \sqrt{\frac{R^2}{4L^2} - \frac{1}{LC}} \\ \lambda_{4,5} = -\frac{R}{2L} \pm \sqrt{\frac{R^2}{4L^2} - \frac{4}{LC}} \end{cases} \quad (8.10)$$

The resulting eigenvalues show that both dc networks are marginally stable, i.e. they have an eigenvalue at the origin of the cartesian plane, their real part is given by R/L , whereas their complex part depend on the MTdc network R, L, C parameters.

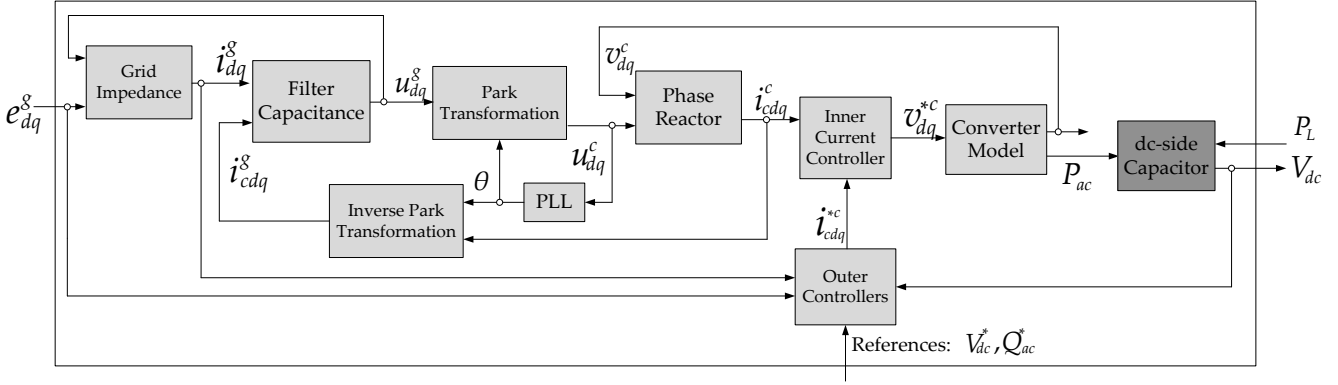


Figure 8.4: Voltage-source converter small-signal model.

In Chapter 4, since the PLL was omitted, there was only one (dq) reference frame and both the grid and the converter currents and voltages were represented in that frame.

In reality, the grid and the converter have distinct (dq) reference frames [32,216]. Hence, when the PLL is included in the VSC model, it is necessary to distinguish between these two frames. This is why in Figure 8.3 and Figure 8.4 the converter voltage is denoted v_{dq}^c , whereas the grid voltage is denoted e_{dq}^g .

Thus, the superscripts g and c indicate, respectively, the grid and the converter (dq) rotating reference frames. More details are given next when the PLL controller model is explained.

Grid Side Inductance

The small-signal model of the VSC-HVdc system phase reactor, can be obtained by manipulating the grid-side current equations: (4.7):

$$\begin{cases} L_g \frac{d}{dt} (i_d^g) = e_d^g - u_d^g - R_g i_d^g + \omega L_g i_q^g \\ L_g \frac{d}{dt} (i_q^g) = e_q^g - u_q^g - R_g i_q^g - \omega L_g i_d^g \end{cases} \quad (8.11)$$

where;

L_g is the grid-side inductance value [H];

R_g is the grid-side resistance [Ω];

i_{dq}^g is the grid current in the grid (dq) frame [A];

e_{dq}^g is the grid voltage in the grid (dq) frame [V];

u_{dq}^g is the LCL-filter voltage in the grid (dq) frame [V].

Expanding the first equation on (8.11) with regard to (8.1) yields⁵:

$$L_g \dot{\tilde{i}}_d^g = (\tilde{e}_d^g + E_{d0}^g) - (\tilde{u}_d^g + U_{d0}^g) - R_g (\tilde{i}_d^g + I_{d0}^g) + L_g (\tilde{\omega} + \omega_0) (\tilde{i}_q^g + I_{q0}^g) \quad (8.12)$$

Rearranging (8.12), and only taking in consideration the small-signal variations, the grid-side current can be written as:

$$L_g \dot{\tilde{i}}_{dq}^g = \tilde{e}_{dq}^g - \tilde{u}_{dq}^g - R_g \tilde{i}_{dq}^g - \mathbf{j} L_g \omega_0 \tilde{i}_{dq}^g - \mathbf{j} L_g I_{dq0}^g \tilde{\omega} \quad (8.13)$$

⁵ The derivative of the d-axis grid-side steady-state current is not present on (8.12) as $d(I_{d0}^g)/dt = 0$.

By using the small-signal approach it is also possible to obtain steady-state models from the dynamic models. For example, the steady-state current in the d-axis can be calculated by:

$E_{d0}^g - U_{d0}^g - R_g I_{d0}^g + L_g \omega_0 I_{q0}^g = 0$.

Nonetheless, steady-state models are not further developed in the thesis.

where;

$\dot{i}_{dq}^{\tilde{s}}$ is the grid small-signal current derivative in the grid rotating frame [A/s];

$i_{dq}^{\tilde{s}}$ is the grid small-signal current in the grid rotating frame [A];

$e_{dq}^{\tilde{s}}$ is the grid small-signal voltage in the grid rotating frame [V];

$u_{dq}^{\tilde{s}}$ is the LCL-filter small-signal voltage in the grid rotating frame [V];

$I_{dq0}^{\tilde{s}}$ is the grid steady-state current in the grid rotating frame [A] and;

$\tilde{\omega}$ is the grid small-signal angular frequency [rad/s].

Hence, according to (8.13), the first two state variables $(\tilde{x}_1, \tilde{x}_2)$ of the VSC small-signal model are given by $(\tilde{i}_d^{\tilde{s}}, \tilde{i}_q^{\tilde{s}})$, respectively. Rewriting (8.13) in a state-space matrix form gives:

$$\begin{bmatrix} \dot{\tilde{i}}_d^{\tilde{s}} \\ \dot{\tilde{i}}_q^{\tilde{s}} \end{bmatrix} = \begin{bmatrix} -R_g & +L_g\omega_0 \\ -L_g\omega_0 & -R_g \end{bmatrix} \begin{bmatrix} \tilde{i}_d^{\tilde{s}} \\ \tilde{i}_q^{\tilde{s}} \end{bmatrix} + \begin{bmatrix} 1 & 0 & -1 & 0 & +L_g I_{q0}^{\tilde{s}} \\ 0 & 1 & 0 & -1 & -L_g I_{d0}^{\tilde{s}} \end{bmatrix} \begin{bmatrix} \tilde{e}_d^{\tilde{s}} \\ \tilde{e}_q^{\tilde{s}} \\ u_{dq}^{\tilde{s}} \\ u_q^{\tilde{s}} \\ \tilde{\omega} \end{bmatrix} \quad (8.14)$$

Filter Capacitance

The equations of the capacitor voltage in the LCL filter are dual, i.e. analogous, to the inductor current equations shown in (8.11). In the grid-side (dq) frame the LCL capacitor voltages are given as:

$$C_f \frac{d}{dt} (u_{dq}^{\tilde{s}}) = i_{dq}^{\tilde{s}} - i_{cdq}^{\tilde{s}} - \mathbf{j}\omega C_f u_{dq}^{\tilde{s}} \quad (8.15)$$

Expanding (8.15) the same way it was done on (8.12), yields:

$$C_f \dot{u}_{dq}^{\tilde{s}} = \tilde{i}_{dq}^{\tilde{s}} - \tilde{i}_{cdq}^{\tilde{s}} - \mathbf{j}C_f \omega_0 u_{dq}^{\tilde{s}} - \mathbf{j}C_f U_{dq0}^{\tilde{s}} \tilde{\omega} \quad (8.16)$$

where;

C_f is LCL-filter capacitance [F].

$\tilde{i}_{cdq}^{\tilde{s}}$ is the VSC small-signal current in the grid rotating frame [A];

$u_{dq}^{\tilde{s}}$ is the LCL-filter small-signal voltage in the grid rotating frame [V]

and;

$U_{dq0}^{\tilde{s}}$ is the LCL-filter steady-state voltage in the grid rotating frame [V].

Similarly, (8.16) can be written in state-space form as:

$$\begin{bmatrix} \dot{\tilde{u}}_d^{\tilde{s}} \\ \dot{\tilde{u}}_q^{\tilde{s}} \end{bmatrix} = \begin{bmatrix} 0 & +C_f\omega_0 \\ -C_f\omega_0 & 0 \end{bmatrix} \begin{bmatrix} \tilde{u}_d^{\tilde{s}} \\ \tilde{u}_q^{\tilde{s}} \end{bmatrix} + \begin{bmatrix} 1 & 0 & -1 & 0 & +C_f U_{q0}^{\tilde{s}} \\ 0 & 1 & 0 & -1 & -C_f U_{d0}^{\tilde{s}} \end{bmatrix} \begin{bmatrix} \tilde{i}_d^{\tilde{s}} \\ \tilde{i}_q^{\tilde{s}} \\ \tilde{e}_d^{\tilde{s}} \\ \tilde{e}_q^{\tilde{s}} \\ \tilde{\omega} \end{bmatrix} \quad (8.17)$$

Hence, the third and fourth state variables $(\tilde{x}_3, \tilde{x}_4)$ of the VSC small-signal model are then given by $(\tilde{u}_d^{\tilde{s}}, \tilde{u}_q^{\tilde{s}})$, respectively.

Converter-Side Inductance: Phase Reactor

The small-signal equations for the phase reactor are similar to the ones presented in (8.13). The main difference is that they are given in the converter (dq) reference frame, i.e.:

$$L_c \dot{i}_{cdq}^{\tilde{c}} = u_{dq}^{\tilde{c}} - v_{dq}^{\tilde{c}} - R_c i_{cdq}^{\tilde{c}} - \mathbf{j} L_c \omega_0 i_{cdq}^{\tilde{c}} - \mathbf{j} L_c I_{cdq0}^{\tilde{c}} \tilde{\omega} \quad (8.18)$$

where;

L_c is phase reactor inductance [H];

R_c is phase reactor resistance [Ω];

$\dot{i}_{cdq}^{\tilde{c}}$ is the VSC small-signal current derivative in the VSC rotating frame [A/s];

$i_{cdq}^{\tilde{c}}$ is the VSC small-signal current in the VSC rotating frame [A];

$u_{dq}^{\tilde{c}}$ is the LCL-filter small-signal voltage in the VSC rotating frame [V] and;

$v_{dq}^{\tilde{c}}$ is the VSC small-signal voltage in the VSC rotating frame [V] and;

$I_{cdq0}^{\tilde{c}}$ is the VSC steady-state current in the VSC rotating frame [A].

Thus, (8.18) can be written in state-space form as:

$$\begin{bmatrix} \dot{i}_{cd}^{\tilde{c}} \\ \dot{i}_{cq}^{\tilde{c}} \end{bmatrix} = \begin{bmatrix} -R_c & +L_c \omega_0 \\ -L_c \omega_0 & -R_c \end{bmatrix} \begin{bmatrix} i_{cd}^{\tilde{c}} \\ i_{cq}^{\tilde{c}} \end{bmatrix} + \begin{bmatrix} 1 & 0 & -1 & 0 & +L_c I_{cq0}^{\tilde{c}} \\ 0 & 1 & 0 & -1 & -L_c I_{cd0}^{\tilde{c}} \end{bmatrix} \begin{bmatrix} u_d^{\tilde{c}} \\ u_q^{\tilde{c}} \\ v_d^{\tilde{c}} \\ v_q^{\tilde{c}} \\ \tilde{\omega} \end{bmatrix} \quad (8.19)$$

Hence, the fifth and sixth state variables (\tilde{x}_5, \tilde{x}_6) of the VSC small-signal model are then given by $(i_{cd}^{\tilde{c}}, i_{cq}^{\tilde{c}})$, respectively.

VSC Output DC Capacitor

As discussed in Chapter 4, for the direct voltage controller to be linear, it is necessary to control the square of the VSC dc-side voltage, $W_{dc} = V_{dc}^2$. Expanding (4.27), which gives the energy stored in the dc-side capacitor, according to (8.1) yields:

$$\begin{cases} \frac{d}{dt} (\tilde{W}_{dc} + W_{dc0}) = \frac{2}{C} (\tilde{P}_c + P_{c0} - \tilde{P}_L - P_{L0}) \\ \Rightarrow \dot{\tilde{W}}_{dc} = \frac{2}{C} (\tilde{P}_c - \tilde{P}_L) \end{cases} \quad (8.20)$$

where;

\tilde{P}_c is the VSC small-signal active power [W] and;

\tilde{P}_L is the small-signal active power flowing into the dc line [W].

Hence, the seventh state variable, \tilde{x}_7 , of the VSC small-signal model is represented by \tilde{W}_{dc} .

The power flowing into the MTdc network can be taken as an input to the small-signal model and does not need further development. However, the VSC active power \tilde{P}_c depends on other state

variables, and needs to be further expanded as a function of the VSC voltages and currents:

$$\tilde{P}_c = \tilde{v}_d^c I_{cd0}^c + \tilde{v}_q^c I_{cq0}^c + i_{cd}^c V_{d0}^c + i_{cq}^c V_{q0}^c \quad (8.21)$$

where;

V_{dq0}^c is the VSC steady-state voltage in the VSC rotating frame [V].

All the state variables presented thus far are related to the physical components, i.e. hardware, of a voltage-source converter. Next, the state variables belonging to the control structure of the VSC are presented, starting with the inner-current controller.

Inner Current Controller

The goal of the ICC is to set the converter voltage, \tilde{v}_{dq}^c , so that the converter current, i_{cdq}^c , becomes the same as the reference current, i_{cdq}^{*c} , given by the outer controllers. As shown in Chapter 4, the ICC employs two PI controllers, one for the d-axis and another for the q-axis of the (dq) reference frame. The PI controllers used for the ICC are shown in Figure 8.5.

If the difference between the VSC current reference – which comes from the outer controllers – and the VSC current is taken as a state variable, it is possible to write [216]:

$$\begin{cases} \dot{\tilde{\epsilon}}_{id} = \tilde{i}_d^{*c} - \tilde{i}_d^c \\ \dot{\tilde{\epsilon}}_{iq} = \tilde{i}_q^{*c} - \tilde{i}_q^c \end{cases} \quad (8.22)$$

where;

$\dot{\tilde{\epsilon}}_{id}$ is the ICC d-axis controller small-signal error derivative [A] and;
 $\dot{\tilde{\epsilon}}_{iq}$ is the ICC q-axis controller small-signal error derivative [A].

As shown in the VSC model, displayed in Figure 8.3 and Figure 4.16, the output of the ICC is the voltage reference, \tilde{v}_{dq}^{*c} , for the PWM block.

Assuming the converter model to be ideal, as previously done in Chapter 4 – see (4.11) – the VSC voltage is equal the reference voltage from the ICC with one time step delay, i.e.:

$$\tilde{v}_{dq}^c(k+1) \approx \tilde{v}_{dq}^{*c}(k) \quad (8.23)$$

Therefore, applying (8.1) to the output of the ICC given in (4.20), yields:

$$\begin{cases} \tilde{v}_d^{*c} = \tilde{v}_d^c = \tilde{u}_d^c - K_p \cdot \dot{\tilde{\epsilon}}_{id} - K_i \cdot \tilde{\epsilon}_{id} + L_c \omega_0 i_{cq}^c + L_c I_{cq0}^c \tilde{\omega} \\ \tilde{v}_q^{*c} = \tilde{v}_q^c = \tilde{u}_q^c - K_p \cdot \dot{\tilde{\epsilon}}_{iq} - K_i \cdot \tilde{\epsilon}_{iq} - L_c \omega_0 i_{cd}^c - L_c I_{cd0}^c \tilde{\omega} \end{cases} \quad (8.24)$$

where;

$\tilde{\epsilon}_{id}$ is the ICC d-axis controller small-signal error [As] and;

$\tilde{\epsilon}_{iq}$ is the ICC q-axis controller small-signal error [As].

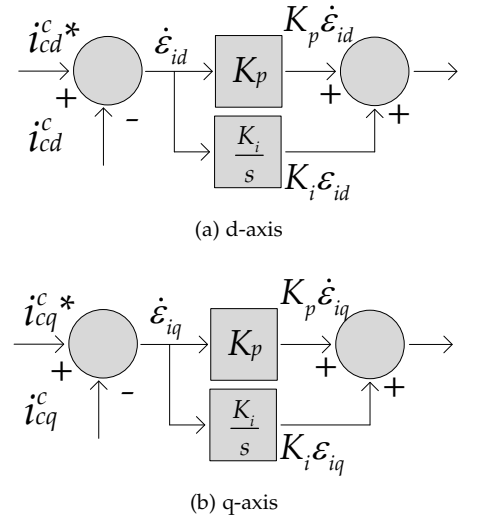


Figure 8.5: PI Controllers of the VSC inner-current controller.

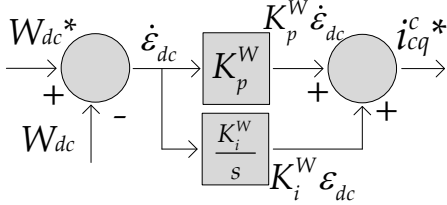


Figure 8.6: PI Controller of the VSC direct voltage controller.

Isolating the previous equation with regard to $(\dot{\tilde{\epsilon}}_{id}, \dot{\tilde{\epsilon}}_{iq})$, gives:

$$\begin{cases} \dot{\tilde{\epsilon}}_{id} = (1/K_p) (\tilde{u}_d^c - \tilde{v}_d^c - K_i \cdot \tilde{\epsilon}_{id} + L_c \omega_0 \tilde{i}_{cq}^c + L_c I_{cq0}^c \tilde{\omega}) \\ \dot{\tilde{\epsilon}}_{iq} = (1/K_p) (\tilde{u}_q^c - \tilde{v}_q^c - K_i \cdot \tilde{\epsilon}_{iq} - L_c \omega_0 \tilde{i}_{cd}^c - L_c I_{cd0}^c \tilde{\omega}) \end{cases} \quad (8.25)$$

Hence, the eight and ninth state variables $(\tilde{x}_8, \tilde{x}_9)$ of the VSC small-signal model are given by $(\tilde{\epsilon}_{id}, \tilde{\epsilon}_{iq})$, respectively.

Direct Voltage Controller

The reference current for the ICC q-axis, \tilde{i}_{cq}^{*c} , is provided by the direct voltage controller, which employs a PI compensator as shown in Figure 8.6, therefore:

$$\begin{cases} \dot{\tilde{\epsilon}}_{dc} = W_{dc}^* - W_{dc} \\ \tilde{i}_{cq}^{*c} = K_p^W \cdot \dot{\tilde{\epsilon}}_{dc} + K_i^W \cdot \tilde{\epsilon}_{dc} \end{cases} \quad (8.26)$$

where;

$\dot{\tilde{\epsilon}}_{dc}$ is the direct voltage controller small-signal error derivative [V]
and;

$\tilde{\epsilon}_{dc}$ is the direct voltage controller small-signal error [Vs].

Hence, the tenth state variable, \tilde{x}_{10} , of the VSC small-signal model is given by $\tilde{\epsilon}_{dc}$.

Reactive Power Controller (RPC)

The reactive power at the ac grid side, q_g , is calculated according to the second equation on (4.21). Accordingly, the small-signal model of the grid-side reactive power, \tilde{q}_g , is given by expanding (4.21) using (8.1):

$$\tilde{q}_g = \tilde{e}_q^g \cdot I_{d0}^g - \tilde{e}_d^g \cdot I_{q0}^g + \tilde{i}_d^g \cdot E_{q0}^g - \tilde{i}_q^g \cdot E_{d0}^g \quad (8.27)$$

The reactive power controller also employs a PI compensator, such that (see Figure 8.7):

$$\begin{cases} \dot{\tilde{\epsilon}}_Q = \tilde{q}_g^* - \tilde{q}_g \\ \tilde{i}_{cd}^{*c} = K_p^Q \cdot \dot{\tilde{\epsilon}}_Q + K_i^Q \cdot \tilde{\epsilon}_Q \end{cases} \quad (8.28)$$

where;

$\dot{\tilde{\epsilon}}_Q$ is the reactive power controller small-signal error derivative [VAR]
and;

$\tilde{\epsilon}_Q$ is the reactive controller small-signal error [VAR s].

Hence, the eleventh state variable, \tilde{x}_{11} , of the VSC small-signal model is given by $\tilde{\epsilon}_Q$.

Phase Lock Loop (PLL)

The PLL is responsible for providing a reference angle – or phase – between the grid reference (dq) frame, which rotates synchronously

with the ac system, and the converter (dq) reference frame, which can be arbitrarily set by the converter. After the PLL angle is obtained, the electric quantities – namely voltages and currents – can be transformed from the three-phase (abc) frame, to the two-phase (dq) rotating frames.

One of the most simple ways to execute the PLL controller is to force to zero one of the (dq) components of the LCL-filter voltage so that the VSC becomes synchronised to the ac system [32].

In this thesis, the grid voltage phasor is aligned with the q-axis of the ac grid (dq) reference frame, which means $e_d^s = 0$. On the other hand, the converter filter voltage is aligned with the q-axis of the VSC (dq) reference frame so that $u_d^c = 0$, once the PLL has reached steady-state. Figure 8.8 shows the block and phasor diagram of the VSC PLL controller.

As shown in Figure 8.8 (a), the PLL uses a PI compensator to calculate the angle, θ , between the grid and the converter (dq) rotating frames, i.e.:

$$\begin{cases} \dot{\tilde{\epsilon}}_{pll} = u_d^{*c} - u_d^c \\ \tilde{\omega} = k_p^{pll} \cdot \dot{\tilde{\epsilon}}_{pll} + k_i^{pll} \cdot \tilde{\epsilon}_{pll} \\ \dot{\tilde{\theta}} = \tilde{\omega} \end{cases} \quad (8.29)$$

where;

$\dot{\tilde{\epsilon}}_{pll}$ is the PLL controller small-signal error derivative [V];

$\tilde{\epsilon}_{pll}$ is the reactive controller small-signal error [Vs].

k_p^{pll} is the PLL controller proportional gain [rad/Vs];

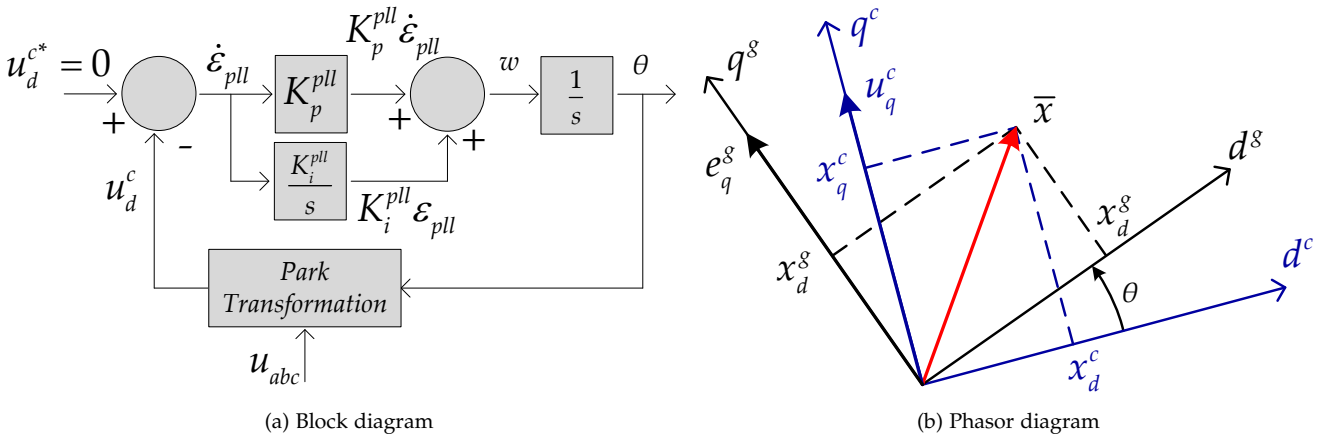
k_i^{pll} is the PLL controller integral gain [rad/Vs²] and;

$\dot{\tilde{\theta}}$ is the PLL small-signal angle derivative [rad/s].

Hence, the twelfth and thirteenth state variables ($\tilde{x}_{12}, \tilde{x}_{13}$) of the VSC small-signal model are given by $(\tilde{\epsilon}_{pll}, \tilde{\theta})$, respectively.

In the VSC-HVdc small-signal model, shown in Figure 8.3, only two variables – the filter-bus voltage (u_{dq}^s) and the converter current (i_{cdq}^c) – need to be transformed from the grid reference frame to the converter reference frame and vice-versa.

Figure 8.8: Phase lock loop controller diagrams.



The direct Park transformation of the filter-bus voltage is accomplished as [216]:

$$\begin{bmatrix} \tilde{u}_d^c \\ \tilde{u}_q^c \end{bmatrix} = \begin{bmatrix} \cos \theta_0 & \sin \theta_0 \\ -\sin \theta_0 & \cos \theta_0 \end{bmatrix} \cdot \begin{bmatrix} \tilde{u}_d^g \\ \tilde{u}_q^g \end{bmatrix} + \begin{bmatrix} -\sin \theta_0 & \cos \theta_0 \\ -\cos \theta_0 & -\sin \theta_0 \end{bmatrix} \cdot \begin{bmatrix} U_{d0}^g \\ U_{q0}^g \end{bmatrix} \cdot \tilde{\theta} \quad (8.30)$$

Instead, the inverse park transformation of converter current is given as:

$$\begin{bmatrix} \tilde{i}_{cd}^g \\ \tilde{i}_{cq}^g \end{bmatrix} = \begin{bmatrix} \cos \theta_0 & -\sin \theta_0 \\ \sin \theta_0 & \cos \theta_0 \end{bmatrix} \cdot \begin{bmatrix} \tilde{i}_{cd}^c \\ \tilde{i}_{cq}^c \end{bmatrix} + \begin{bmatrix} -\sin \theta_0 & -\cos \theta_0 \\ \cos \theta_0 & -\sin \theta_0 \end{bmatrix} \cdot \begin{bmatrix} I_{cd0}^c \\ I_{cq0}^c \end{bmatrix} \cdot \tilde{\theta} \quad (8.31)$$

where;

$\tilde{\theta}$ is the PLL small-signal angle [rad] and;

θ_0 is the PLL steady-state angle [rad].

State and Input Matrices of the VSC Small-Signal Model

The VSC small-signal model, derived in the (dq) rotating frame, contains a total of thirteen state variables.

From the complete set of state variables, the first seven relate to the voltage-source converter hardware, i.e. they are the voltages and currents of the energy storing elements, whereas the remaining six state variables are related to the VSC controllers. The complete set of state variables is given by the following vector:

$$\tilde{\mathbf{x}} = \left[\underbrace{\begin{bmatrix} \tilde{i}_d^g & \tilde{i}_q^g \end{bmatrix}}_{\text{grid-side current}} \underbrace{\begin{bmatrix} \tilde{u}_d^g & \tilde{u}_q^g \end{bmatrix}}_{\text{LCLfilter voltage}} \underbrace{\begin{bmatrix} \tilde{i}_{cd}^c & \tilde{i}_{cq}^c \end{bmatrix}}_{\text{VSC-side current}} \underbrace{\tilde{W}_{dc}}_{\text{dc-side voltage square}} \underbrace{\begin{bmatrix} \tilde{\epsilon}_{id} & \tilde{\epsilon}_{iq} \end{bmatrix}}_{\text{ICC error}} \underbrace{\tilde{\epsilon}_{dc}}_{\text{DVC error}} \underbrace{\tilde{\epsilon}_Q}_{\text{RPC error}} \underbrace{\tilde{\epsilon}_{pll}}_{\text{PLL error}} \underbrace{\tilde{\theta}}_{\text{PLL angle}} \right] \quad (8.32)$$

On the other hand, the complete set of input variables, as displayed in Figure 8.4, is given by:

$$\tilde{\mathbf{u}} = \left[\underbrace{\begin{bmatrix} \tilde{e}_d^g & \tilde{e}_q^g \end{bmatrix}}_{\text{grid-side voltage}} \underbrace{\tilde{P}_L}_{\text{dc-line power}} \underbrace{\tilde{W}_{dc}^*}_{\text{dc-side voltage reference}} \underbrace{\tilde{q}_g^*}_{\text{grid-side reactive power reference}} \right] \quad (8.33)$$

As discussed in the beginning of this chapter, the VSC small-signal model equations can be represented in a state-space matrix form as (see (8.3)):

$$\dot{\tilde{\mathbf{x}}} = \mathbf{A}\tilde{\mathbf{x}} + \mathbf{B}\tilde{\mathbf{u}}$$

The state matrix, \mathbf{A} , and the input matrix, \mathbf{B} , can be obtained by expanding equations (8.13) until (8.31) as a function of the state and input variables, respectively. The resulting state space matrix, \mathbf{A} , and input matrix, \mathbf{B} , are given in Appendix B.3.

8.3 VSC-HVdc Control Tuning Optimisation

After linearising the VSC model, the obtained state matrix can be used to calculate the location of the eigenvalues of the complete system. The control tuning optimisation is then performed by selecting the eight control gains such that the location of the VSC eigenvalues are optimal. For this purpose, a multi-objective GA (MOGA) was applied to achieve optimal control tuning. Figure 8.9 displays the flowchart of the MOGA utilised for the optimisation.

The MOGA optimises the eigenvalues of the small-signal model – obtained from the state matrix \mathbf{A} in (B.1) – by selecting all four pairs VSC control gains:

1. Inner-current controller (ICC): K_p, K_i ;
2. Direct Voltage controller (DVC): K_p^W, K_i^W ;
3. Reactive Power controller (RPC): K_p^Q, K_i^Q and;
4. Phase-locked Loop controller (PLL): K_p^{pll}, K_i^{pll} .

The multi-objective genetic algorithm was given 3 distinctive and conflicting goals:

1. maximise the current-controller bandwidth;
2. optimise the location of the slowest pole;
3. guarantee that the complex part of the control eigenvalues is not too large to avoid oscillations in the VSC dynamic response.

Given the size and complexity of the state matrix \mathbf{A} shown in (B.1), the optimisation was done by numerically evaluating the eigenvalues position for a small low-voltage VSC. The physical characteristics of the converter are given in Table 8.1.

These characteristics are taken from real voltage-source converters, which are used later in Section 8.4, to validate the small-signal model against measurements taken in the laboratory; and in Chapter 9 where a MTdc network is built to test the distributed voltage control strategy presented in Chapter 6.

Parameter	Symbol	Value	Unit
VSC Rated Power	S_{vsc}	5000	VA
VSC ac-side Voltage	V_c	380	V
Grid-side Inductance	L_g	1.5	mH
Grid-side Resistance	R_g	0.2	Ω
Filter Capacitance	C_f	20	μF
Converter Inductance	L_c	1.5	mH
Converter Resistance	R_c	0.2	Ω
DC-Side Voltage	V_{dc}	700	V
DC-Side Capacitor	C_{dc}	500	μF

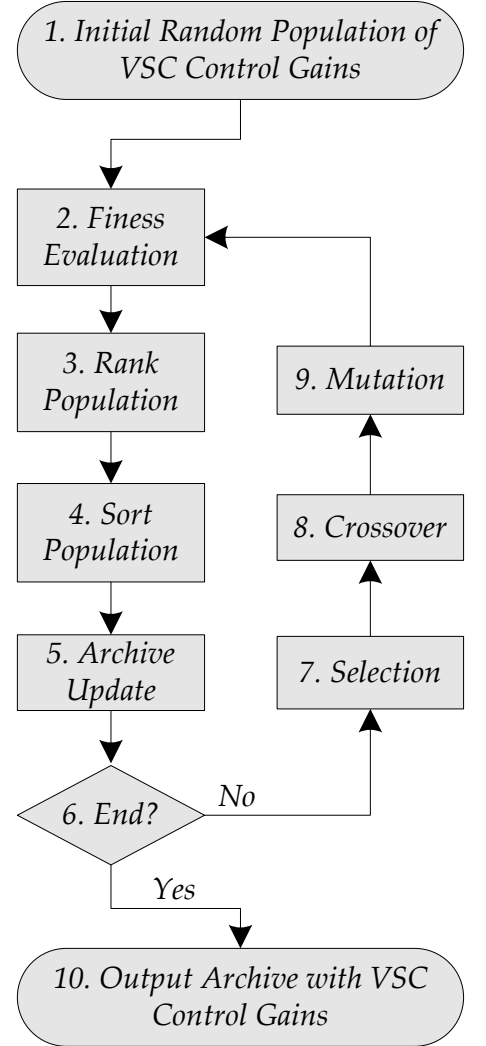


Figure 8.9: Multi-objective genetic algorithm (MOGA) flowchart.

Table 8.1: Rated parameters of the voltage-source converter used in the laboratory experiments.

Figure 8.10: Pareto front obtained from the MOGA optimal VSC control tuning.

⁶ Each blue circle in the Pareto front represents a set of the 8 VSC controller gains and, each set is positioned in the Pareto front according to the 3 optimisation goals, i.e.: inner current controller bandwidth, slowest pole and largest control pole complex (oscillatory) part. It is important to note that the ac-grid current eigenvalues ($\tilde{i}_d^s, \tilde{i}_q^s$) and the LCL filter-voltage eigenvalues ($\tilde{u}_d^s, \tilde{u}_q^s$), were not included in the third optimisation goal because their complex part remains largely unchanged, even upon action of the closed-loop control, as will be shown in Section 8.5.

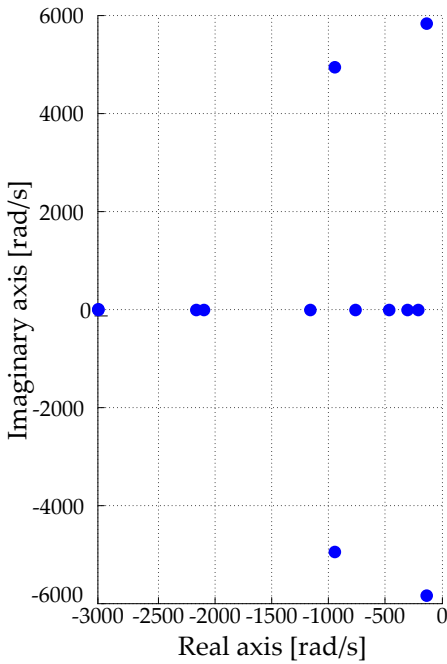
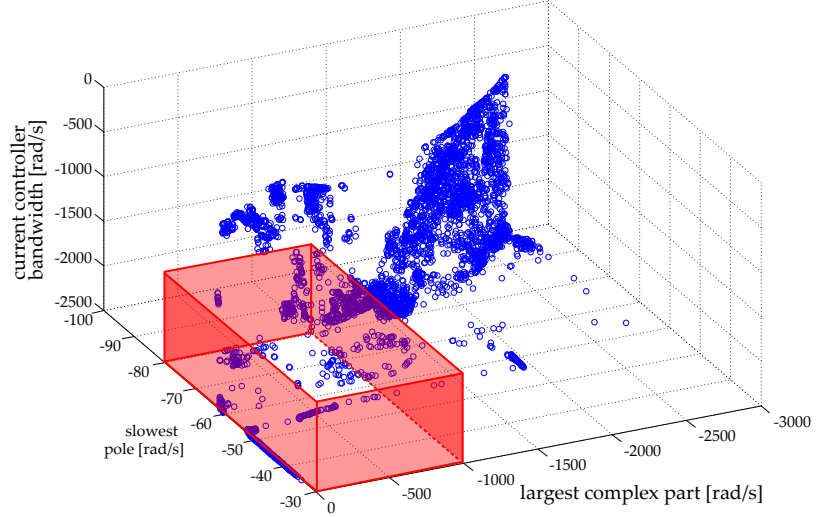


Figure 8.11: Location of the VSC eigenvalues with the control gains from Table 8.3.

Table 8.2: Real and complex parts of the VSC system eigenvalues.

Eigenvalue	Real Part [rad/s]	Complex Part [rad/s]
\tilde{i}_d^s	-138	5829
\tilde{i}_q^s	-138	-5829
\tilde{u}_d^s	-947	4945
\tilde{u}_q^s	-974	-4945
\tilde{i}_{cd}^c	-3000	2.2
\tilde{i}_{cq}^c	-3000	-2.2
\tilde{W}_{dc}	-1162	0
\tilde{e}_{id}	-2171	0
\tilde{e}_{iq}	-2099	0
\tilde{e}_{dc}	-762	0
\tilde{e}_Q	-465	0
\tilde{e}_{pll}	-309	0
$\tilde{\theta}$	-213	0



The results obtained from the MOGA are shown in Figure 8.10. They represent a Pareto front obtained from the VSC control tuning optimisation⁶. Solutions lying inside of the red box in the Pareto Front shown will have all the desired control characteristics: a high-bandwidth inner current controller loop, a faster slowest pole, and poles with small complex parts.

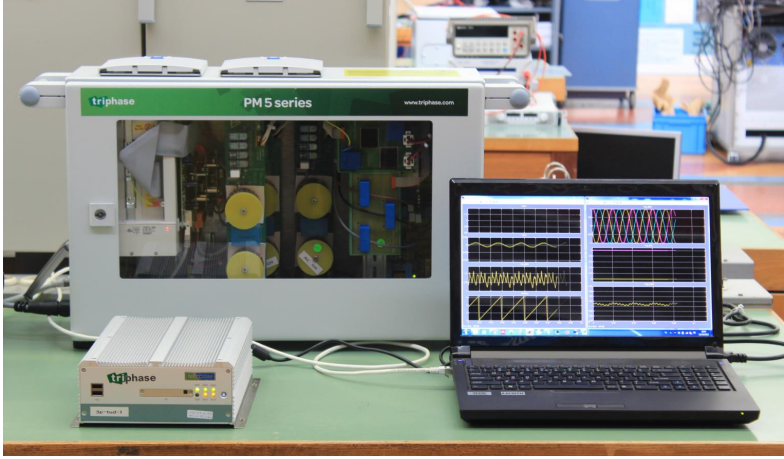
From all the solutions inside the Pareto front shown, the one selected for the laboratory test has the slowest pole at circa 60 rad/s, the inner current controller bandwidth of circa 2.0 krad/s, and poles with a null complex part, i.e. no oscillation. Figure 8.11 shows the location of the system eigenvalues and Table 8.2 displays their values. The selected VSC controller gains are displayed in Table 8.3.

Table 8.3: VSC Control gains obtained from the MOGA optimisation.

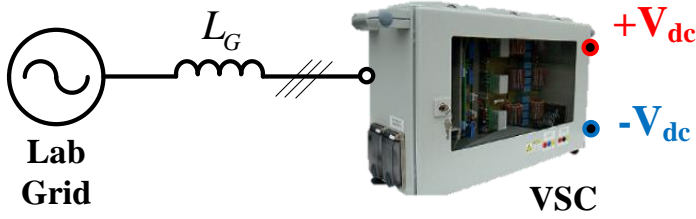
Controller	Proportional Gain	Unit	Integral Gain	Unit
ICC	$K_p = 7.7080$	[V/A]	$K_i = 6.3678$	[kV/As]
DVC	$K_p^W = 0.3723$	[mA/V ²]	$K_i^W = 48.6845$	[mA/V ² s]
RPC	$K_p^Q = 0$	[1/V]	$K_i^Q = 1.3371$	[1/Vs]
PLL	$K_p^{pll} = 6.3919$	[rad/Vs]	$K_i^{pll} = 3.3752$	[krad/Vs ²]

8.4 Small-Signal Model versus Experimental Results: VSC Model Validation

The results obtained from the MOGA optimisation were tested in a 5 kVA VSC in the laboratory of the Electrical Sustainable Energy Department of Delft University of Technology. Figure 8.12 displays a picture of the voltage-source converter and real-time controller used during the experiments, whereas the most important VSC component values are given in Table 8.1 [217].



(a) VSC cabinet, real-time controller, and host PC.

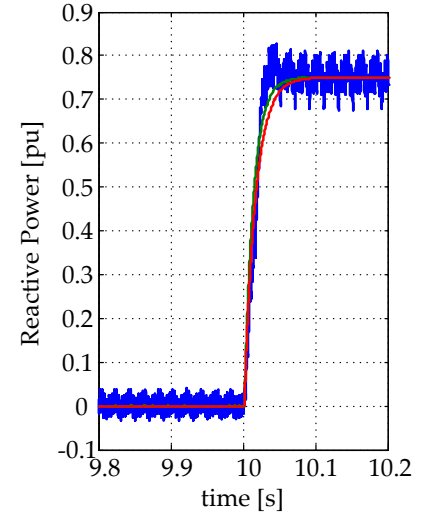
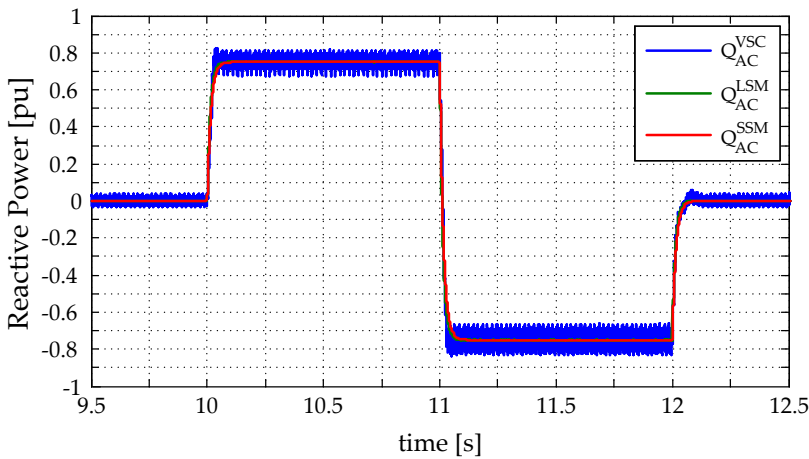


(b) VSC as a static synchronous compensator (STATCOM)

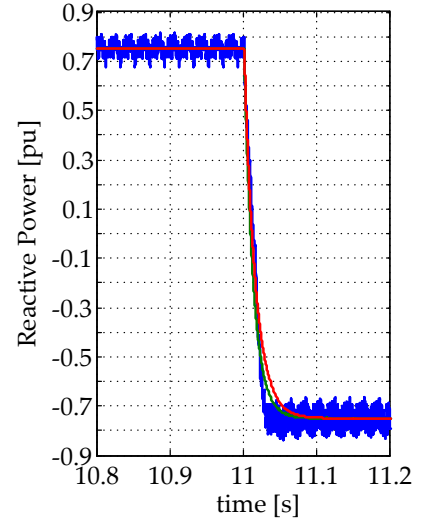
Figure 8.12: Laboratory setup for validating the VSC models [217].

For the validation of the small-signal model, the VSC was connected to the 380 V ac grid as a static synchronous compensator (STATCOM), as shown in Figure 8.12 (b). During the test, all the VSC controllers shown in Figure 8.3 were tested with the gains obtained from the MOGA control tuning optimisation (see Table 8.3).

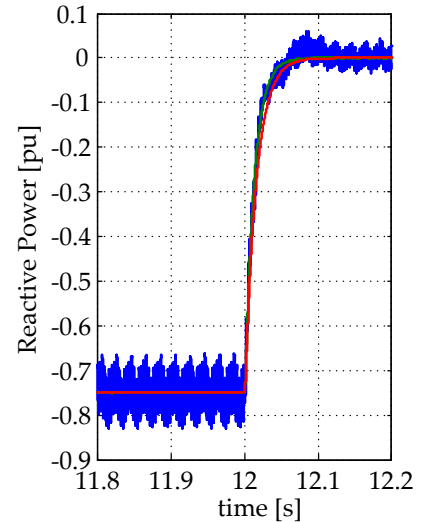
Figure 8.14 shows the VSC response to a step in the reactive power, after the controllers have been optimised by the MOGA. The results are shown for the 5 kVA VSC (blue), the non-linear model (green), and the small-signal model (red line). Figure 8.13 displays separately



(a) Step 1



(b) Step 2

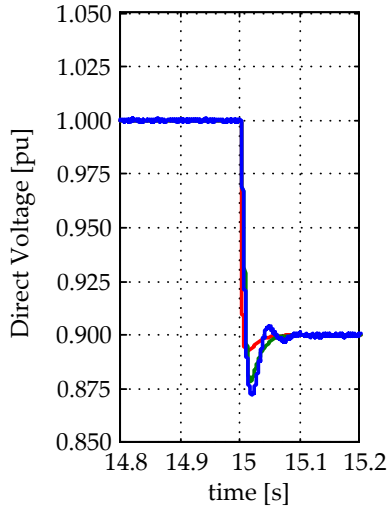


(c) Step 3

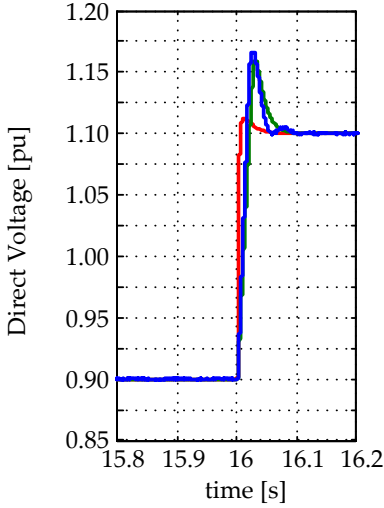
Figure 8.13: Steps in the VSC reactive power reference.

Figure 8.14: VSC reactive power during the model validation experiments.

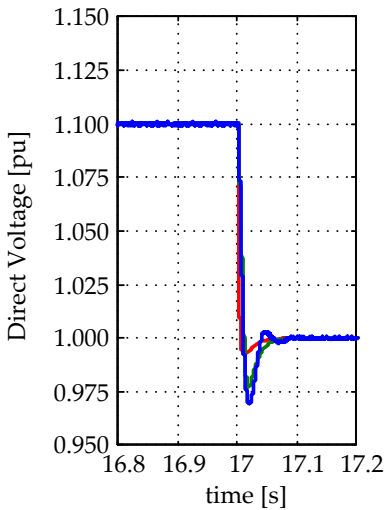
Figure 8.15: VSC direct voltage during the model validation experiments.



(a) Step 1

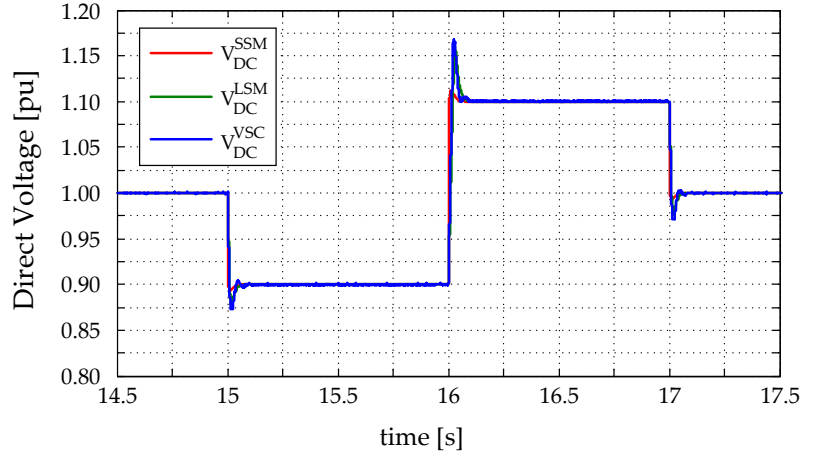


(b) Step 2



(c) Step 3

Figure 8.16: Steps in the VSC direct voltage reference.



each of the steps in the VSC reactive power.

The VSC reactive power is varied from 0 to 0.75 pu, i.e. 3750 VA, at $t = 10$ s. A positive value means the converter is absorbing reactive power from the lab ac grid.

Afterwards, the reactive power is varied from 0.75 to -0.75 pu and is then brought back to 0 pu at $t = 12$ s. Figure 8.14 and Figure 8.13 show the VSC reactive power response is very fast (less than 100 ms), and that both the non-linear and the small-signal models agree with the laboratory measurements.

Figure 8.15 shows the VSC response to a step in the direct voltage reference. Once again, the results are shown for the 5 kVA VSC (blue), the non-linear model (green), and the small-signal model (red line). Figure 8.12 displays separately each of the steps in the direct voltage.

For testing of the direct voltage controller, the VSC dc-side voltage reference was varied from 1 pu, i.e. 700 V, to 0.90 pu at $t = 15$ s. Afterwards, the direct voltage was varied again and, finally, brought back to 1 pu at $t = 17$ s. Figure 8.14 (a) and Figure 8.12 show the direct voltage response is as fast as the reactive power one.

The direct voltage results from the VSC large-signal model and the measurements taken in the 5 kVA VSC show a very good agreement. However, the small-signal model, due to disregarded non-linearities, does not correctly predict the small overshoots in the direct voltage.

8.5 Eigenvalue Sensitivity Analysis

Using the VSC state-matrix given in (B.1) in Appendix B.3, it is possible to show how the VSC eigenvalues locations, shown in Figure 8.11, vary with changes in the converter control gains, e.g. the ICC proportional or integral gain, or changes in the components values, such as the phase reactor or the dc-side capacitor.

The changes in the eigenvalues location with variation of the VSC components are presented in Figure 8.17 and Figure 8.18.

Hardware components have values which are not constant through their lifetime, therefore, it is important to assure that the complete

VSC system will maintain stability even if the components are not anymore at their rated values. Figure 8.17 shows the impact on the system eigenvalues location of variations of the dc-side capacitor and LCL-filter capacitor, whereas Figure 8.18 shows the impact for changes of the grid-side and converter-side inductances. From the eigenvalue sensitivity analysis of the VSC components it is possible to conclude the following:

- DC capacitor (C_{dc})⁷: The rated value of the dc-side capacitor is 500 μ F. A parametric variation of $\pm 20\%$ has very little impact on the grid-side current, filter voltage and outer controllers eigenvalues. However, the converter current, ICC, and PLL controllers eigenvalues will all start showing oscillations in their response. Nevertheless, the system remains stable for $\Delta C_{dc} = \pm 20\%$.
- LCL capacitor (C_f)⁸: The rated value of the dc-side capacitor is 20 μ F. A parametric variation of $\pm 50\%$ has very little impact on the outer controllers and PLL eigenvalues. However, as expected, it affects the grid current, filter voltage, converter current, and ICC eigenvalues. The converter current, and the ICC eigenvalues start displaying a non zero complex part. Nevertheless, the system remains stable for $\Delta C_f = \pm 50\%$.
- Grid-side inductance (L_g)⁹: The rated value of the grid-side inductance is 1.5 mH. As was the case with the LCL-filter capacitor, a parametric variation of $\pm 67\%$ on the grid inductance has little effects on the outer controllers and the PLL eigenvalues. However, the converter current, and ICC eigenvalues start showing oscillations in their response. Nevertheless, the system remains stable for $\Delta L_g = \pm 67\%$.
- Phase reactor (L_c)¹⁰: The rated value of the converter-side inductance – or phase reactor – is 1.5 mH. A parametric variation of L_g basically affects all the system eigenvalues. It specially affects the converter-side current, the ICC, and the PLL eigenvalues. Nevertheless, the system remains stable for $\Delta L_c = \pm 67\%$.

⁷ See Figure 8.17 (a)-(g).

⁸ See Figure 8.17 (h)-(n).

⁹ See Figure 8.18 (a)-(g).

¹⁰ See Figure 8.18 (h)-(n).

8.6 Conclusion

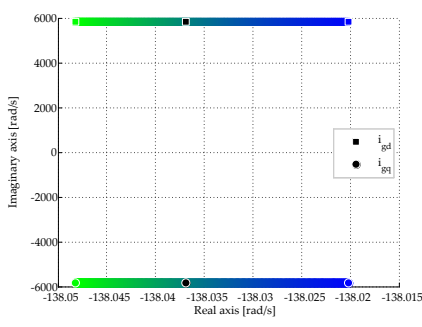
Results from the MTdc grid small-signal model have shown that its state-matrix always have a pole at the origin and, hence, the dc grids are always marginally stable systems. Therefore, to guarantee the stability of a MTdc network, feedback control of the system direct voltages is necessary, although not sufficient in case of contingencies, as shown in Chapter 7.

To model the voltage-source converter dynamics, and to select its controllers gains, a small-signal model is adequate. Moreover, a small-signal model of a power electronic converter is very valuable as it can be used to calculate the location of the converter eigenvalues. Then, with the aid of an optimisation algorithm, it is possible to obtain all the control gains which optimise the converter dynamic performance.

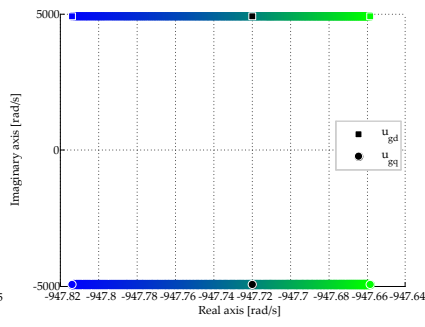
The laboratory test results of a VSC connected as a STATCOM have shown the converter dynamic response was accurate, i.e. without steady-state errors, and fast as step transients lasted for less than 100 ms.

Moreover, the experiments successfully validated the non-linear models of the VSC developed in Chapter 4, and the small-signal models of Chapter 8, as the simulation results displayed a very good agreement with the obtained measurements.

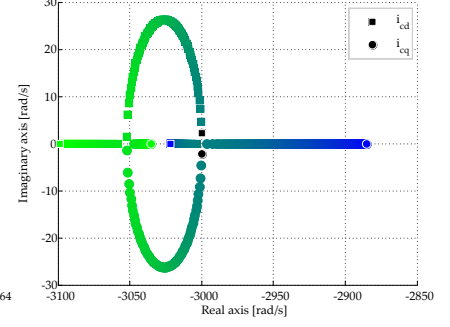
In the next chapter, the models and the obtained control gains are tested in a multi-terminal dc network to validate the distributed voltage control strategy developed earlier in Chapter 6.



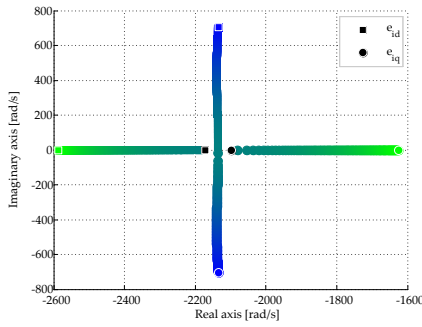
(a) Grid current eigenvalues



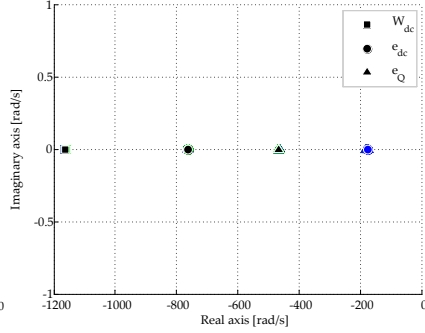
(b) Filter voltage eigenvalues



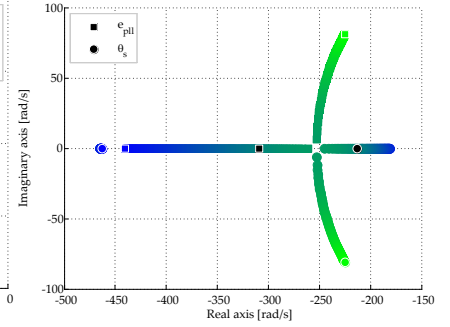
(c) Converter current eigenvalues



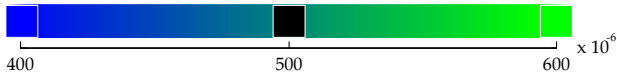
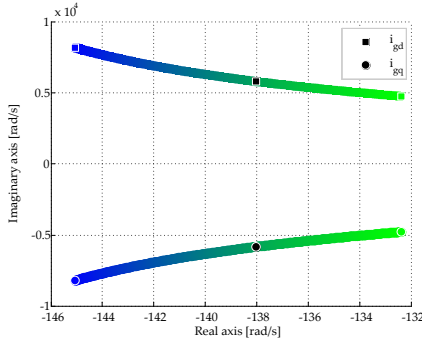
(d) ICC eigenvalues



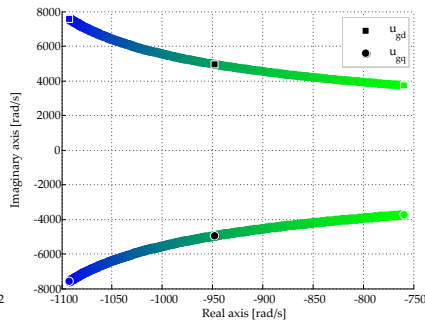
(e) Wdc and outer controllers eigenvalues



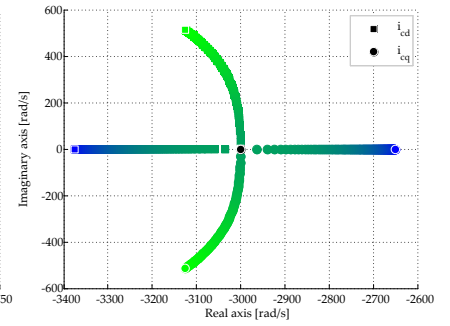
(f) PLL eigenvalues

(g) DC-side capacitor - C_{dc} 

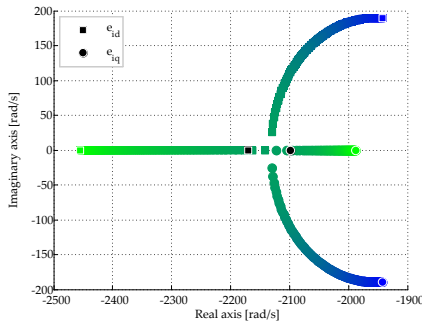
(h) Grid current eigenvalues



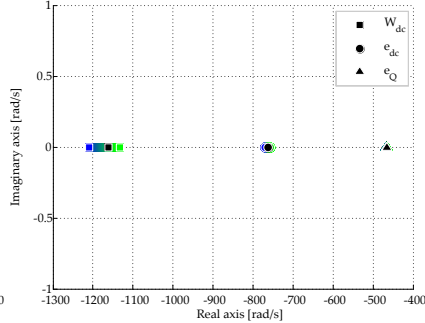
(i) Filter voltage eigenvalues



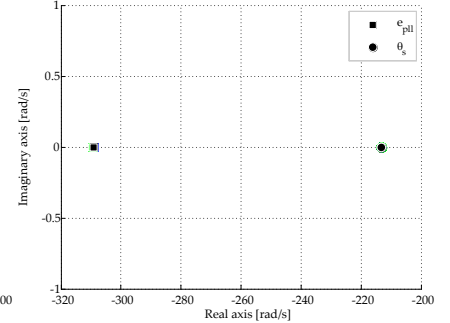
(j) Converter current eigenvalues



(k) ICC eigenvalues



(l) Wdc and outer controllers eigenvalues



(m) PLL eigenvalues

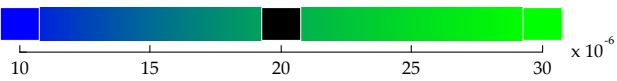
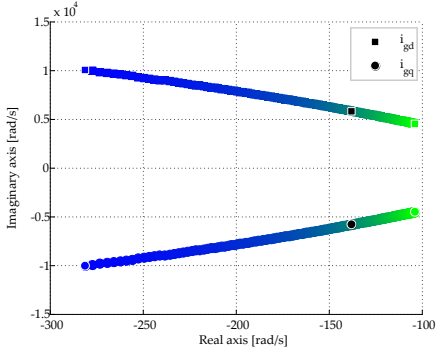
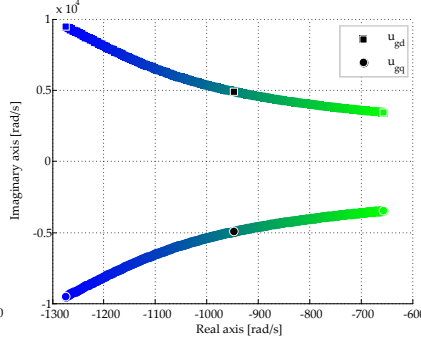
(n) LCL Filter capacitor - C_f

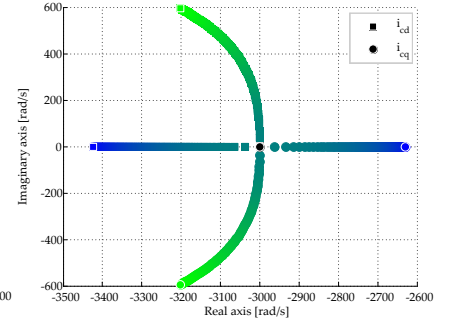
Figure 8.17: VSC eigenvalues as a function of the VSC LCL-filter capacitor and dc output capacitor.



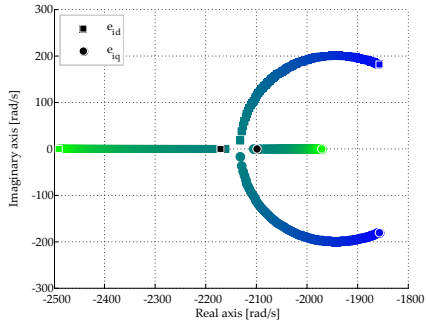
(a) Grid current eigenvalues



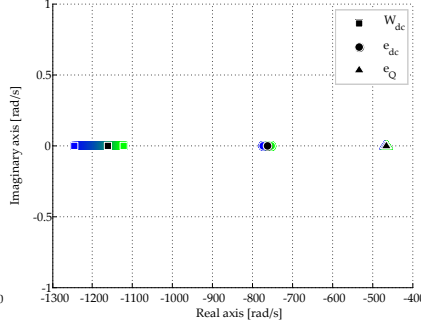
(b) Filter voltage eigenvalues



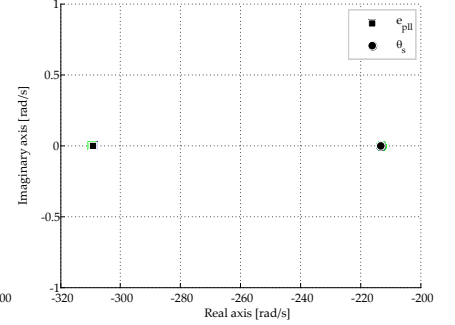
(c) Converter current eigenvalues



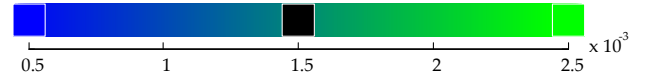
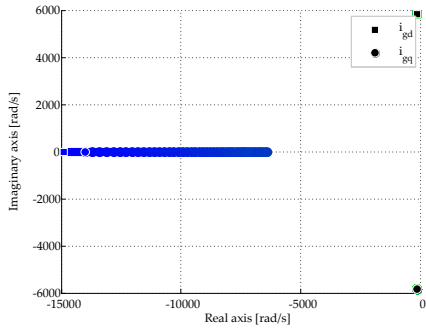
(d) ICC eigenvalues



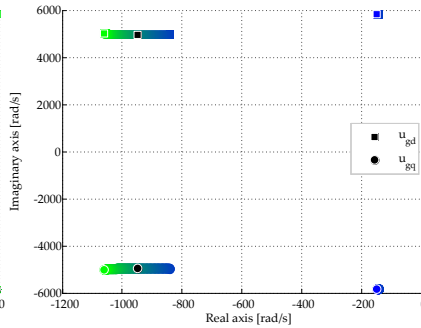
(e) Wdc and outer controllers eigenvalues



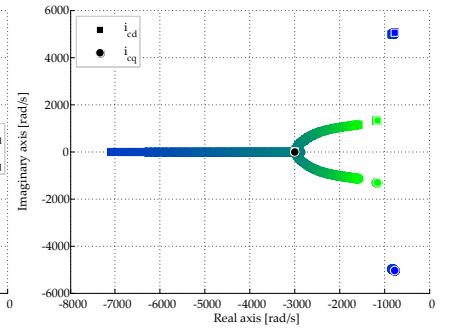
(f) PLL eigenvalues

(g) AC-side inductance - L_g 

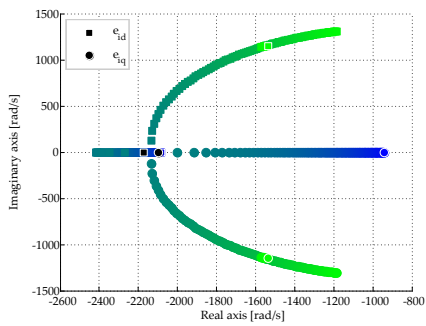
(h) Grid current eigenvalues



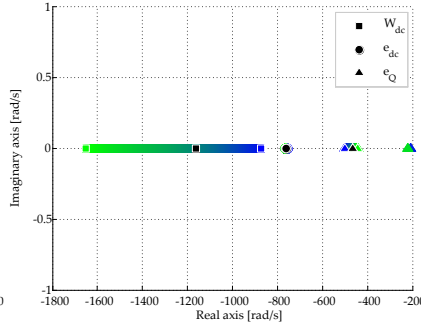
(i) Filter voltage eigenvalues



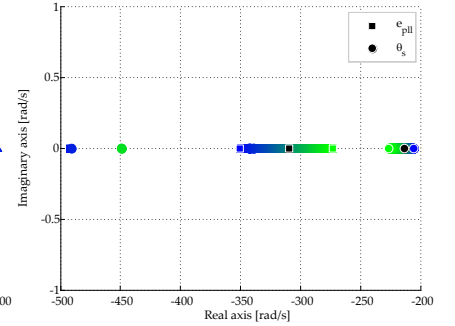
(j) Converter current eigenvalues



(k) ICC eigenvalues



(l) Wdc and outer controllers eigenvalues



(m) PLL eigenvalues

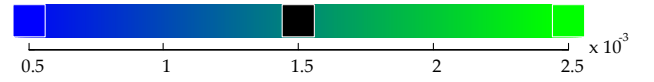
(n) VSC Phase Reactor - L_c

Figure 8.18: VSC eigenvalues as a function of the grid- and converter-side inductor.

Part V

Experimental Work & Conclusions

9

Laboratory Setup and Testing of a LV-MTdc System

[...] everything we know is only some kind of approximation, because we know that we do not know all the laws as yet. Therefore, things must be learned only to be unlearned again or, more likely, to be corrected. The test of all knowledge is experiment. Experiment is the sole judge of scientific "truth".

Richard Feynman - Lectures on Physics Volume I, Introduction

A high-voltage multi-terminal dc network, such as the North Sea Transnational Grid, will require multiple stakeholders, and will probably take decades before its construction is complete. Therefore, the chapter objective is to present a low-voltage MTdc system designed to reproduce, as much as possible, the behaviour of a HV-MTdc network. Based on the concepts developed in Chapter 2, the LV-MTdc network was built with a parallel-radial topology, by using three voltage-source converters with a symmetric monopolar configuration employing a metallic return.

The dynamic models developed in Chapter 4, and the small-signal stability analysis developed in Chapter 8, are used to control the converters in the experimental laboratory setup. The setup is then employed to validate the VSC and the MTdc network models, first in a back-to-back, and later in a MTdc network configuration. Afterwards, an impedance matching analysis is performed to try reproducing the frequency behaviour of a high-voltage MTdc network through the low voltage one. Finally, the LV-MTdc setup is employed to demonstrate the ability of the distributed voltage control strategy, developed in Chapter 6, in successfully controlling the power flow inside the LV-MTdc grid.

- 9.1. Experimental Laboratory Setup
- 9.2. Back-to-back Operation
- 9.3. MTdc Operation
- 9.4. Impedance Matching of a LV and a HV-MTdc Network
- 9.5. Distributed Voltage Control Strategy Validation
- 9.6. Conclusions

This chapter is based on the following publication:

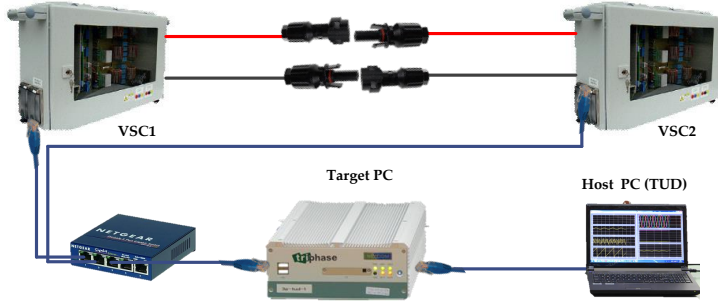
R. Teixeira Pinto, S. F. Rodrigues, P. Bauer, and J. Pierik, "Control and Operation of a Multi-terminal DC Network," in *8th International Power Electronics and Motion Control Conference (IPEMC)*, Melbourne, Australia, June 2013, pp. 1-8.

a Fluke 289 True RMS Multimeter, whereas the ac grid side current and voltage sensors were calibrated using a Nanovip Plus Power and Harmonic Analyser. Figure 9.3 shows the measured direct voltage before and after calibration and the used multimeter during calibration of the converters direct voltage sensor.

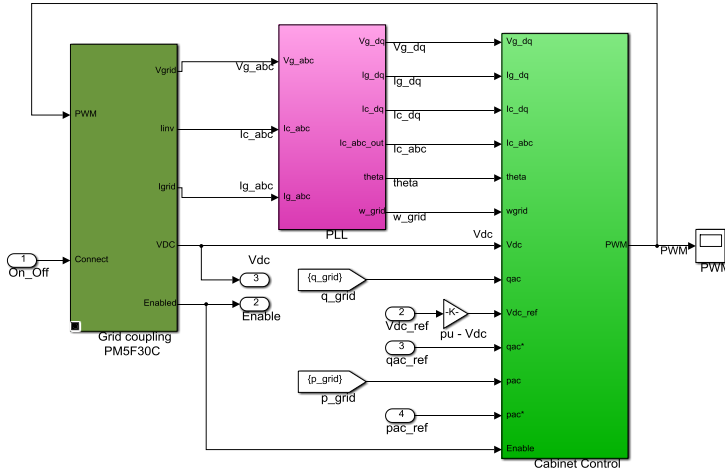
Real-Time Controller and Control Structure

All models to control the voltage-source converters in the low-voltage MTdc network were developed using Simulink. Figure 9.4 shows the control communication structure and the developed control blocks¹.

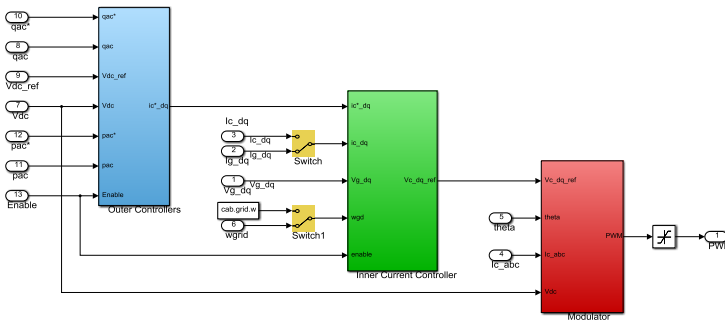
The converters operate with a controller (Target PC) which computes the control algorithms and transmits the PWM signals to the



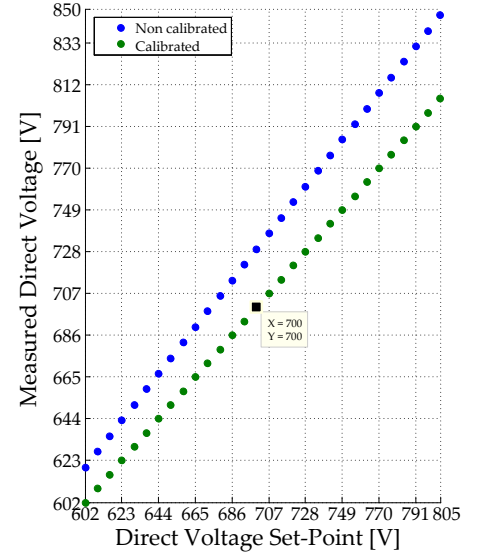
(a) Communication structure



(b) Voltage-Source Converter block



(c) Cabinet Control block



(a) Measured curves

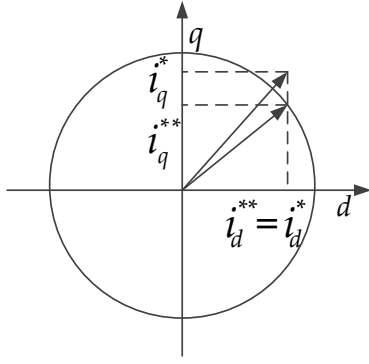


(b) Measurement device

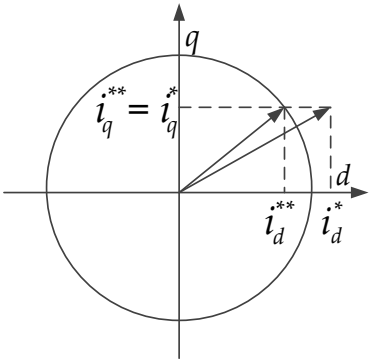
Figure 9.3: Direct voltage sensor calibration.

¹ After a model is developed using Simulink, the models are then compiled in C/C++ and uploaded to the Target PC, which will control the operation of the voltage-source converters in real time. The PWM signals are calculated using the developed model and sent to an ethernet switch which routes the signals to the respective converter. The converter switching frequency is 16 kHz, thus the control algorithm step time was selected as 62.5 μ s.

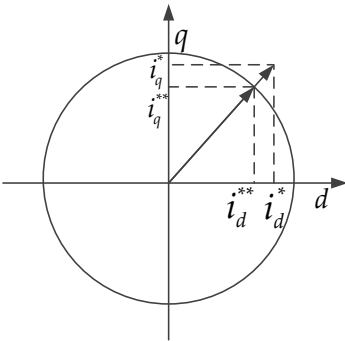
Figure 9.4: Control structure of the voltage-source converters.



(a) q-axis limiter



(b) d-axis limiter



(c) Proportional limiter

Figure 9.5: Control structure of the voltage-source converters.

² There are different ways to limit the converter current once it has surpassed its rated value, as shown in Figure 9.5: priority can be given to the d-axis current (reactive power channel), thus, limiting the q-axis one as in Figure 9.5 (a); the priority can be given to the q-axis current (active power channel), thus, limiting the d-axis one as in Figure 9.5 (b); or the priority can be to keep a constant power factor, thus, limiting both the d and q current components equally as in Figure 9.5 (c).

Figure 9.6: Outer controllers used in the experimental setup.

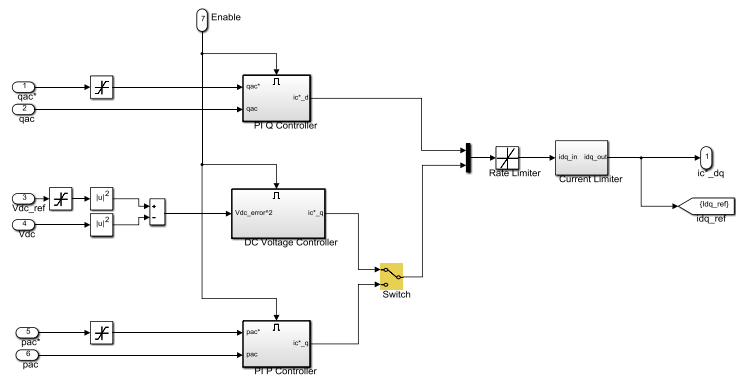
converters, in real-time, using an ethernet communication protocol. The converters then send back the current and voltage measurements to the Target PC which forwards the information to the Host PC, closing the hardware-in-the-loop control structure [217].

Once a control step is finished, the converter measurements – i.e. ac grid voltages and currents, converter currents and direct voltage – are made available in the Simulink model via the *Grid coupling PM5F30C* block. As shown in Figure 9.4 (b), the voltage-source converter block is composed of the measurements block, the phase-locked loop (PLL) block, and the converter control (*Cabinet Control*) block.

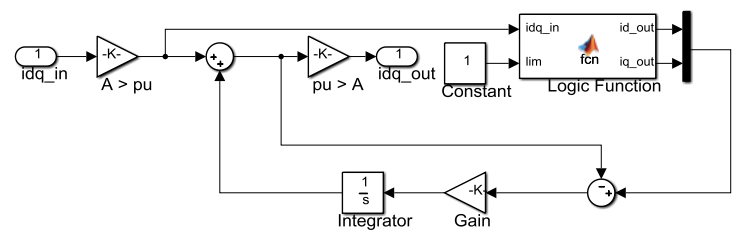
Since only two current sensors are available at the voltage-source converter and these were not calibrated, the inner-current controller works on the ac-grid side currents as shown in Figure 9.4 (c). Therefore, the grid-side voltage is used as a feed-forward term to the inner-current controller. This also means that the active power, and the reactive power, are controlled at the ac grid node and not at the inverter terminals. Figure 9.6 shows the outer controllers block and the current limiter block, which impedes the converter current module from surpassing its rated limit².

Space Vector PWM

The last block which needs to be defined is the modulator block. Except for the switched models used in Chapter 7 to study dc contingencies in a MTdc network, all models developed thus far were average models and, hence, did not included a PWM modulation block. The voltage-source converters in the low-voltage setup need



(a) Outer controllers block



(b) Current limiter block

the modulator block to send the switching signals to the IGBTs of the inverter bridge.

The Matlab implementation of the VSC modulator block shown in Figure 9.4 (c) is given in the code box below. An example of typical signals coming from the *Modulator* block is shown in Figure 9.7. The VSC reference voltage ($V_{c_dq_ref}$) is generated by the inner current controller in the dq reference frame.

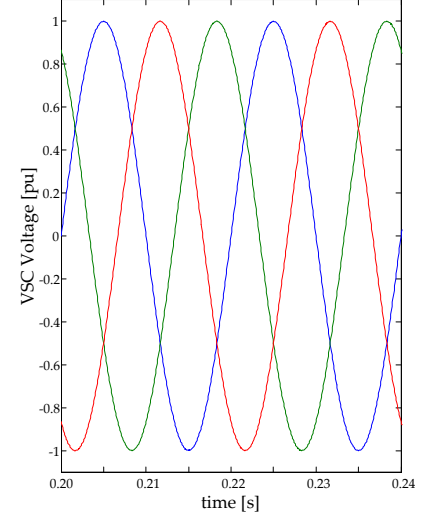
```

1 function PWM = ...
    Modulator(Vc_ref,Ic_abc,Vdc,Imax,SVM_on,DT_on,DT,Ts)
2
3 % Initialisation of PWM signals
4 PWM = zeros(3,1);
5
6 %Variables:
7 % Vc_ref: Converter reference voltage in abc frame from ICC
8 % Ic_abc: Converter currents in abc frame from measurements
9 % Vdc: measured direct voltage
10 % Imax: maximum allowable current
11 % SVM_on: 1 -> Space-Vector PWM, 0 -> Sinusoidal PWM
12 % DT_on: 1 -> Dead time on, 0 -> Dead time off
13 % DT: value of IGBT dead time
14 % Ts: control sampling time
15
16 % For all the three phases, i = 1,2,3 do
17 for i = 1:3
18
19     % if dead-time is enabled
20     if DT_on
21
22         % if the current module is above maximum
23         if abs(Ic_abc(i)) > Imax
24             Isign = abs(Ic_abc(i))/Ic_abc(i);
25             PWM(i) = 2*((Vc_ref(i) + (Vdc/2) + Isign * ...
26                 ((DT/Ts) * Vdc)) / Vdc) - 1;
27
28         else
29             PWM(i) = Vc_ref(i)/(Vdc/2);
30         end
31     else
32         PWM(i) = Vc_ref(i)/(Vdc/2);
33     end
34 end
35
36 % If Space-Vector modulation is on
37 if SVM_on
38     dmin = min(PWM);
39     dmax = max(PWM);
40     PWM = PWM - (dmax + dmin)/2;
41 end

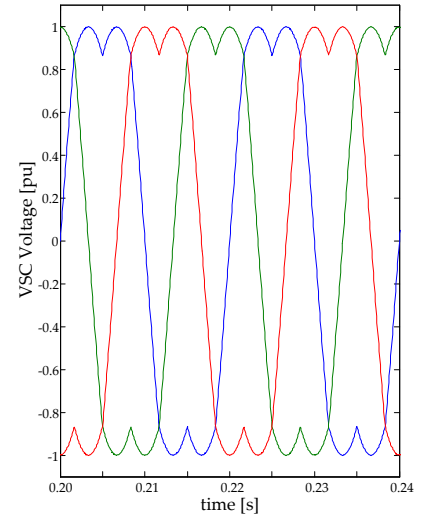
```

The reference voltages are then passed through an inverse Park transformation to generate signals in the abc reference frame (V_{c_ref}), displayed in Figure 9.7 (a). In case the space-vector modulation technique is enabled, the *Modulator* block then transforms the converters reference signal into the signal displayed in Figure 9.7 (b).

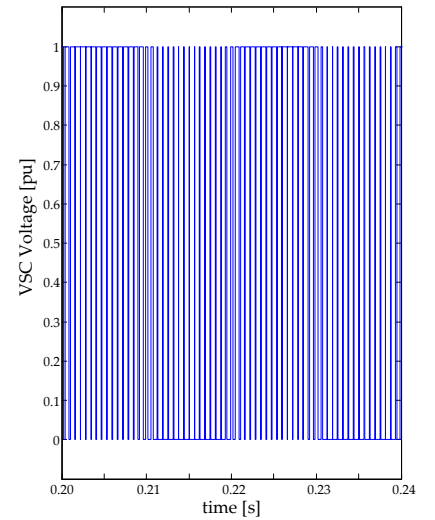
The space-vector modulation advantage is that, by inserting a third-harmonic in the original signal, the value of the fundamental harmonic can be increased by $2/\sqrt{3} \approx 1.155$ pu, which is 15.5% higher than what it could be achieved with sinusoidal PWM modulation before the VSC goes into overmodulation operation.



(a) VSC reference voltage



(b) Space vector modulation signal



(c) SVPWM signal phase A

Figure 9.7: Example of signals coming from the *Modulator* block.

The last signal in Figure 9.7 is the result from the comparison of the space-vector modulation signal with the triangular carrier at the converter switching frequency of 16 kHz. The signal shown in Figure 9.7 (c) is for phase A only, but two similar signals are also generated for the other converter phases. After these SVPWM signals are sent to the VSC, the control algorithm is updated and a new set of SVPWM signals is generated. This control loop lasts until the converter operation is halted.

9.2 Back-to-back Operation

In this section, the VSC models and controls gains obtained from the multi-objective genetic algorithm in Chapter 8 are tested in a back-to-back topology before the converters are connected in a MTdc network. The converters, VSC1 and VSC2, are connect to each other via 4 mm² LVdc cables, which is 10 m long. Table 9.1 gives the rated values of the VSC parameters, whereas the experimental setup is displayed in Figure 9.8.

In this experiment, the VSC1 is controlling the dc-link voltage at 700 V (1 pu) using a PI controller, whereas the VSC2 is controlling the exchanged active power through the dc link, also with a PI controller.

A series of tests are performed to validate the following VSC controllers: reactive power controller; the direct voltage controller; and the active power controller. Although the reactive power and the direct voltage controllers were already validated in Chapter 8, when VSC1 was connected to the ac network as a STATCOM, these controllers are again here tested for analysis completeness.

The results from the experiments with a back-to-back topology are shown in Figure 9.9, and in more detail in Figure 9.10. The results show, for both converters, the reactive power at the ac-grid side, the

Figure 9.8: Experimental setup used to test the VSC operation in a back-to-back topology.

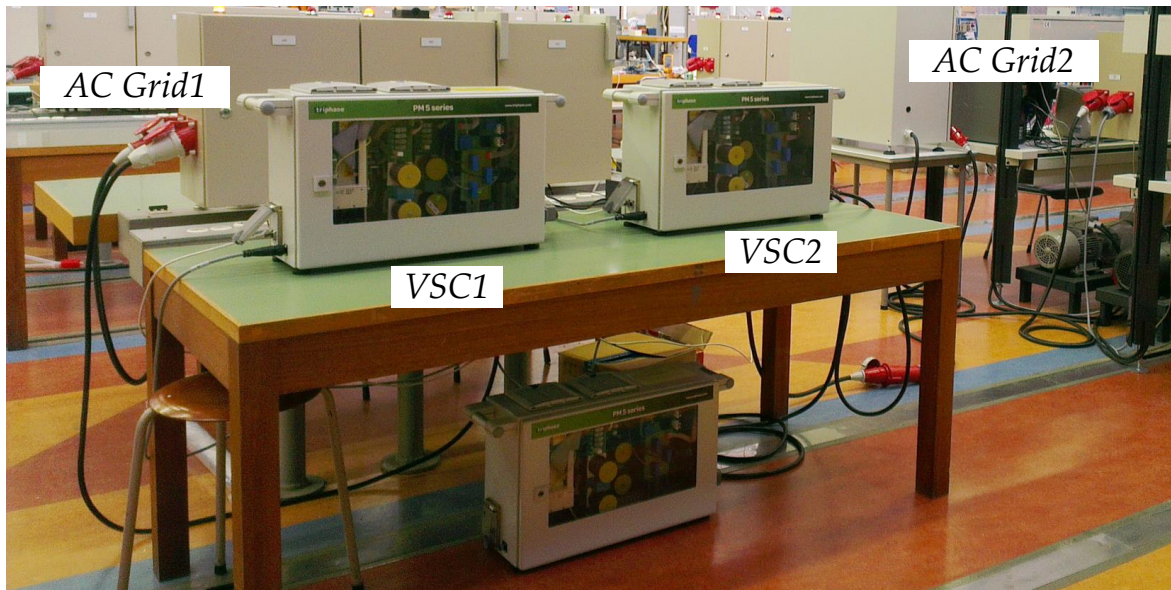
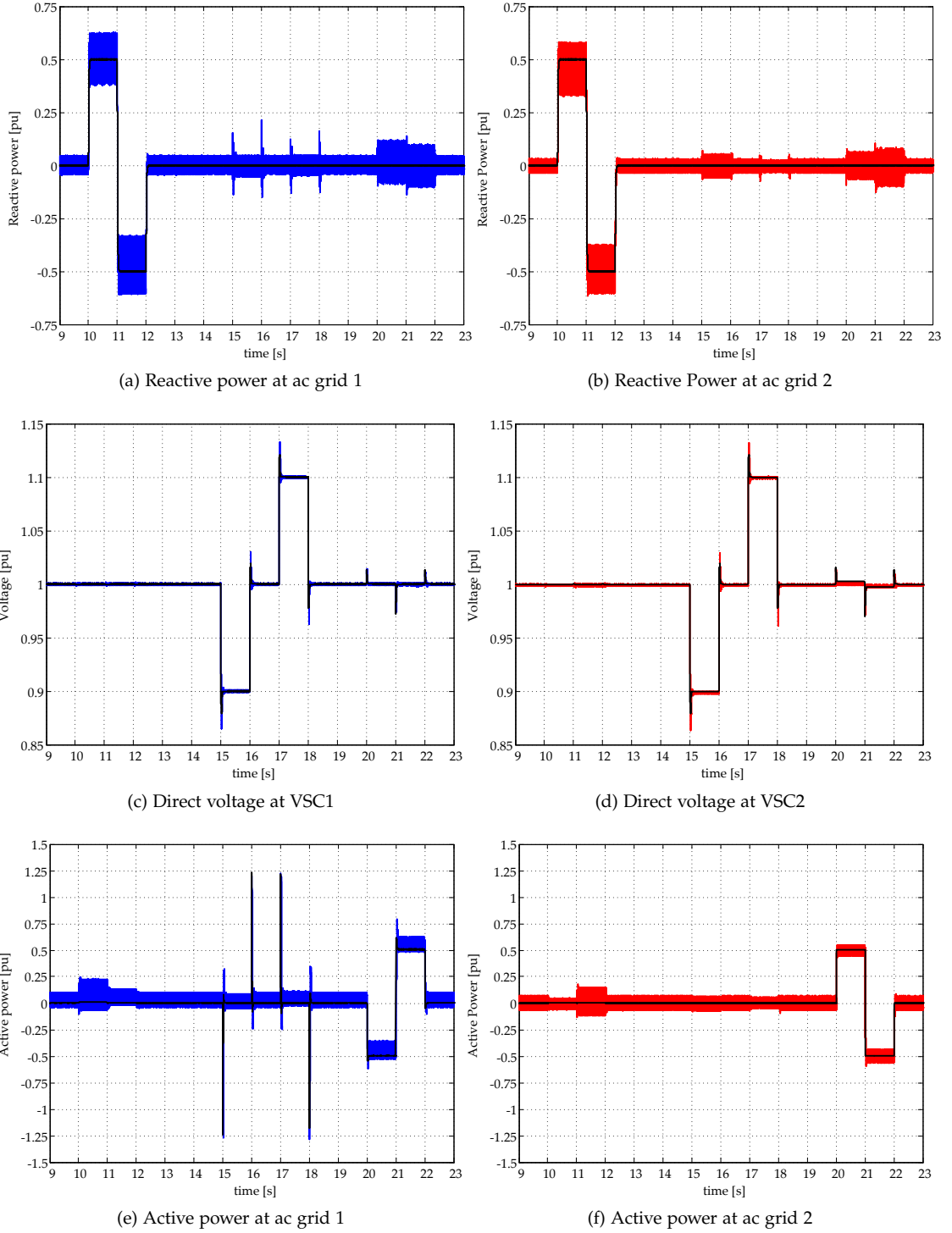


Figure 9.9: Results from the back-to-back configuration experiments.



direct voltage at the converter output, and the active power at the ac-grid side. In both Figure 9.9 and Figure 9.10, the blue curves correspond to measurements taken from VSC1, whereas the red lines are the measurements from VSC2, and the black lines correspond to the results from the VSC large-signal model developed in Chapter 4.

First, at $t = 10$ s, both converters reactive power references are changed step-wise to 0.5 pu (2.5 kVar). One second later, the reactive power flow is inverted to -0.5 pu, and then brought to zero at $t =$

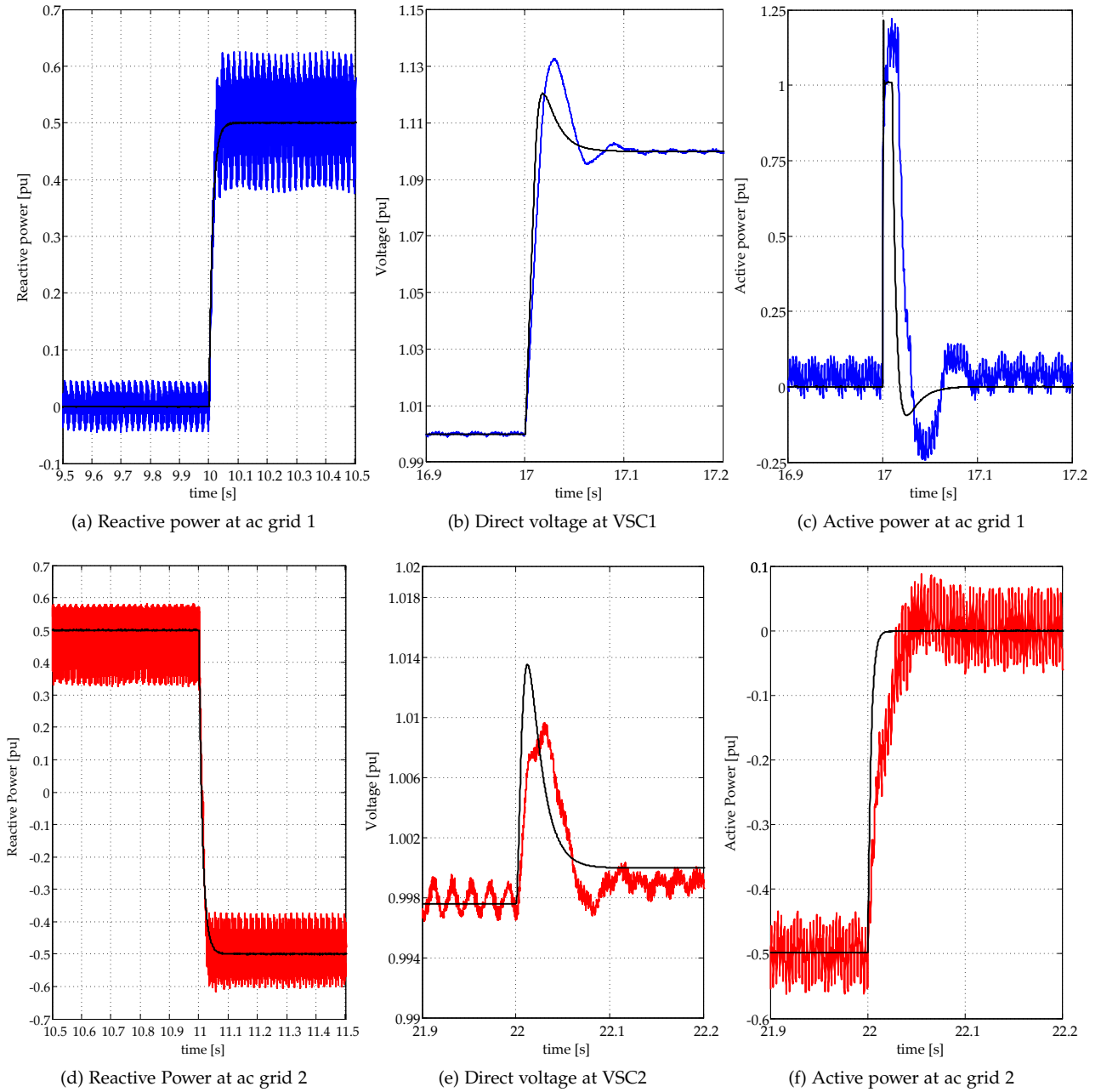


Figure 9.10: Zoom-in from the results during the back-to-back experiments.

12 s. The reactive power controller is accurate and fast, i.e. there are no steady-state errors and the set-points are reached within less than a 100 ms.

Additionally, the reactive power controller does not perturb the direct voltage controller of VSC1 or the active power controller of VSC2, except for the slight higher losses observed from $t = 10$ to $t = 11$ s in VSC1, and $t = 11$ to $t = 12$ s in VSC2.

The direct voltage set-point of VSC1 is changed from 1 pu (700 V) to 0.9 pu at $t = 15$ s. The dc-link voltage is brought back to 1.0 pu 1 s later, increased to 1.1 pu at $t = 17$ s, and finally restored to 1 pu at $t = 18$ s. Since the VSC1 is controlling the dc-link voltage, some

active power pulses are seen on its grid side, but no disturbance is found in the VSC2 active power. The active power pulses are needed to rapidly change the voltage of the dc bus, which reaches the new operating points within a 100 ms with overshoots of less than 5%.

Lastly, the active power controller of VSC2 was tested. The active power set-point of VSC2 is varied to 0.5 pu (2.5 kW) at $t = 20$ s. The power flow is reversed to -0.5 pu after 1 s, and stopped at $t = 22$ s. The VSC2 active power response is fast and capable of inverting the power flow in less than 50 ms. When the VSC2 active power varies, the VSC1 active power overshoots a little to reestablish the dc-link voltage to 1 pu. The dc-link voltage shows small ($\leq 3\%$) transients when the converters change their active power exchange.

It can be seen from Figure 9.9, and specially from Figure 9.10, that the direct voltage, the active power, and the reactive power measurements all agree with the simulation results obtained from the developed models within small error margins.

9.3 MTdc Operation

After operating two voltage-source converters in back-to-back, a third terminal was added to the low-voltage setup forming a parallel-radial multi-terminal dc network. To improve safety, all equipments and cables were insulated, and at the cable joints Multi-Contact MC4 connectors, rated for 20 A currents and voltages up to 1000 V, were used. Figure 9.11 displays the common connection point for the MTdc network negative pole³.

Figure 9.12 displays the multi-terminal dc network layout. Once more, the three converters were connected via 4 mm² LVdc cables, whose characteristics are presented in Table 9.3, and discussed in detail in Section 9.4.

In this first MTdc network experiment, the VSC1 controls its direct voltage at 1 pu, or 700 V, while VSC2 and VSC3 are controlling their active power at the ac grid side. The MTdc network start-up

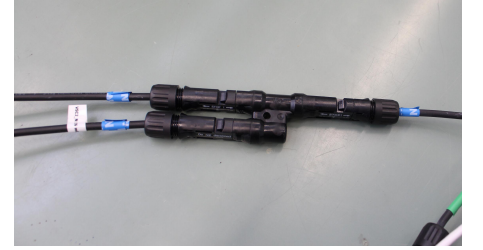


Figure 9.11: Cable joint at the MTdc network negative pole.

³ The voltage-source converters employed in the low-voltage MTdc network setup are two-level converters whose mid-point of the dc bus is connected via a filter to the converter neutral at the grid side (see Figure 9.2). Therefore, the MTdc network is formed by a symmetric monopole topology and its rated voltage is 700 V or ± 350 V.

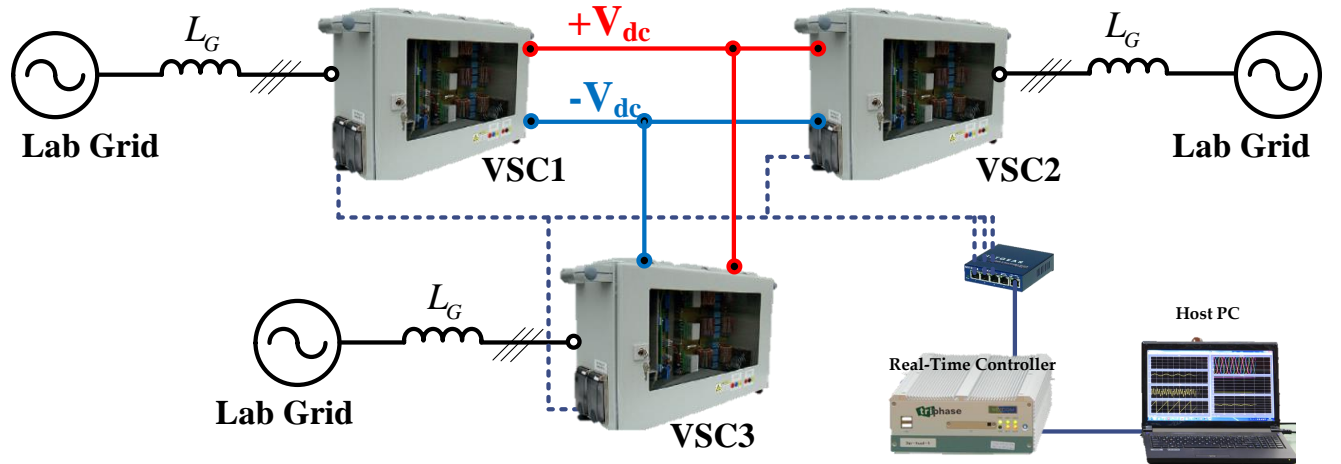


Figure 9.12: Layout of the experimental low-voltage MTdc network to be studied.

procedure is explained next.

Start-up Procedure

Upon system initialisation, the converters ac switches and the bypass switches are all opened. Nevertheless, measurements of the grid voltage are available to the Target PC, and the phase-locked loop controllers can start immediately operating. Figure 9.14 shows the ac grid voltage for all three converters in the (dq) reference frame. It can be seen from the graphics, that after circa 10 network cycles (≈ 200 ms), the PLL has already finished locking the converter (dq) reference frame to the ac network voltage phasor. The angular frequency from the VSC1 PLL during the start-up procedure is displayed in Figure 9.13.

Since VSC1 is the converter which will be controlling the MTdc network voltage, it is the first converter to be activated. The start-up of a VSC is made in three different steps:

1. Firstly, the ac switch is closed while the bypass switch is left open and the converters IGBTs are blocked;
2. secondly, the bypass switch is closed while the converter IGBTs are still blocked and;
3. thirdly, the converter IGBTs are unblocked and normal operation begins.

During the experiments, the ac switch was closed at operation time $t \approx 4$ s, and the bypass switch and the converter IGBTs were unblocked half a second later, at operation time $t \approx 4.5$ s.

Figure 9.14: Voltages at the grid side in the dq reference frame.

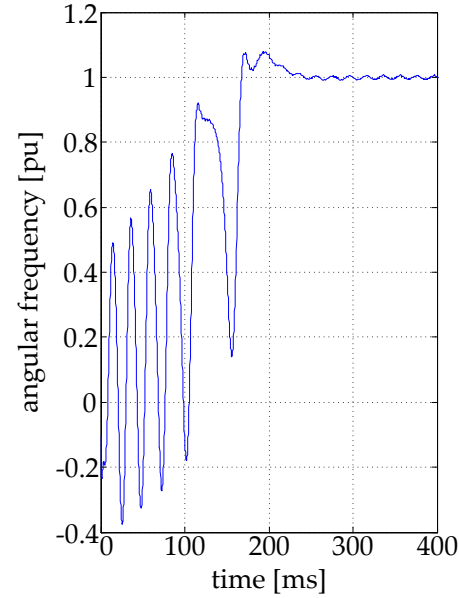
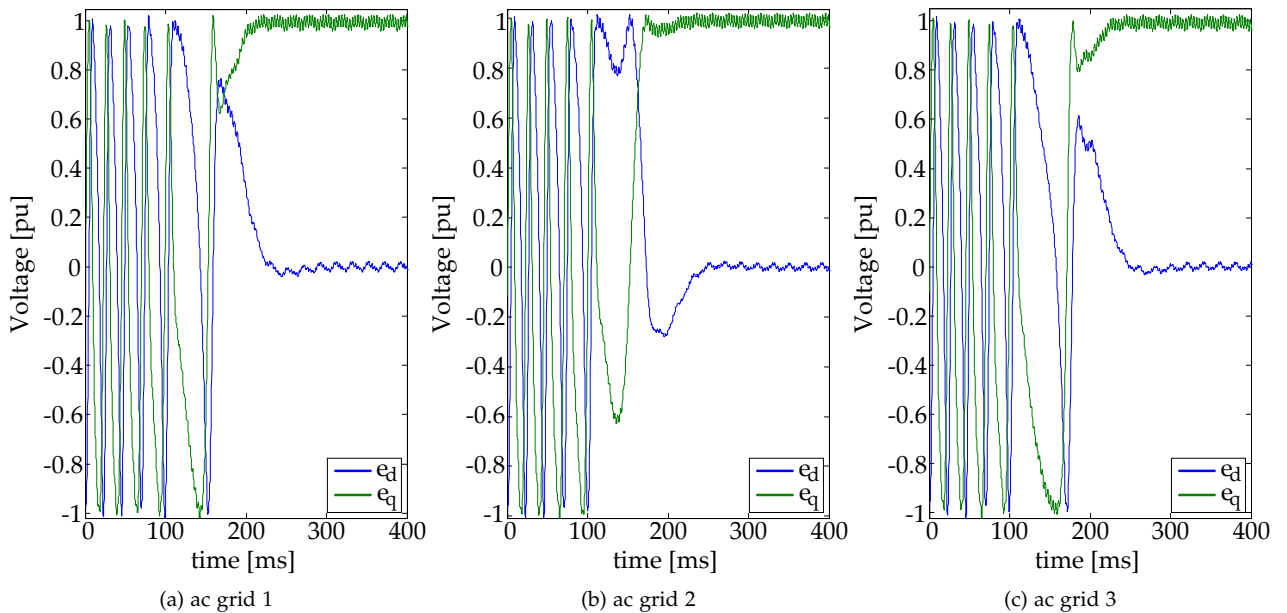


Figure 9.13: Angular frequency of VSC1 PLL during start-up procedure.



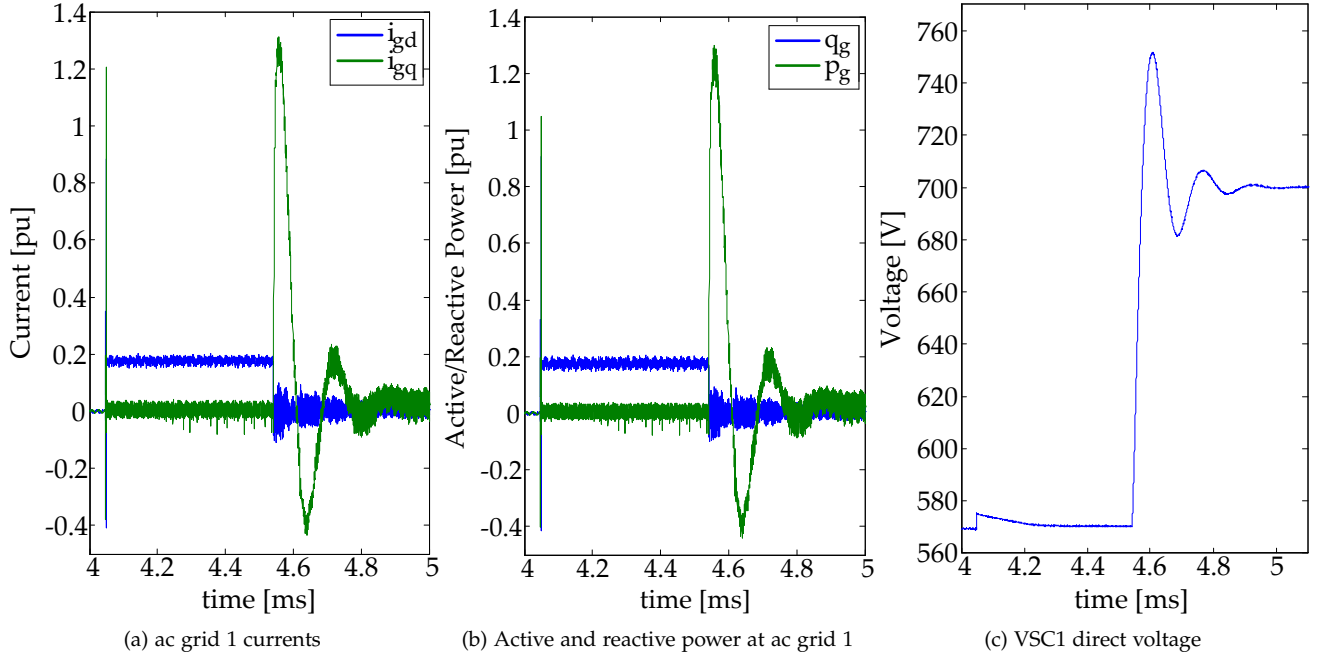


Figure 9.15: VSC1 currents, power and direct voltage during start-up procedure.

Figure 9.15 displays the measured grid currents at the ac grid side for VSC1, and the converter direct voltage. It also displays the reactive and active power at the grid side⁴.

After the ac switch is closed, there is a large current spike which goes into charging the LCL filters. The active part of the current spike also increases a little the converter dc bus voltage. During operation time, $4 \leq t \leq 4.5$ s, the grid active current, i_{gd}^g , is practically zero, only feeding losses in the in-rush resistor and LCL filter. On the other hand, the grid-side reactive current, i_{gq}^g , is approximately 0.2 pu, since:

$$Q_f = 3\omega C_f U_f^2 \approx 100\pi \cdot 20 \times 10^{-6} \cdot 400^2 \approx 1 \text{ kVar} = 0.2 \text{ pu} \quad (9.1)$$

During that same period, the converter direct voltage value is approximately:

$$V_{dc} = \sqrt{2} \cdot E_L = \sqrt{2} \cdot 400 \approx 566 \text{ V} \quad (9.2)$$

Finally, at operation time $t \approx 4.5$ s, the bypass switch is closed and the converters IGBTs are unblocked so that VSC1 can start normal operation. Immediately after the IGBTs are unblocked, the VSC controls absorb active current to increase the converter dc bus voltage from 566 V to the its nominal value of 700 V. During the transients, which lasted for around 500 ms, the active current peaked at 1.3 pu, and the direct voltage peaked at circa 752 V (or 1.074 pu)⁵.

After VSC1 has finished bringing the MTdc network voltage to 1.0 pu, the other two converters can be unblocked, and the system is ready for normal operation.

⁴ It is interesting noting the similarities between the converter currents, and its reactive and active power. Due to the PLL action and the vector control implemented in the (dq) rotating frame, the two graphics are almost exactly the same. In per unit, the d-axis current is almost equivalent to the converter reactive power, whereas the q-axis current is almost equivalent to the converter active power.

⁵ The start-up transients can drawn less current if the direct voltage set-point is not changed stepwise from 0.8 pu to 1.0 pu when the converter IGBTs are unblocked. For instance, the converter direct voltage could have been brought to 1.0 pu using a ramp reference signal. In that case, the start-up would have taken more time, but the transient current peak would have been lower.

Table 9.2: Active power reference of VSC2 and VSC3 during the normal operation experiments.

Time	VSC2	VSC3	VSC1 ⁺
16.7	0.25	0.00	-0.25
23.7	0.25	0.25	-0.50
29.7	0.50	0.25	-0.75
35.0	0.50	0.30	-0.80
43.2	0.00	0.30	-0.30
49.2	-0.30	0.30	0.00
59.0	-0.75	0.30	0.45
64.8	-0.75	0.50	0.25
72.6	-0.75	0.75	0.00
83.3	-0.50	0.75	-0.25
93.3	-0.25	0.75	-0.50
98.1	-0.25	0.50	-0.25
104.1	-0.25	0.25	0.00
107.5	0.00	0.25	-0.25
111.5	0.00	0.00	0.00
117.3	off	0.00	0.00
121.0	off	off	0.00
124.1	off	off	off

+ the VSC1 power indicated in Table 9.2 is indicative only and disregards all losses inside the low-voltage MTdc network setup.

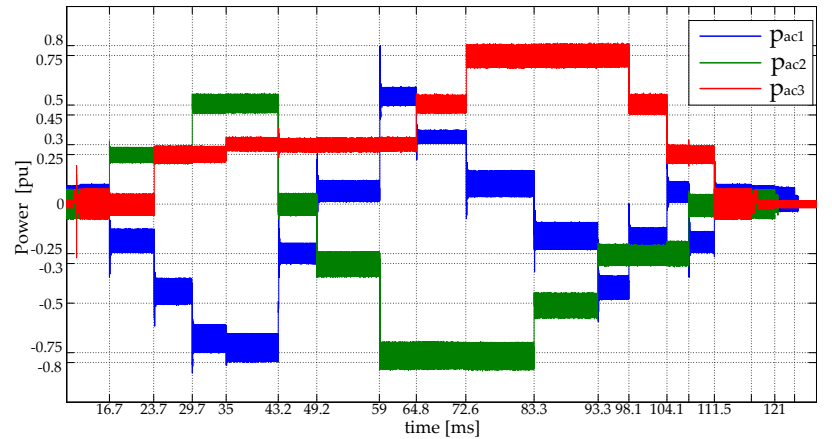
Normal Operation

During the experiments, the active power of converters VSC2 and VSC3 were varied manually from the Host PC, during circa 2 minutes, according to the values shown in Table 9.2. According to (5.1), special attention was made such that the active power sum from VSC2 and VSC3 ($P_{ac2} + P_{ac3}$), was never above 1 pu (or 5 kW), since only VSC1 was controlling the multi-terminal dc network voltage.

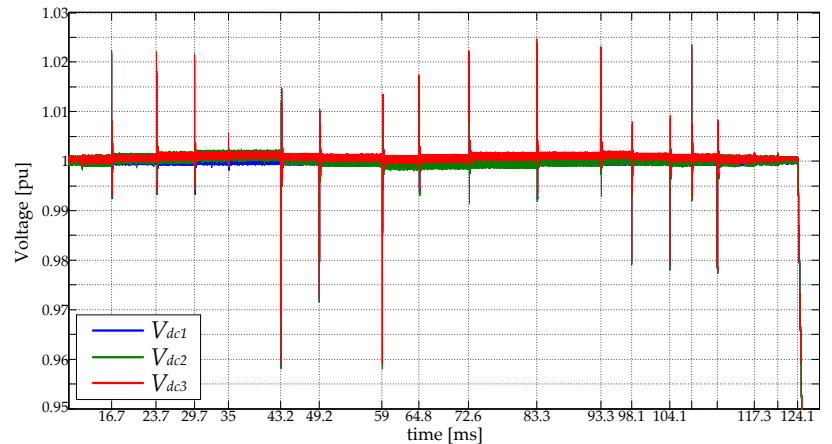
The active power at the grid side of all three converters during the experiments is displayed in Figure 9.16 (a), whereas the direct voltage at the three MTdc network nodes is given in Figure 9.16 (b). During the complete experiment duration, all three converters controlled the reactive power at the ac grid side to zero.

As shown in the results, whenever the active power of VSC2 or VSC3 was varied, the VSC1 would adjust its power reference so as to balance the power in the multi-terminal dc network, keeping the direct voltage controlled at 1 pu (or 700 V). The small overshoot in VSC1 active power is a result of the direct voltage PI controller bringing the MTdc network voltage back to 1 pu.

Whenever net active power was being injected into the MTdc network, e.g. at operation time, $t = 23.7$ s or $t = 29.7$ s, the MTdc net-



(a) Active power at grid side



(b) Direct voltage

Figure 9.16: Grid side currents and direct voltages of all three converters during normal operation.

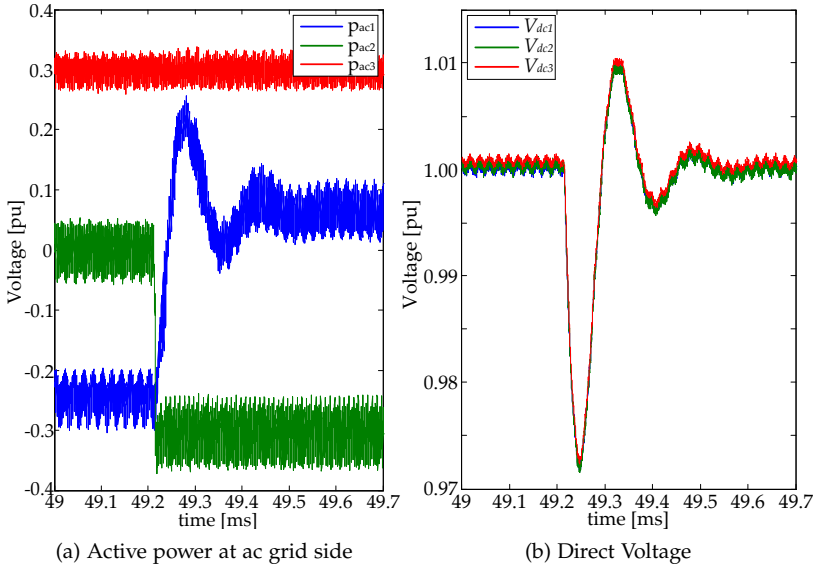


Figure 9.17: MTdc network transient response during a change in the operating point.

work voltage first increases and then returns to 1 pu. Whenever net power is being withdrawn from the MTdc network, e.g. at $t = 43.2$ s or $t = 49.2$ s, the dc grid voltage first drops and is then restored to its nominal value.

A closeup of the MTdc network active power and direct voltage transient responses, during a change in the operating point, is displayed in Figure 9.17. At operation time, $t = 49.2$ s, the VSC3 changes its active power set-point from 0 to -0.3 pu in less than 50 ms.

To counteract the change in the active power of VSC3, the VSC1 changes its active power value so as to balance the power in the MTdc network and, within 400 ms (see Figure 9.17 (b)), the system direct voltage is restored at 1 pu.

Since the only converter controlling the direct voltage is VSC1, it is responsible for the providing the system losses to balance the dc network. The average total losses in the system – including conduction and switching losses in all three converters, losses in the ac and dc cables, and in the LCL filters – can be estimated from the measurements as:

$$\begin{cases} \bar{p}_{losses}(k) = \sum_{j=1}^3 \bar{p}_{acj}^{vsc}(k) \\ \bar{p}_{acj}^{vsc}(k) = \frac{1}{T} \int_{T \cdot k}^{T \cdot (k+1)} p_{acj}^{vsc}(t) dt \end{cases} \quad (9.3)$$

where;

$\bar{p}_{losses}(k)$ is the average MTdc network losses in period k [W];

$\bar{p}_{acj}^{vsc}(k)$ is the average active power at ac grid side of converter j [W];

k is the averaged period number;

T is the averaging period [s] and;

$p_{acj}^{vsc}(t)$ is the measured instantaneous active power at ac grid side of converter j [W].

⁶ In that case, the total number of averaged periods is $t_{end}/T = 124/1 = 124$; where t_{end} is the total experiment time.

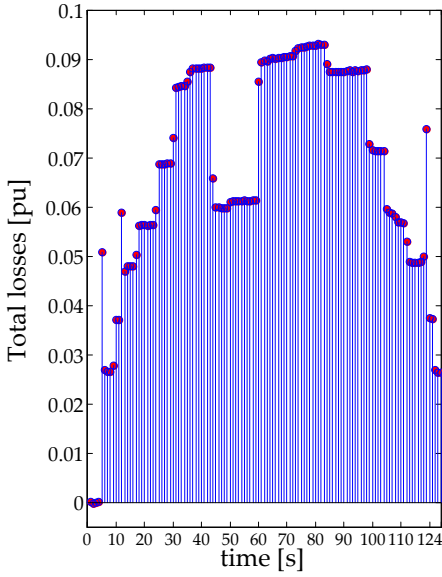


Figure 9.18: Averaged total losses in the MTdc network.

Table 9.3: Comparison between the parameters of the LVdc (measured) and HVdc cables (typical).

Cable	LVdc	HVdc
Voltage [kV]	1.2	± 320
Current [A]	56	1791
Area [mm ²]	4	1200
r_{dc} [m Ω /m]	10.093	0.0151
l_{dc} [μ H/m]	8.735	0.190
c_c [pF/m]	60.8	220

Figure 9.19: Open-circuit and short-circuit impedance of a 5-m LVdc cable (green line) and a 50-km HVdc cable (blue line) in the frequency domain before and after impedance matching.

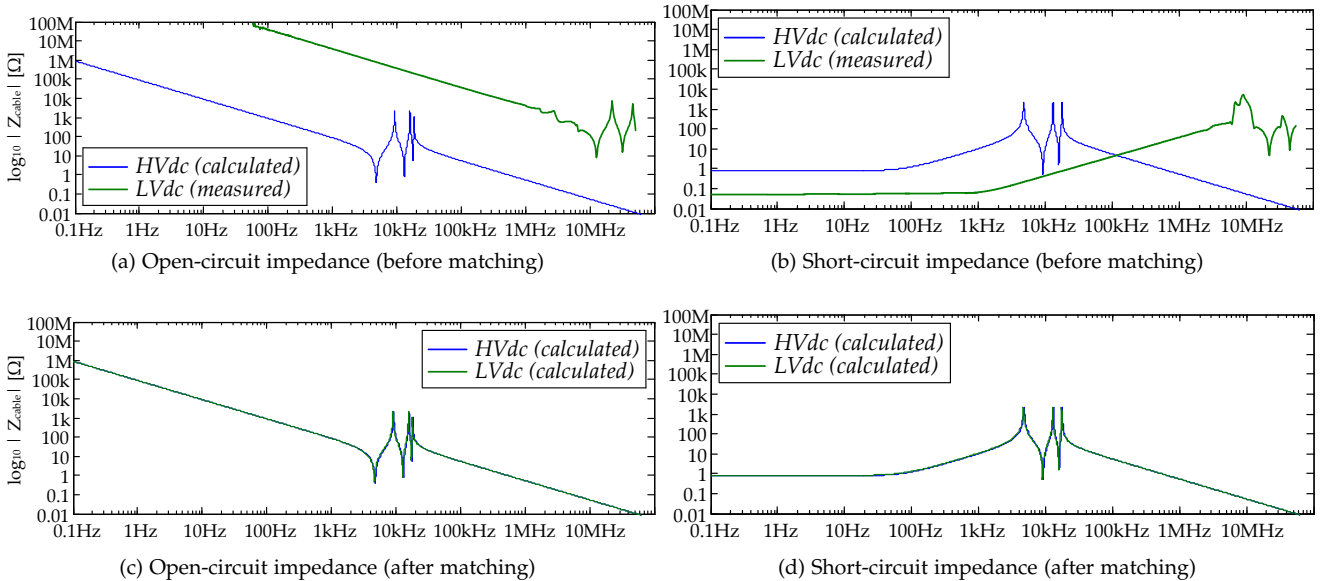


Figure 9.18 shows the MTdc network total losses for an averaging period of $T = 1$ s⁶. Hence, each stem in Figure 9.18 displays the average of the system losses during one second. In average, the total system losses was always lower than circa 0.10 pu and it was higher, in absolute terms, when either VSC2 or VSC3 were withdrawing more power from the MTdc network.

The network losses are low, less than 0.10 pu, because the converters were connected to each other via LVdc cables, 5 meter long, whose resistance is circa 10 m Ω per meter. This is the same reason why the direct voltage values of all three terminals in the MTdc network are very close to each other as voltage drops in the MTdc network are very small. Therefore, before the low-voltage dc setup can be used to emulate the response of high-voltage dc networks, an impedance matching between the two systems must be performed.

9.4 Impedance Matching of a LV and a HV-MTdc Network

The experimental low-voltage MTdc network setup built in the laboratory uses three identical voltage-source converters as the ones shown in Figure 9.1. The converters were connected in a parallel-radial topology by means of LVdc cables.

Table 9.3 displays the measured parameters of the 4 mm² LVdc cable used in the laboratory, and a comparison with typical parameters from a VSC-HVdc cable. The LVdc cable parameters were measured using an impedance analyser. Figure 9.19 shows a comparison between the open-circuit impedance, and short-circuit impedance, of both the LVdc and HVdc cables in the frequency domain.

In HVac systems there are unexpected voltage rises due to resonances between the transmission line impedance, transformers, and capacitors and reactor banks used to compensate the ac line power factor [78]. In comparison with HVac, in HVdc systems there are

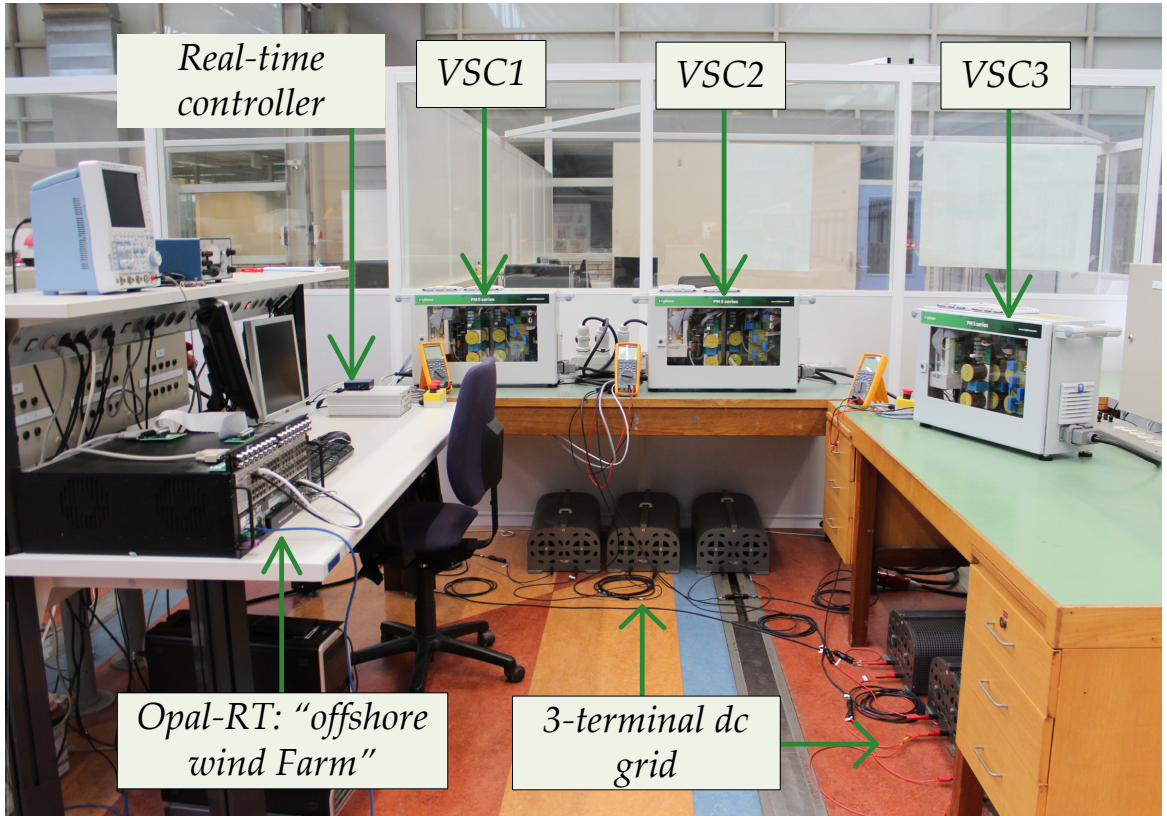
less voltage surge problems due to resonances. Since cables used for HVdc transmission have resonance peaks in high-frequencies, the harmonic content on the dc side can be easily mitigated via low-pass filters.

For the LVdc cable shown in Table 9.3, resonances start to happen for frequencies higher than 10 MHz; whereas for the HVdc cable, resonances are already present for frequencies after 5 kHz (see Figure 9.19 (a) and (b)). To accurately represent the effect of resonances in high-voltage MTdc networks using a low-voltage setup, the impedances of the LVdc and HVdc cables must be matched. If each 5 meter of LVdc cable is made equivalent to 50 kilometers of HVdc cable, to perform the impedance matching it is necessary to add external lumped components – $0.750\ \Omega$ series resistor, 10 mH series inductance and 11 μF shunt capacitance – to each LVdc cable (see Fig. 9.19 (c) and (d)).

9.5 Distributed Voltage Control Strategy Validation

After understanding the operation of the MTdc network with three terminals, the low-voltage setup was used to validate the distributed voltage control (DVC) strategy developed in this thesis. The final setup is displayed in Figure 9.20, which shows the Opal-RT real-time digital simulator, the Triphase real-time controller, the three voltage-source converters – VSC1 to VSC3 – and the resistance boxes used to form the three-terminal dc grid.

Figure 9.20: MTdc network for the validation of the distributed voltage control strategy.



The experiments for the validation of the DVC strategy are explained next in three steps:

1. the offshore wind farm implementation;
2. the control strategy implementation in the real-time controller and;
3. the experimental results.

1. Offshore Wind Farm Implementation

To validate the developed control strategy, a power curve from a real offshore wind turbine was used. The wind turbine measurements came from the Dutch offshore wind farm in the North Sea, *Egmond aan Zee* (OWEZ).

The offshore wind farm, located circa 20 km from the Dutch coast, occupies an area of 27 km² and has a total installed capacity of 108 MW. It comprises 36 V90 wind turbines, rated at 3 MW each, from Danish manufacturer Vestas Wind Systems A/S. Figure 9.22 shows the OWF power curve, $p_{ac}^{owf}(t)$, used in the DVC validation experiments⁷.

During the experiments, the VSC3 was operated as the converter connected to the offshore wind farm. The active power reference for VSC3 came from an OPAL-RT real-time digital simulator. Figure 9.21, shows the OPAL-RT analog signal, representing the offshore wind farm power, being read by an oscilloscope, whereas Figure 9.23 depicts the offshore wind farm signal flowchart.

First, the offshore wind farm signal was loaded into the OPAL-RT simulator. The offshore wind farm power signal was then outputted

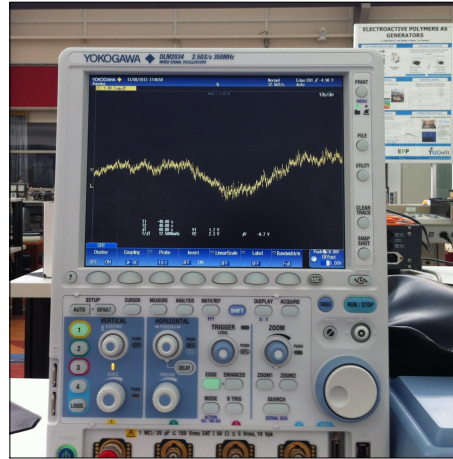


Figure 9.21: Wind power signal from OPAL-RT real-time simulator.

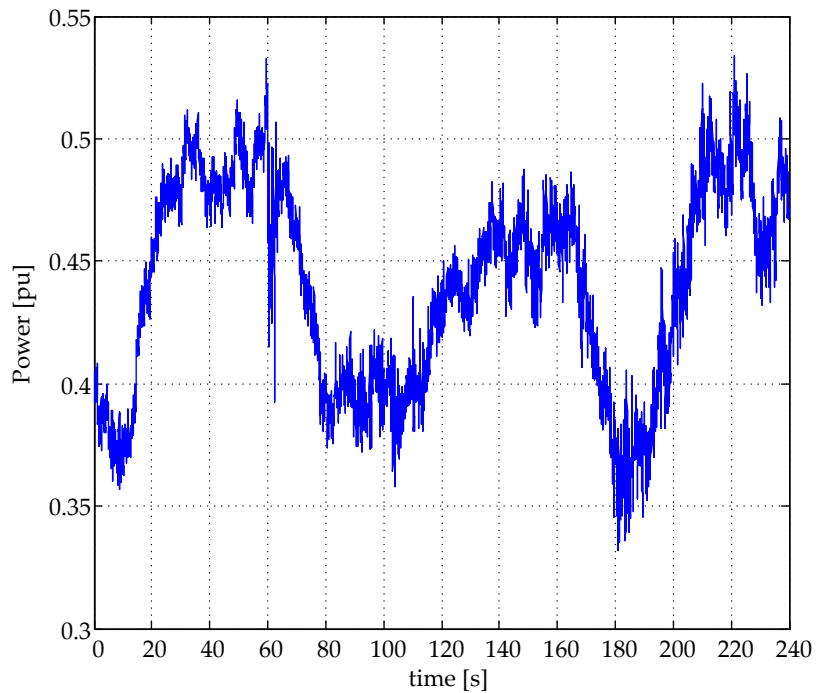


Figure 9.22: Wind power curve used in the DVC strategy validation experiments.

⁷ The power curves obtained from the OWEZ wind farm were for only one offshore wind turbine; hence, had a higher variability than what is expected from the aggregated power of the whole offshore wind farm. Therefore, the power curve shown in Figure 9.22 is the result of a filtering process to smooth the output power of a single turbine into that of the complete offshore wind farm.

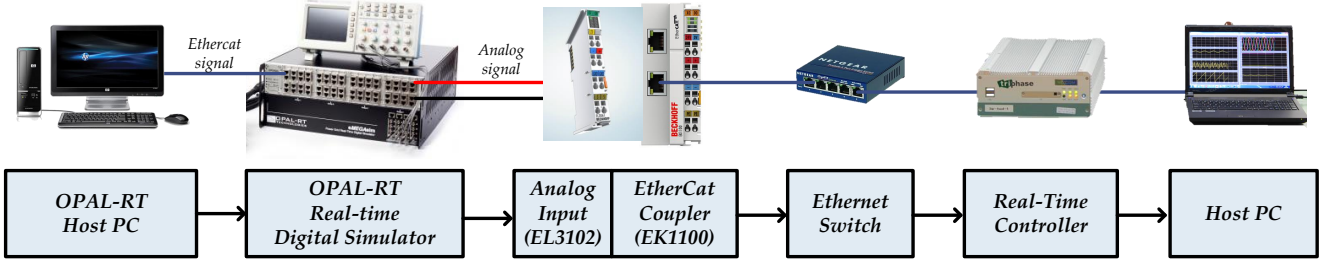


Figure 9.23: Flowchart of the offshore wind farm signal.

by the OPAL-RT as an analog signal, V_o , according to:

$$V_o = \begin{cases} -10 \text{ V; if: } p_{ac}^{owf} \leq 0.3 \text{ pu} \\ \frac{20p_{ac}^{owf}}{3} - 30 \text{ V; if: } 0.3 \leq p_{ac}^{owf} \leq 0.6 \text{ pu} \\ 10 \text{ V; if: } p_{ac}^{owf} \geq 0.6 \text{ pu} \end{cases} \quad (9.4)$$

Secondly, the analog signal was given to a Beckhoff 16-bits differential analog-digital converter (ADC) module (EL3102). The nominal operational range of the ADC is limited to ± 10 V, which is the reason why the OPAL-RT analog output voltage was limited as shown in (9.4).

Although the input-filter limit frequency of the ADC is 5 kHz, the signal sampling frequency was kept much lower, at 64 Hz, which is the original sampling frequency of the OWEZ signal. After the offshore wind farm signal was converted from analog to digital, it was sent to the Triphase real-time controller, re-transformed from a voltage reading into a per unit value according to the inverse of (9.4), and given to VSC3 as an active power reference signal.

2. Distributed Voltage Control Strategy Implementation

The DVC strategy was introduced and explained in detail in Chapter 6. Through simulation of three different case studies, the method was shown to stably control the onshore converters direct voltages, and to successfully steer the power flow inside the MTdc network according to dispatch schemes set by an offshore transmission system operator. In the low-voltage MTdc network setup, its experimental implementation was realised using Matlab/Simulink Stateflow. Figure 9.24 shows the Stateflow block which implements the DVC strategy.

The DVC Stateflow block contains four inputs, which are needed for the optimal power flow procedure, and three outputs which are used to control the power flow in the MTdc network, by controlling the direct voltages of the VSC1 and VSC2 terminals. The complete flowchart of the DVC strategy is shown in Figure 9.25.

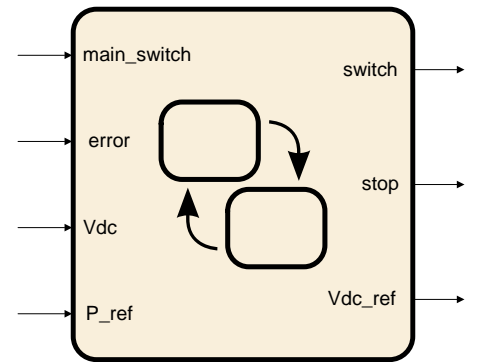
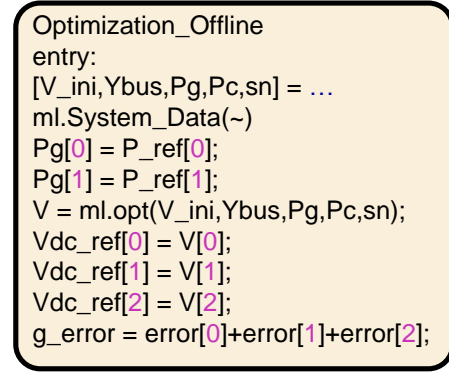
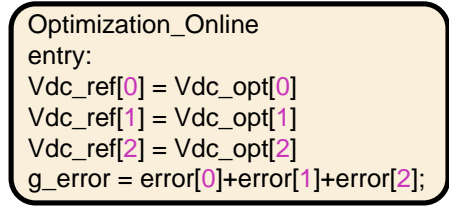


Figure 9.24: Matlab/Simulink Stateflow block with the implementation of the distributed voltage control strategy.

Figure 9.25: Complete flowchart of the distributed voltage control strategy StateFlow block.

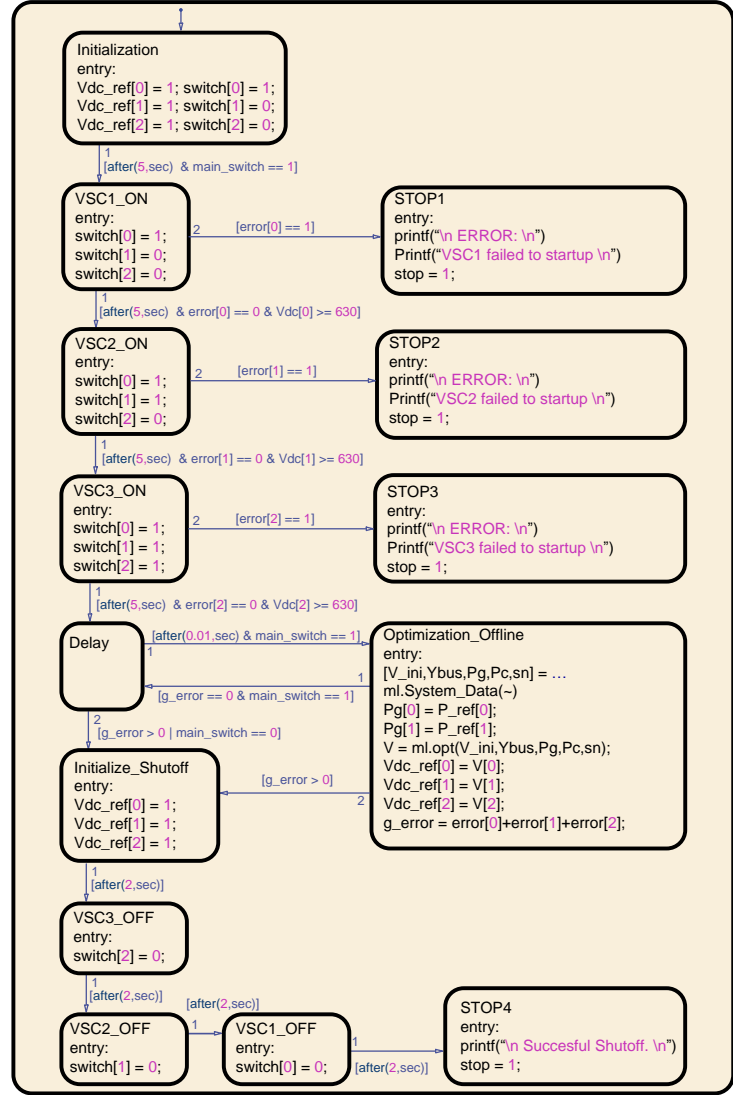


(a) Offline optimisation block



(b) Online optimisation block

Figure 9.26: View of the offline and online DVC optimisation blocks.



The first input – *main_switch* signal – is used to commence the system operation. Upon initialisation, all converters ac-side switches are set to zero, i.e. open, and all voltage references are set to 1 pu. Five seconds after the *main_switch* signal is set to 1, VSC1 starts up and tries to bring the MTdc network voltage to 1 pu⁸.

The status of a converter is read from the second input – *error* signal – as shown in Figure 9.24. If any of the converter fails during the start-up procedure, the system goes into a *STOP* state and the operation is halted.

The third input – *Vdc* signal – contains the direct voltages at the converter terminals and is only used by the DVC Stateflow block during the start-up procedure. If the MTdc network voltage is above 0.9 pu, or 630 V, VSC2 and VSC3 are connected to their ac network, one after the other, following a five seconds delay between them.

The last input – *P_ref* signal – corresponds to the converters active power set-point established by the system operator. In this implementation, only the active power of VSC2 can be established. This is due to the fact that VSC3 is controlling its active power according

⁸ The converters start-up procedure was discussed in detail in Section 9.3.

to the offshore wind farm power output, coming from the OPAL-RT real-time simulator, and VSC1 is taken as the MTdc network slack node, compensating for the total system losses.

The first output of the DVC Stateflow block – *switch* signal – closes and opens the converters ac switches (see Figure 9.2). The second output – *stop* signal – terminates the MTdc network operation, in case of a start-up failure, but also in case of a successful MTdc network shut off.

The shut off procedure works as follows: upon a converter error or disconnection of the main switch, all the direct voltage references are set to 1 pu. The VSC3, which is controlling its active power reference, is the first to be disconnected from its ac network. Then, after a two-second delay, VSC2 is disconnected and after another two-second delay VSC1 is disconnected.

The optimal power flow part of the DVC Stateflow block is composed by two states: *Delay* and *Optimisation*, which generate the last output – the *Vdc_ref* signal – used to control the direct voltages of VSC1 and VSC2⁹.

In the practice, the *Optimisation* state was performed offline, and was substituted for another state, called *Optimisation_Online* (see Figure 9.26 (a)), during the online experiments. This was due to the fact that the converters real-time controller, shown in Figure 9.12¹⁰, was not capable of handling the optimisation algorithm on top of the complete control algorithm of all three converters combined.

3. DVC Experimental Results

The offshore wind farm and the control strategy implementation were finally combined to experimentally validate the distributed voltage control strategy. As previously explained, the three converters assumed different roles during the experiment, i.e.:

1. VSC1: this converter is a slack node, meaning it is controlling the MTdc network voltage;
2. VSC2: is also a slack node, and its active power reference was established by the transmission system operator according with Table 9.4;
3. VSC3: is the offshore wind farm converter, hence, it controls its active power reference according to the power curve shown in Figure 9.22.

The active power reference of VSC2 and the offshore wind power curve of VSC3 were given to the DVC Stateflow algorithm implementation, which then outputted the direct voltage references of VSC1 and VSC2. The results coming from the optimisation, are shown in Figure 9.27.

The optimisation starts at operation time, $t = 25$ s, to allow time for the initialisation of the MTdc network. It then runs between operation time, $25 \leq t \leq 260$ s, which is five seconds shorter than the

¹⁰ The real-time controller is also shown in Figure 9.1, Figure 9.20 and Figure 9.23.

Table 9.4: Active power reference of VSC2 during the DVC validation experiments.

Time [s]	VSC2* [pu]	Time [s]	VSC2* [pu]
0	0.00	140	-0.30
25	-0.50	160	-0.60
40	-0.25	180	-0.20
60	0.00	200	0.20
80	0.25	220	-0.40
100	0.10	240	0.00
120	0.00	260	0.00

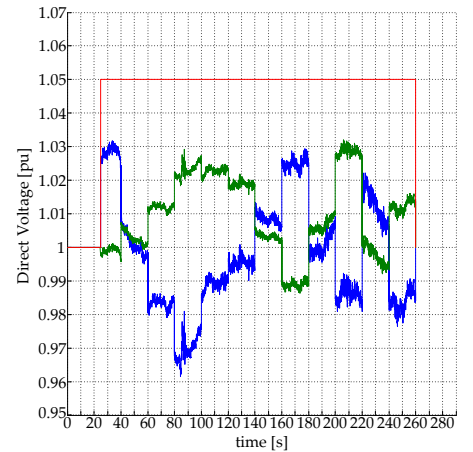


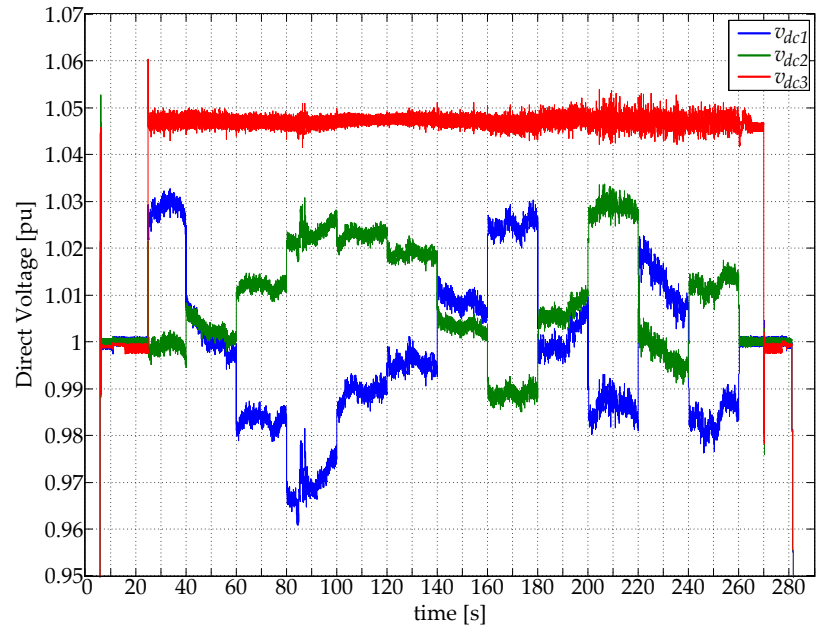
Figure 9.27: VSC direct voltage references resulting from the DVC optimisation.

offshore wind power curve shown in Figure 9.22, to allow time for system shutoff.

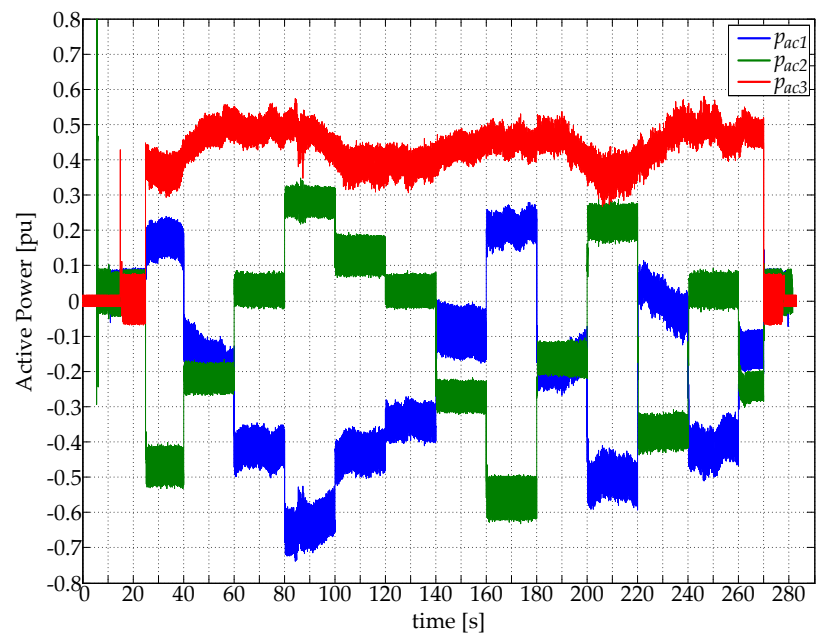
During the optimisation, the DVC algorithm outputs the voltage references of VSC1 and VSC2 to minimise the losses in the MTdc network, and assure that the active power flow scheduling for VSC2, given in Table 9.4, is fulfilled.

The active power and the direct voltage resulting from the DVC strategy validation experiments are displayed in Figure 9.28.

The VSC1 was activated at operation time, $t = 5$ s, the VSC2 was activated at, $t = 10$ s, the VSC3 was activated at $t = 15$ s and it started producing power at $t = 25$ s, when also the MTdc network



(a) Direct Voltage



(b) Active Power

Figure 9.28: Measurements from the MTdc network experimental setup used to validate the DVC strategy.

losses optimisation started.

The fact that the system losses are being optimised is recognisable from the resulting direct voltage of VSC3. The DVC algorithm controls VSC1 and VSC2, so that the direct voltage of VSC3 – the offshore wind farm generation node – is at the higher value possible. In the experimental implementation, a lower limit of 0.95 pu, and a higher limit of 1.05 pu, were given as the direct voltage constraints to the optimisation algorithm.

The first thing that is noticeable from the direct voltage measurements (see Figure 9.28 (a)), is that VSC1 and VSC2 precisely followed the voltage references given by the DVC algorithm. This is due to the PI regulator action on the direct voltage outer controllers of both converters controlling the MTdc network. Additionally, as soon as the optimisation started, the direct voltage of VSC3 was increased close to the higher limit of 1.05 pu (or 735 V) and, as imposed by the DVC algorithm, all voltages stayed within limits during all the system operation, with the exception of some ripple and the start-up transients.

The active power of all three converters during the experiments is shown in Figure 9.28 (b). The graphic shows that VSC3 precisely followed the active power curve from the OWEZ wind farm, displayed in Figure 9.22, due to the PI regulator action on its active power outer controller.

It is interesting noticing, from the active power graphic, that the active power of VSC2 is unperturbed by the variations in the active power of VSC3. Since VSC1 was chosen as the MTdc network slack node, it absorbs the oscillations in the wind power coming from VSC3, to keep the active power going to VSC2 as close as possible to the load flow dispatch values shown in Table 9.4.

Figure 9.29 shows the difference between the VSC2 power, averaged for every second, and the dispatch reference values shown in Table 9.4.

The difference between the average active power of VSC2 and its reference, in percentage terms of the averaged power, is displayed in Figure 9.30 (a), whereas Figure 9.30 (b) shows the difference between the two curves in per unit. The last two graphics in Figure 9.30 show a boxplot analysis of the active power differences. The load flow percentage error, ε_g , is calculated as¹¹:

$$\varepsilon_g = 100 - 100 \frac{p_{dc2}^*}{\bar{p}_{ac2}} \quad (9.5)$$

where;

p_{dc2}^* is VSC2 active power reference according to Table 9.4 [pu] and;
 \bar{p}_{ac2} is the VSC2 averaged active power [pu], calculated according to (9.3).

Although the difference between the VSC2 average power and its reference power is small, in per unit terms, the percentage error between the two curves is somewhat higher.

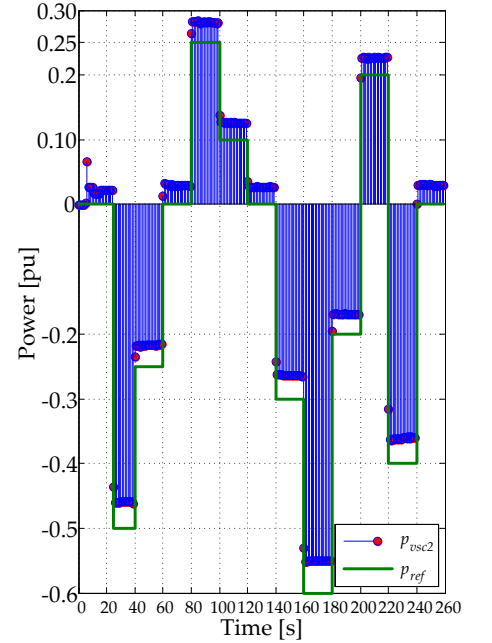
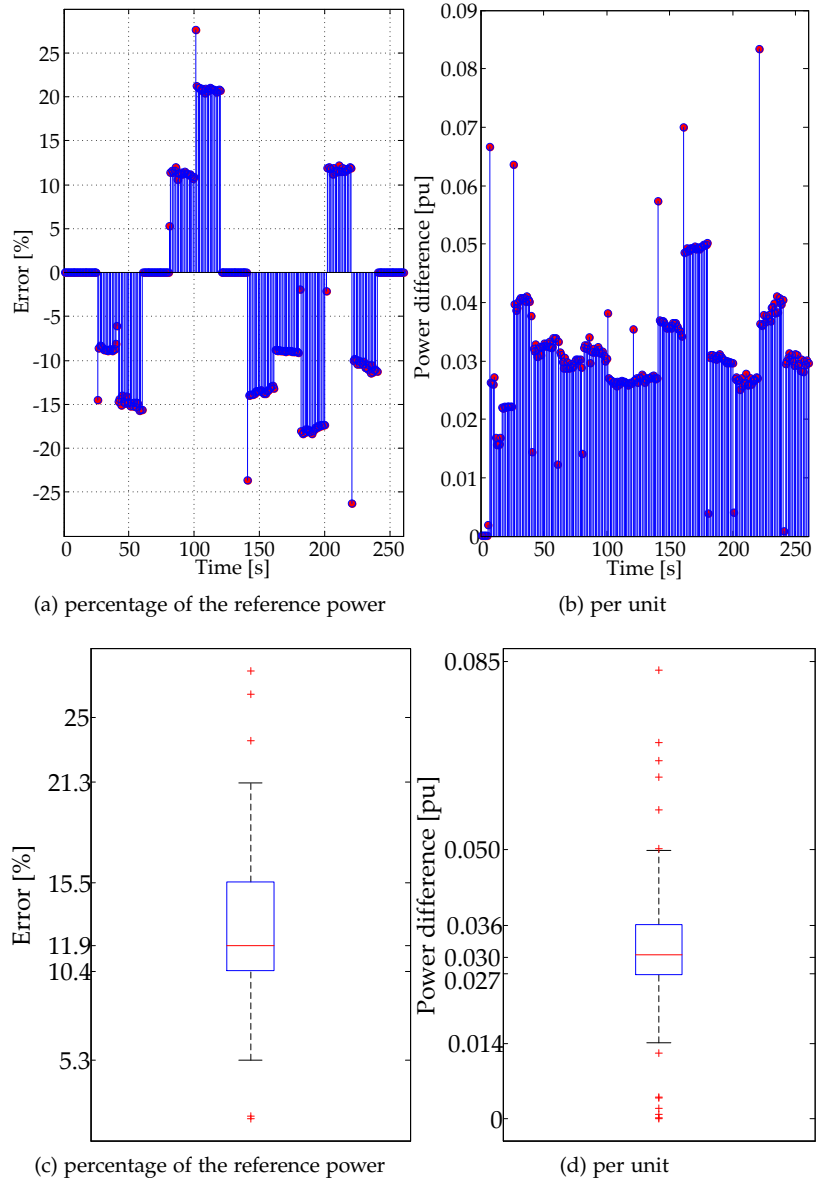


Figure 9.29: Comparison between VSC2 averaged active power and its active power reference.

¹¹ The error was calculated this way to avoid division by zero during the periods in which p_{dc2}^* is null.

Figure 9.30: Difference between VSC2 averaged active power and its active power reference.



The error median value, during the MTdc network operation was around 11.9%, and the error stayed between 10.4% and 15.5% during half of the operation time. However, the median of the difference between the two curves is only 0.03 pu, once outliers – mostly lying on the instants where the active power changes stepwise – are excluded. Moreover, the difference between the two curves stayed between 0.027 and 0.036 pu during half of the MTdc network operation time, as shown in Figure 9.30 (d).

As all the converter sensors have been extensively calibrated, as discussed in Section 9.1, there are two main possible sources for the observed differences between the measured VSC2 active power and the reference values. The first possible source is variations in the MTdc network resistance. However, since the network operation only lasted for circa four minutes, and the resistances of all connection cables have been included in the optimal power flow algorithm, it is unlikely that this significantly contributed to the observed errors.

More likely, the observed errors were a result from the fact that the optimal power flow algorithm considers the active power that actually enters the MTdc network in each node, P_{dc} . Instead, the ac grid-side active power, P_{ac} , was measured since the inverters current sensors could not be calibrated. Hence, the observed errors, albeit small in absolute values, could be further reduced if the inverters efficiency, and losses in the LCL filters, were taken into account when obtaining the direct voltage references in the optimal power flow algorithm.

Nevertheless, as presented in Chapter 6, the DVC control strategy has two main advantages. The first is being able to steer the power flow inside the MTdc network according to different optimisation goals as stipulated by a transmission system operator. In the DVC validation experiments, the object function was the minimisation of the MTdc network losses. Figure 9.31 displays the total system losses during the experiments calculated according to (9.3).

The second, and perhaps most important advantage, is the inherent protection it provides against ac outages affecting the converter stations, since more converters are controlling the MTdc network voltage instead of directly controlling their active power.

9.6 Conclusions

Measurements obtained with a two-terminal experimental setup, in a back-to-back configuration, were checked against the non-linear models presented in Chapter 4. As in Chapter 8, within small error margins, the simulation results agreed with the direct voltage, the active power and the reactive power measurements obtained in the laboratory. During the experiments, all controls worked as expected and the system response was both accurate and fast, i.e. with no steady-state errors and with step responses of less than 100 ms.

The start-up transients of the LV-MTdc network were also shown to be fast, as it took less than 200 ms for the phase-locked loop controllers to synchronise the converter (dq) reference frame to the ac network voltage phasor, and it took less than 500 ms before the direct voltage in the MTdc network was brought to its nominal value once the converters were operational. Although it can be done very fast, the start up of high-voltage MTdc networks should be done in a slower fashion, to avoid stresses on the dc cables and VSC-HVdc stations.

By adding external lumped components, it is possible to match the frequency response of a LV-MTdc network to reproduce the harmonic content and the overall behaviour of a HV-MTdc network. To improve the impedance matching, the converters dc output capacitors, and eventual dc limiting reactors, would also have to be taken into consideration.

Finally, the results have shown that the distributed voltage control strategy was able to successfully operate and control the MTdc network. The complete system had a very good dynamic response, with

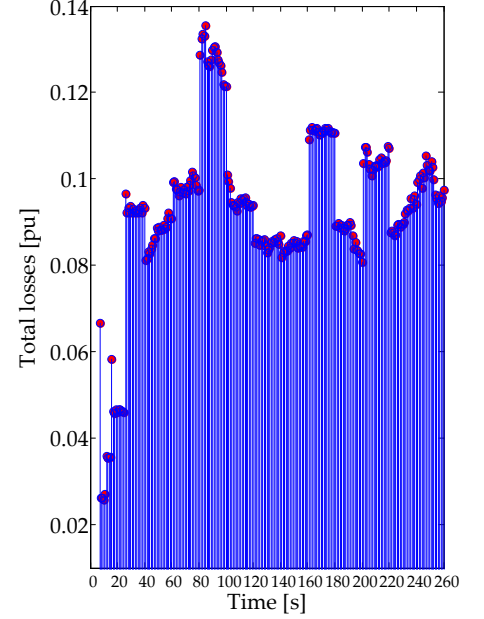


Figure 9.31: Averaged total losses in the MTdc network.

transients lasting less than 100 ms. What is more important, the method was capable of controlling the power flow inside the MTdc network with circa 90% precision.

10

Conclusions

Extraordinary claims require extraordinary evidence.

Carl Sagan, "Encyclopaedia Galactica," in *Cosmos: A Personal Voyage*. Episode 12, 01'24", December 14, 1980.

As discussed in Chapter 1, global energy consumption is rising as the world population increases, and more people come out of poverty as a result of growing economies and intensified urbanisation processes. In this context of rising energy needs, a secure and reliable supply of electricity is becoming a quintessential component of modern societies.

The thesis main objective was to examine the utilisation of multi-terminal dc networks to foster the integration of remotely located renewable resources, with special focus on the connection of offshore wind farms in the North Sea. Hence, the introduction chapter presented the main challenges for the development of multi-terminal dc networks together with the objectives and research questions which motivated the work.

Chapter 2 examined the available HVdc transmission technologies for constructing a multi-terminal dc network in the North Sea, as well as what is the best possible HVdc system configuration and network topology to accomplish such aim.

A list of reasons why, for the integration of some offshore wind farms, direct current systems are preferred over alternating current systems was given in Chapter 3. Additionally, the chapter discussed the importance of selecting the right system architecture for a successful development of the North Sea Transnational Grid. After that, a dc load flow algorithm was developed, and an analysis was performed on a possible MTdc network layout involving the North Sea countries with the highest expected offshore installed capacity.

In Chapter 4, a dynamic model of the complete MTdc network was developed in which the combined dynamic response of the main components inside the system can be simultaneously studied. The chapter has shown in detail the elements inside a VSC-HVdc station and has analysed in depth its control structure.

Using the models developed in Chapter 4, a comparison of the most common strategies for controlling the direct voltage in MTdc networks was performed in Chapter 5. The methods were compared

10.1. Final Conclusions

10.2. Recommendations for Future Research

in a case study using a four-terminal radial MTdc network linking two onshore grids and two offshore wind farms.

A novel control strategy for MTdc networks, named *Distributed Voltage Control* strategy, was developed in Chapter 6, based on Chapter 3 findings that a higher number of slack nodes¹ means a more reliable MTdc network.

¹ i.e. VSC-HVdc terminals controlling their direct voltage.

Chapter 7 has analysed the effects of ac and dc faults on the operation of MTdc networks, and determined what is needed for a MTdc network to withstand and recover from faults in the connected ac systems, or in the dc grid itself, without halting its operation.

Small-signal models of the MTdc grid and the voltage-source converters were developed in Chapter 8. Next, based on the VSC non-linear models developed in Chapter 4, a small-signal model was created. The model combines the hardware and complete control structure of the VSC in a state matrix and an input matrix. The VSC small-signal model was validated against simulations from the non-linear models of Chapter 4, and against measurements obtained from the laboratory setup using a voltage-source converter in a STATCOM configuration.

In Chapter 9 a low-voltage MTdc network was built to reproduce the behaviour of a high-voltage MTdc network in a laboratory environment. First, the setup was described, step-by-step, before achieving its final form. In a network with three converters connected via short cables, measurements were used to explain the system start up procedures, and to gain first insights on the operation of the MTdc network. Finally, after adding external resistances for impedance matching, the MTdc network was successfully operated and controlled using the distributed voltage control strategy.

This chapter presents the thesis final conclusions and recommendations for future research.

10.1 Final Conclusions

Only three MTdc networks exist to date. Furthermore, all of them use HVdc Classic technology and have just three terminals. Hitherto, high-voltage MTdc networks using VSC-HVdc technology were not built, although the reasons which slowed the evolution of dc networks in the past – i.e. the need for mechanical switches to reverse power flow, complex master control structures, and need for communication links between the converter stations, are all currently surmountable with state-of-the-art technology. Additionally, the lack of previous experience cannot be used as an argument to justify the lack of MTdc networks with VSC-HVdc technology. One of this thesis main contributions is pinpointing the main challenges on the way to the development of MTdc networks.

Therefore, the thesis final conclusions, based on the objectives presented in Chapter 1, are classified according to these five challenges, viz.: system integration, dynamic behaviour, power flow control, stability and fault behaviour.

System Integration

Based on the performed literature review, state-of-the-art VSC-HVdc transmission systems using modular multilevel converter topologies are currently the best option for the development of a MTdc network in the North Sea due to their smaller filter and, consequently, space requirements, and higher control flexibility than the Classic CSC-HVdc or earlier VSC-HVdc technologies.

Additionally, according to the research performed in Chapter 2 and Chapter 3, the best configuration to start the development of high-voltage MTdc networks will be through a parallel-radial topology using a symmetric monopolar configuration. This will allow the system to develop modularly, will keep initial capital costs down and will make it easier to face dc contingencies.

Nevertheless, not all offshore wind farms in the North Sea should be connected to the North Sea Transnational Grid by default. After a technical assessment, such as the one performed in Chapter 3, the final judgment to decide whether an offshore wind farm should be part of the NSTG requires also a thorough economic analysis, which was out of the thesis scope.

What is clear though is that for multi-terminal dc networks to finally become widespread, they will need to embrace a modular architecture, and slowly grow with time to more complex meshed networks, in a development similar to that of ac networks. In that sense, the development of high-voltage dc-dc converters would allow HVdc transmission systems with different rated voltage levels to be interfaced, allowing a more modular development of MTdc networks.

Still, the system designers have to establish and coordinate the global design rules, the performance standards, and the interfaces between the system components before MTdc network construction starts. Therefore, in the NSTG case, the system integration, optimisation, and coordination should be assigned to an independent offshore system operator, responsible for an offshore grid code and a road map development plan, which constitutes a strong recommendation for future research².

The successful development of a low-voltage multi-terminal dc network, presented in Chapter 9, was possible since the system integration concepts of Chapter 3 were put in practice: the system growth happened organically with time³, and the global design rules⁴ were established at earlier development stages. However, system integration will be harder to accomplish in high-voltage dc networks than in low-voltage – or even medium-voltage – dc networks due to the multiple international stakeholders needed, but also due to the larger system scale and capital costs involved. Therefore, microgrids and smartgrids using dc technology are much more likely to appear before dc supergrids. Nevertheless, with the correct incentives and proper coordination, the development of high-voltage multi-terminal dc networks is only a matter of time.

Thesis objectives on System Integration were:

- Analyse what has prevented the development of MTdc networks in the past.
- Perform a review of HVdc transmission technology, and configurations, to identify the best option for the development of a MTdc network in the North Sea.
- Compare different topologies for construction of MTdc networks.
- Establish when the transmission system of an offshore wind farm should be done in direct current.
- Study the role and impacts of system architecture on the development of MTdc networks for offshore wind applications;
- Form a LVdc network by connecting more than two power electronic converter on their dc sides.

² See the fourth recommendation point in Section 10.2.

³ First one converter was tested as a STATCOM, then two converters were connected in back-to-back, and finally three converters were put together to form a parallel-radial multi-terminal dc network using a symmetric monopolar configuration.

⁴ The basic rules were: the converters rated power, direct voltage levels and control dynamics.

Thesis objectives on Dynamic Behaviour were:

- Create non-linear dynamic models of the most important modules inside MTdc networks: i.e. the offshore wind farms, the VSC-HVdc converters, the dc cables and control systems.
- Establish how the models are connected to each other based on their signal flow.
- Analyse the control structure of a VSC-HVdc converter station.
- Test and validate the developed models on real power electronic converters.

⁵ Active and reactive power, and direct voltage step response transients lasted less than circa 100 ms as shown in Chapter 9.

Thesis objectives on Power Flow Control were:

- Develop a load flow algorithm to analyse the power flow in MTdc networks with more than one slack node.
- Compare the most common control strategies for MTdc networks.
- Evaluate how to optimise the power flow in MTdc networks.
- Develop a novel direct voltage control strategy capable of reliably and securely operating a MTdc network during steady-state and fault scenarios.
- Test the novel control strategy on the developed LV-MTdc laboratory setup.

Dynamic Behaviour

To determine the dynamic behaviour of the complete MTdc system, the thesis relied on the development of modular dynamic models. When developing dynamic models one is always faced with a trade-off between computational time and level of detail. The choice of minimising the model computational time and maximising its level of detail should always take into consideration the model main purpose.

To design control strategies for multi-terminal dc networks, which was the main drive for the development of dynamic models in this thesis, averaged non-linear models of the most important system modules were sufficient.

If the models are built modularly, identifying how the different system modules are connected to each other is more important than the module level of detail, since it becomes transparent to the complete model. That is why the models developed in Chapter 4, specially the control models of the voltage-source converters, could easily be tested and validated in the low-voltage multi-terminal dc network setup. With that approach, all that was needed, to go from simulation to the experiments in the laboratory, was to substitute the converter model module with the measurements coming from the power electronic converters.

To apprehend the combined dynamic behaviour of a MTdc network such as the North Sea Transnational Grid, the most important is to model the dynamic behaviour of its the power electronic converters as they decouple the offshore wind farms and ac network dynamics from the dynamics of the dc grid. Results from the experiments have shown that the dynamic behaviour of the voltage-source converters is fast⁵, and accurate. Hence, with proper power electronics control design, the dynamic behaviour of the complete system can be fast and accurate as well, thus, dynamic behaviour issues will not hamper the development of multi-terminal dc networks.

Power Flow Control

A dc load flow algorithm, such as the one developed in Chapter 3, gives knowledge of how the power is flowing inside a MTdc network and, accordingly, is crucial in developing strategies to control that power flow.

In high-voltage MTdc networks, where the rated power of its terminals will be essentially similar to one another, the power flow control should be accomplished indirectly through the control of the system direct voltages, instead of directly trying to control the active power in each network node. This increases the MTdc network reliability, as shown in the N-1 security analysis performed in Chapter 3.

Current methods for controlling HVdc transmission systems, discussed in Chapter 5, were not devised for controlling multi-terminal dc networks. Furthermore, they were not developed with expansion and flexibility as their prime objectives. For instance, the droop

control, which is the most employed control method in ac networks, where the frequency of all nodes has to be kept equal, cannot control the power flow in multi-terminal dc networks since, if all the nodes had the same voltage, there would be no power flow.

To optimise the power flow in MTdc networks, all nodes which are not connected to generating plants, should be working inside the system as slack nodes, i.e. they should be controlling the system direct voltage. Then, the power flow can be controlled and optimised to minimise the system losses, maximise its social welfare or accomplish any other goal or constraint which can be envisioned by its transmission system operator.

The distributed voltage control strategy, introduced in Chapter 6, was developed with expansion and flexibility as its prime objective to overcome the shortcomings of the available MTdc network control methods studied in Chapter 5. The distributed voltage control strategy was validated with success in Chapter 9. The method was used to control the power flow inside the three-terminal low-voltage dc network with circa overall 90% precision, while providing the complete system with a very good dynamic response with transients lasting less than 100 ms. If the converter losses are included in the optimal power flow problem, the accuracy of the distributed voltage control strategy can be further improved.

The DVC strategy does need communication to control the power flow inside the MTdc network, but as the communication can happen in control cycles in the order of minutes, fast telecommunication links are not needed. Moreover, the communication is only performed between a node and the transmission system operator, and not amongst nodes, which reduces the number of necessary links. Without communication, the development of microgrids, smartgrids or supergrids will be deprived of strength and efficiency.

What is important is that the system operation remains stable in case of communication failures, as is the case with the DVC strategy. In case of communication loss, the DVC strategy would lose its ability of controlling the power flow, but would keep the operation of the MTdc network stable.

Stability

As introduced in Chapter 1, the stability of a system is related to its ability to reach a new operating point after being subject to a disturbance. In dc networks, the system stability depends on the power flow balance between all interconnected nodes, i.e.: a MTdc network will be stable if, at any given time, the sum of the active power entering the system is equal the sum of the power exiting the system.

That is why a higher number of nodes controlling the system direct voltage will mean a more stable dc network. Nodes controlling the MTdc network direct voltage do so by making sure the power inside the system is balanced. Momentary imbalances in the MTdc

Thesis objectives on Stability were:

- Development of linear small-signal models of the MTdc network components for stability analysis.
- Analysis of the system eigenvalues and their sensibility to parametric variations.

system power flow will produce variations in the direct voltages of its terminals, which will then change the dc network operating point.

The small-signal model of the MTdc grid, developed in Chapter 8, has shown that these networks are marginally stable systems, and through feedback control of the converter direct voltage the system poles move away from the unstable region of the root locus plane. Hence, in the same way its dynamic behaviour was dictated by the converters behaviour, the small-signal stability of multi-terminal dc networks is dictated by the stability of its power electronic converters.

The analysis performed in Chapter 8, suggests that the voltage-source converter eigenvalues are resilient from parametric variations in the values of its hardware components. Variations in the converters LCL filter values and output capacitor values, have shown that dynamic performance deteriorates but the converters eigenvalues remain stable. However, careful consideration should be made when designing and tuning the converter controllers, specially the reactive power and the PLL controllers, which relate with voltage stability issues on the converter ac-side filter.

Fault Behaviour

Thesis objectives on Fault Behaviour were:

- Use the develop models to study the behaviour of MTdc networks during ac and dc contingencies.
- Investigate the influence of grid code requirements on MTdc networks during ac contingencies.
- Analyse the impact of the HVdc transmission system configuration on dc contingencies management.

The development of dc networks, be them microgrids or supergrids, will require these networks to remain operational when faced with contingency scenarios. The fault analysis performed in Chapter 7 has shown that, with the correct provisions, a multi-terminal dc network, such as the North Sea Transnational Grid, can be resilient against contingencies in any of the interconnected ac networks, but also in the dc grid itself.

To counteract ac contingencies, the VSC-HVdc terminals will have to quickly restore the active power balance inside the MTdc network. The results from Chapter 7 have shown that ac faults happening in the onshore system nodes, particularly in nodes controlling the system direct voltage, can be very demanding⁶. A sudden surplus of active power in a MTdc network can quickly bring the system direct voltage to values above 1.2 pu in less than ten ac network cycles⁷. In those cases, the influence of the ac grid code requirements on the MTdc network behaviour during the fault is vital.

During an ac contingency, a VSC-HVdc terminal is on a tug war between the ac network, which requires reactive power, and the MTdc network, which requires active power. Too stringent grid code requirements demand that the converter should provide close to 100% reactive power compensation to the ac network in cases where the ac grid voltage dips below 0.5 pu. This leaves the converters with little active power capability, which can have a negative impact on all the converters in the MTdc network and, consequently, also on the other interconnected ac networks.

There are several solutions to deal with this issue: load shedding, fast power reduction methods, installation of dc choppers at

⁶ Faults happening in the ac-side of a generating node does not pose a threat to a MTdc network as, when power is lost, the nodes controlling the system direct voltage will quickly adjust their active power levels to keep the system stable.

⁷ In a 640 kV HVdc system (± 320 kV), that is an overvoltage of 128 kV in less than 200 ms.

the wind farms, overrating the power electronic converters, or making the ac grid codes less stringent with their reactive power requirements. The latter solution was tested in Chapter 7 and produced a reduction of circa 75% on the observed overvoltage during an ac contingency, from over 1.20 pu to a little over 1.05 pu.

The situation regarding MTdc network fault changes when it comes to dc contingencies. Hitherto, there are not many options for dealing with dc fault situations. The development of dc circuit breakers is still incipient and, amongst the technologies analysed in Chapter 7, the only two which can act fast enough to avoid interruption of the MTdc network operation – the solid-state breaker and the ABB Hybrid breaker – need to improve their ratings before they can be used in practice. Until the dc switch breakers are commercially available, the most well-suited solution to counteract dc contingencies is to build the MTdc network using a symmetric monopolar configuration in conjunction with direct current limiting reactors.

10.2 Recommendations for Future Research

This section indicates possible areas for future research on the field of multi-terminal dc networks, and improvements to the work performed in this thesis. A list of these suggestions, broadly arranged by chapter, is given below:

Chapter 2: HVdc Transmission Systems

- Current-source converters using HVdc Classic technology are not suitable for the offshore wind farm installations, but their power ratings make them attractive for the onshore installations. The control and protection aspects of these hybrid MTdc networks should be assessed.
- Other alternatives to voltage-source converters and line-commutated current-source converters need to be appraised for high-voltage MTdc applications. A promising possibility is to create force-commutated current-source converters using integrated gate-commutated thyristors (IGCT) technology. The dc fault handling capabilities of these converters could be a great advantage in developing multi-terminal dc networks.

Chapter 3: Network Operation and Power Flow

- Research should focus on performing power flow dispatch schemes capable of improving the operation of both the dc network and the interconnected ac networks. To accomplish this, the distributed control strategy would need an expanded multi-object optimisation algorithm which also considers the ac networks load flow.
- For the North Sea Transnational Grid, a detailed dc grid code should be formulated with design rules for system performance during steady-state, dynamic and contingency scenarios.

Chapter 4: Dynamic Modelling

- To study possible resonances and adverse control interactions between the offshore wind farms and the voltage-source converters, their dynamic model need to be further improved to include the converter switching behaviour, more detailed offshore wind farm controls, and its collection system.
- The model of the cables in the multi-terminal dc network should be expanded to include frequency-dependent transmission line models, especially for the analysis of dc contingencies.

Chapter 5: Control of MTdc Networks

- Other multi-terminal dc networks control strategies should be compared to the distributed voltage control strategy, preferably using the experimental low-voltage multi-terminal dc network developed.

Chapter 6: The Distributed Voltage Control Strategy

- The accuracy of the distributed voltage control strategy should be further researched with regards to direct voltage measurement errors, variation of the MTdc network cables resistance with temperature, and wind farm power production prediction models.
- A sensitivity analysis resulting from the dc load flow jacobian matrix could be used to improve the accuracy of the distributed voltage control strategy by adjusting the direct voltage reference of the converter terminals based on the power flow error measurements.

Chapter 7: Fault Analysis

- The effective consequences of more stringent grid code requirements on helping ac networks recover from contingencies should be further researched and, when not necessary, recommendations should be given to lower ac grid code requirements in favor of dc grid requirements.
- Dynamic models of modular multi-level HVdc converters, specially full-bridge submodule topologies, should to be built to analyse their capability of handling dc contingency scenarios in multi-terminal dc networks.

Chapter 8: Small-signal Analysis

- The stability analysis should be enlarged to include the small-signal model of an offshore wind farm. Afterwards, all three models – offshore wind farms, voltage-source converters and MTdc network – could be combined into a single model to obtain the eigenvalues of the complete system.

Chapter 9: Laboratory Setup and Testing of a LV-MTdc System

- Rather than offline, the optimisation block of the distributed voltage control strategy should be implemented online, i.e. concomitantly with the MTdc network operation. Research should focus on optimisation algorithm methods more suitable for real-time implementation.
- In addition to the resistor boxes, the impedance matching between the low-voltage dc network and a high-voltage one needs to be extended to consider also its energy storing elements, i.e. capacitors and inductors.
- The low-voltage MTdc system should be further expanded. Experiments could be envisioned to test the MTdc network operation under different configurations and topology, e.g. in a meshed dc network. Additionally, experiments could also include a dc-dc converter and/or a current-source converter. Finally, controlled tests should evaluate more in detail protection measures against ac and dc contingencies.

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Part VI

Appendixes

A

Offshore Grid Projects

Great discoveries and improvements invariably involve the cooperation of many minds.

Alexander Graham Bell

A.1 The NSTG Project

The research work contained in this thesis was performed inside the North Sea Transnational Grid project. The financial support was given by Agentschap NL, an agency of the Dutch Ministry of Economic Affairs, Agriculture and Innovation. The project – jointly performed by Delft University of Technology and ECN¹ – had a duration of 4 years, starting from October 2009.

The main project goal was to identify and study technical and economical aspects with regard to the development of a transnational electricity network in the North Sea for the connection of offshore wind power and to promote energy trade between countries [218]. Apart from the main goal, there were other four main objectives: determination of the optimal offshore transnational grid configuration; definition of the NSTG operation and control strategy; coordinated grid expansion plan and social-economic evaluation. To achieve these objectives, the NSTG project was divided in 7 work packages (WP). The relationship between the different work packages is shown in Figure A.1, together with the project timeline. A brief description of the work performed on each WP is given below.

WP1 – Inventory of available technology, modularity and flexibility

Investigated the technological options from the perspective of modularity and flexibility. It identified critical technical aspects of a

A.1. The NSTG Project

A.2. Review of Other Projects

¹ Energy Research Centre of The Netherlands.

<http://www.ecn.nl/home>

The black arrows show the interdependency between the work packages.

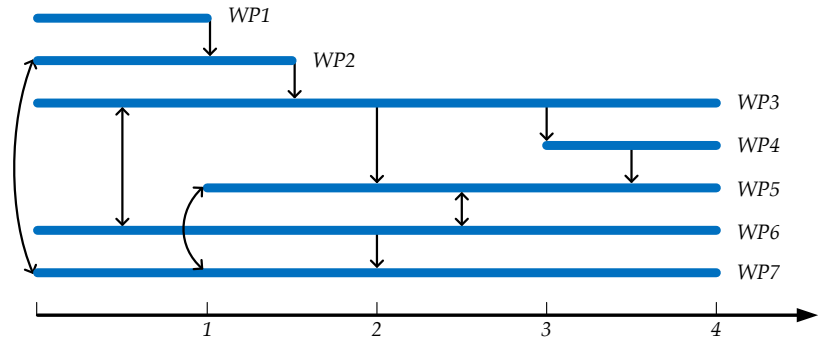
The work presented in this thesis is positioned inside WP3 and WP4, led by Delft University of Technology.

More information on the project, including reports, can be found online: <http://www.nstg-project.nl/>

This chapter is based on the following publication:

A. A. van der Meer, R. Teixeira Pinto, M. Gibescu, P. Bauer, J. Pierik, F. Nieuwenhout, R. Hendriks, W. Kling, and G. van Kuik, "Offshore Transnational Grids in Europe: the North Sea Transnational Grid Research Project In Relation To Other Research Initiatives," in *Proceedings of the 9th International Workshop on Large-Scale Integration of Wind Power Into Power Systems As Well As On Transmission Networks For Offshore Wind Power Plants*, Quebec, Canada, October 2010.

Figure A.1: NSTG project timeline.



transnational grid and generated the input for the evaluation of different transnational grid topologies in WP 2.

WP2 – Technical and economic evaluation of different solutions

Different scenarios for the NSTG were evaluated in detail with regard to the connection of offshore wind farms (individual connection, national interconnection and meshed grid) and the transmission technology used, i.e HVac or HVdc.

WP3 – NSTG operation and control

In this work package the dynamic models of the NSTG main components were built. Additionally, a novel control strategy aiming at flexible and modular operation of the NSTG was developed.

WP4 – Real-time multi-terminal network testing

The results obtained from WP3 were experimentally tested. For this purpose, a small multi-terminal LVdc network was built in the ESE department of Delft University of Technology. The experiments also comprised a validation of the developed dynamic models and controllers.

WP5 – Optimisation of NSTG solutions

A multi-objective genetic algorithm optimisation was used to optimise the NSTG topology and controls according to the results obtained in WP2 and further developed in WP3 and WP4.

WP6 – Grid integration: planning, congestion and stability

Large-scale steady-state and dynamic models were developed to simulate the interaction between the transnational grid and the ac power systems of the neighbouring countries.

WP7 – Costs, benefits, regulations and market aspects of the NSTG

An existing market model, the COMPETES model, was used to simulate European markets for different NSTG configurations. It was

applied to obtain an estimate of the NSTG effect on the market prices and, thereby, access the benefits of the increased interconnection capacity.

A.2 Review of Other Projects

As shown in the previous Sections, the use of HVdc transmission systems for integration of offshore wind farms might represent a better option both in technical and economical terms. Once several offshore wind farms are built, the development of an offshore grid can be even more advantageous by:

- providing developers an easier way to connect offshore generation;
- reducing efforts required to get offshore wind power approved;
- reducing the number of cable connections and transmission losses;
- allowing electricity trade between countries;
- reducing the variability of the generated wind power;
- increasing the stability and reliability of interconnected national grids;
- providing better power flow controllability.

In Europe, the need for a coordinated energy infra-structure planning was recognised as early as 2006 when the European Energy Commission laid down the course of action towards a trans-European network for electricity [219].

To foster the integration of renewable energy into their energy matrices, nine European countries² signed, at the EU Energy Council in Brussels on 7 December 2009, a political declaration for joint cooperation on the development of a transnational electricity infrastructure in the North Sea. The document recognises the offshore wind energy importance in helping Europe meeting its 2020 energy targets and welcomes research initiatives for an effective offshore grid infrastructure planning and coordination. This joint collaboration is known as the North Seas Countries Offshore Grid Initiative [220].

This political declaration is a consequence of previous project efforts on the establishment of an offshore grid in the North Sea. Therefore, before designing the North Sea Transnational Grid, the system integrators need to be aware and to build on results and conclusions already drawn by earlier projects [12,218]³.

TradeWind (Nov. 2006 - Feb. 2009)

The TradeWind project, financed under the EU Intelligent Energy-Europe (IEE) programme, dealt with issues regarding reliable integration of large wind generation and its impacts on the trans-European power markets⁴. The project, which involved 8 European

² Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Sweden and the United Kingdom.

³ For concision, only a selection of relevant North Sea Transnational Grid projects are here introduced, viz.: TradeWind, EWIS, Energy [R]evolution, Offshore-Grid, IEA Wind Task 25, and TWENTIES.

⁴ More information on the TradeWind project is available online at: <http://www.trade-wind.eu>.

⁵ The 2015 scenario was willingly chosen to allow for comparisons with the EWIS study [222].

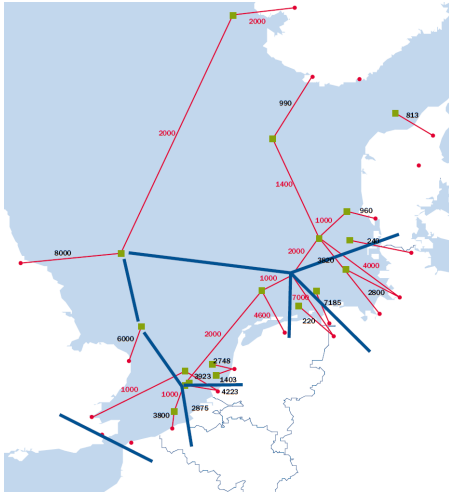


Figure A.2: TradeWind view of a meshed HVdc network on the North Sea.

⁶ The work packages were: Present Situation and Market Aspects; Scenarios and Exchange Schedules; Power System Analysis; Operational Aspects; Cost Analysis and Legal Aspects; and Communications. More information on the EWIS project is available online at: <http://www.wind-integration.eu>.

countries, focussed on cross-border power flows derived from increasing wind power penetration scenarios in Europe [221].

In total, there were 8 work packages distributed over 3 phases: a preparatory phase (WP2 - WP4); a simulations and analysis phase (WP5 - WP7); and a recommendations phase (WP8).

The study time horizon, which went until 2030, included short, medium and long term scenarios. The medium term scenarios were 2008, 2010, 2015⁵ and 2020.

The study emphasis was on institutional, market, and regulatory aspects. Even though the project modelling included technical aspects of wind integration, its primary objective was not a detailed offshore grid design. Figure A.2 shows the project view of the North Sea transnational grid as a meshed HVdc network [221].

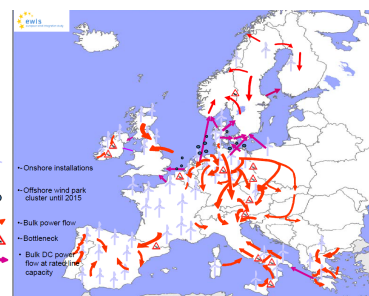
Finally, the study concludes that, at a European level, an offshore grid can be an economically beneficial solution, and it recommends that further studies should focus on detailed planning and optimisation of offshore grid solutions in the North and Baltic Seas [218].

EWIS (Jun. 2007 - Mar. 2010)

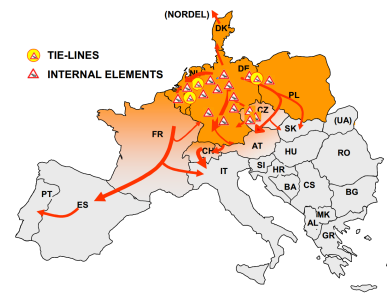
Along with TradeWind, the European Wind Integration Study (EWIS) was one of the first to analyse the integration of large wind energy amounts generated onshore and offshore at a pan-European level. The European Network of Transmission System Operators for electricity (ENTSO-e) initiated the study which involved 13 countries and had 6 work packages [223]⁶.

The project main research focus was, from a market and TSO perspective, how to efficiently accommodate wind generation while ensuring safe electrical energy supply. The EWIS study provided detailed power flows analysis inside the ENTSO-e network – as well as dynamic system behaviour studies – for different wind penetration scenarios. The goal was to demonstrate that the necessary ac network reinforcement costs, although significant in absolute terms, will be compensated by the wind energy generation benefits [223].

Figure A.3 display power flow patterns and bottlenecks for Europe in 2015 considering a high north wind scenario. EWIS results constitute an important platform for offshore wind farms and off-



(a) 2015 physical power flow patterns (high wind north)



(b) Detected bottlenecks during N-1 conditions of UCTE north wind scenario

Figure A.3: Results from the EWIS project.

shore grid infrastructure investigations with time horizons beyond 2015 [218].

Energy [R]evolution (2007 - 2012)

The Energy [R]evolution study, which started in 2007, is an initiative led by Greenpeace to suggest feasible solutions to halve, by 2050, worldwide CO₂ emission levels when compared to 1990 levels. The study, now in its fourth version, developed from this initial concept to become an energy outlook on available sustainable energy forms worldwide [224].

On September 2008, Greenpeace launched a dedicated study, in partnership with Belgian company 3E, on the development of an offshore North Sea transnational grid [225]. The study intended to show that, via a transnational network, offshore wind power can be used to supply base electricity in the North Sea region, because aggregating wind farms over a wide geographic area reduces wind generation variability.

According to the report, between 2020 and 2030, 68 GW of wind power will be installed in the North Sea amongst more than a 100 offshore wind farms. The study recognises that, given the total expected installed capacity, HVdc systems will play a key role in the development of the North Sea transnational grid. Figure A.4 shows the project offshore grid topology vision for the 2030 scenario [225].

OffshoreGrid (May 2009 - Oct 2011)

The OffshoreGrid project was executed by a consortium of European research centres, universities and consultancy partners, and was funded similarly to TradeWind via the IEE programme [226]. It aimed at providing recommendations for policy makers and TSOs concerning technical, policy, and economic aspects related to development of offshore grids.

The project results served as input for the EU electrical infrastructure objectives stated in the Second Strategic Energy Review, which includes the development of a Baltic interconnection plan, a blueprint for the North Sea transnational grid and the Mediterranean ring [218].

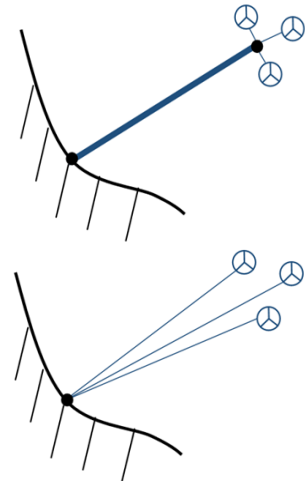
The project had four basic stages:

1. studying options to connect the offshore wind farms to shore;
2. drawing cost efficient offshore network designs;
3. analysing different concepts for building offshore grids and;
4. providing general recommendations.

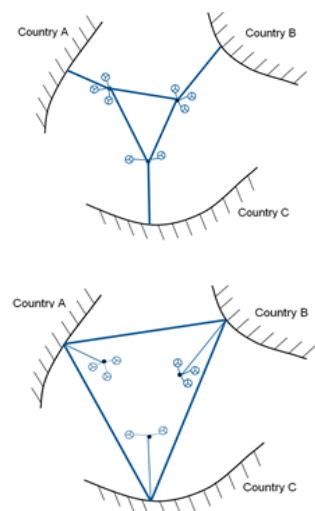
The first phase identified possible ways connecting OWFs to shore: radial and hub connections (see Figure A.5). The study found that hubs can be beneficial if the OWFs are not built at once. However, hubs installation need to be planned and have good coordination



Figure A.4: Greenpeace offshore grid topology proposal.



(a) Possibilities for the single OWF



(b) Possibilities for the MTdc Network

Figure A.5: Possible ways to connect OWF to the NSTG according to the OffshoreGrid project.

with the OWFs development plan [185]. Hence, instead of randomly building OWFs, the best is to focus on a few hubs at a time. From 321 possible OWF projects, the OffshoreGrid study suggested that 114 should belong to a hub, which could bring overall connection investment costs from EUR 83 billion to EUR 69 billion [227].

Afterwards, the project presented two possible offshore grid designs, namely the direct design and the split design. In the first design the offshore countries are connected directly via HVdc transmission lines and the OWFs hubs are connected onshore. In the split design, the OWFs are connected to the offshore network, which favours the development of a meshed North Sea transnational grid.

According to [227], the split design becomes more beneficial if the OWF distance to shore is higher than the distance between the offshore hubs. Additionally, to limit offshore transmission bottlenecks, the capacity between hubs should be kept lower than half the capacity between hubs and shores.

Solutions which have a meshed design have the benefit of increased N-1 security, as it was discussed in Section 3.5. Moreover, the project found the split design to be more cost-effective than the direct design solution based on a benefit-to-capex ratio. Ultimately, the offshore grid infrastructure cost would represent only a fifth of the possible revenues from the generated electricity [227]⁷.

⁷ Considering that offshore wind farms totalling 130 GW would generate circa 13000 TWh over 25 years, its market value would be 450 billion euros at an average spot price of EUR 50/MWh.

IEA Wind Task 25 (Sep. 2005 - 2014)

The IEA Wind Task 25, Power Systems with Large Amounts of Wind Power, is an international forum for best practices exchange regarding the integration of large-scale wind energy into power systems. The main focus is on technical-economic feasibility, inclusion into electricity markets, grid expansion costs, reliability, capacity credit; the assessment of technical constraints, such as grid stability and reserve requirements; and sharing information on used methods [228].

The first phase of IEA Task 25 finished in 2008 and the second phase finished in October 2011. In the Phase 1 final report the IEA Wind Task 25 recommends the transition towards a more flexible electricity grid, which includes management of generation and demand, larger balancing areas, more interconnection capacity, better integration of markets, and utilising the improved controllability of future wind power plants [228].

One of the project main results is a flow chart, shown in Figure A.6, which describes how to perform a complete wind integration study. According to the IEA Task 25, to allow higher penetrations of wind energy generation it is necessary to adapt power system practices by operating power plants in a more flexible way, straightening ac networks through connections to neighbouring countries and utilising demand-side management [229].

More information on IEA Task 25 project is available online at:
www.ieawind.org/task_25.html

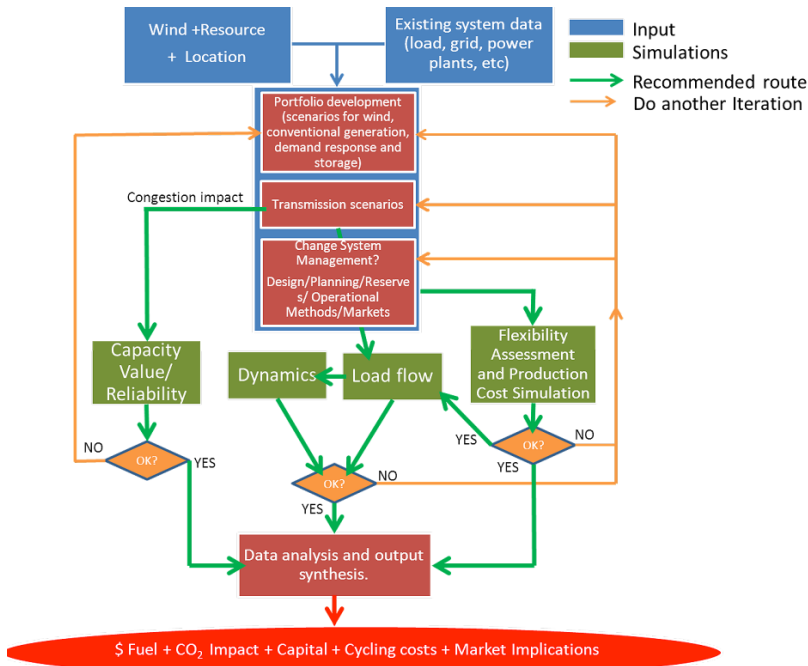


Figure A.6: IEA Task 25 flowchart on how to performed a complete wind integration study.

TWENTIES (2010 - Jun. 2013)

The TWENTIES project main goal was to research large-scale integration of wind power into the European power system via use of HVdc transmission systems. It involved 26 companies and research institutions from 10 European countries. The focus was on projects which demonstrate the feasibility of multi-terminal dc networks.

In this respect, French TSO RTE studied the technical feasibility of offshore MTdc grids, with particular focus on the operation and control during normal and contingency scenarios. Figure A.7 displays a picture of the dc cables used in the five-terminal MTdc setup built in the G2Elab in Grenoble, France [230].

The investigation included, among other matters, the development and testing of dc circuit breakers [231]. On March 21, 2013, in Alstom Grid Laboratory in Villeurbanne, France, a HVdc circuit-breaker prototype interrupted a direct current over 3 kA in less than 2.5 ms. Later in 2013, tests were scheduled to interrupt currents up to 7.5 kA under a direct voltage of 180 kV, as agreed in the project proposal [232]⁸.

Comparison to the NSTG Project

All projects surveyed anticipate that the European offshore wind energy capacity will be circa 70 GW by 2025. However, hitherto the offshore wind power installed capacity – 3.8 GW by the end of 2011 and 6.6 GW by the end of 2013 – is still small compared with the 117.3 GW installed capacity onshore by the end of 2013 [11].

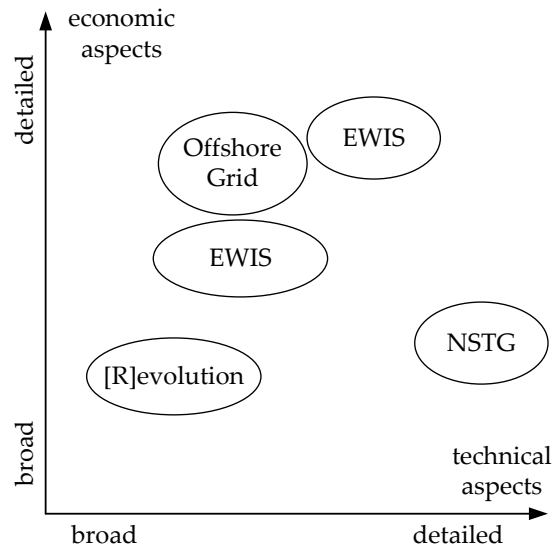
After describing the relevant offshore grid projects, it is then important to establish a comparison with the NSTG project on a regu-



Figure A.7: Picture showing the cable installations for the Twenties MTdc network.

⁸ More information on TWENTIES project is available online at:
<http://www.twenties-project.eu/node/1>

Figure A.9: Comparison between economic and technical aspects of different offshore grid projects.



⁹ More information on the North Sea Transnational Grid project is available online at: <http://www.nstg-project.nl/>

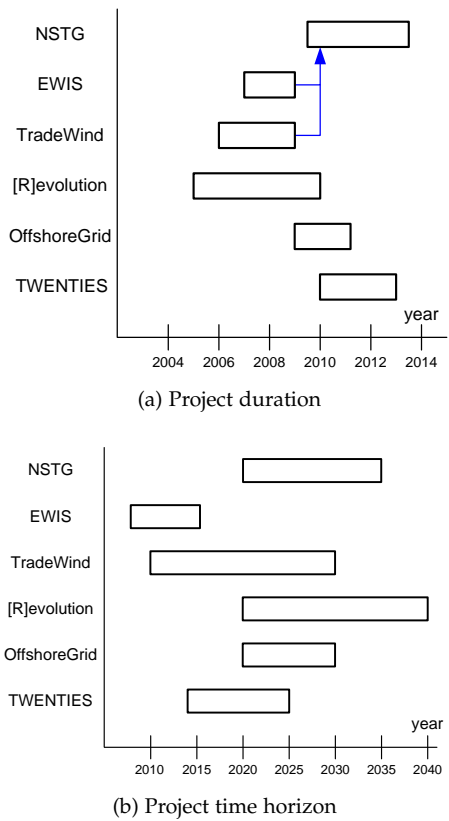


Figure A.8: Comparison of duration and time horizon of different offshore grid projects.

latory, economic, technical basis and time horizon [218].

In the NSTG-project the location and capacity of offshore wind farms installations up to 2030 were taken from previous studies as well as from the national construction plans of each North Sea country ⁹. Available wind speed distribution data were used for market analysis as well as for steady-state grid integration evaluation. The operation and control of MTdc networks was studied in detail and for protections aspects, dc circuit breakers were assumed to be available.

Figure A.8 displays a comparison of the duration and time horizon of the different offshore grid studies. With time, studies regarding the development of offshore wind farms and electrical infrastructure grew from a mere economical assessment toward a more thorough technical analysis. Figure A.9 offers a subjective comparison between economic and technical aspects of the different analysed offshore projects.

TradeWind emphasised the economic cost-benefit evaluation of wind integration by assessing cross-border power flows for future wind power capacity scenarios. Already planned grid reinforcements and HVdc inter-connectors were included. Then, three offshore topologies have been studied and their operating costs (particularly bottleneck) were studied by a flow-based power market simulator developed by SINTEF [221,222].

The EWIS project created a market model of the ENTSO-E grid showing where onshore transmission bottlenecks could arise, given selected landing points for offshore wind. The study pointed out the most critical grid reinforcements that should take place inside Europe to accommodate the predicted OWFs [223].

In its economic analysis, the [R]evolution study looked into capital expenditure of HVdc transmission systems and considered the dc network as a perfect copper plate. Other costs, such as operation and maintenance costs were not included [224,225].

The OffshoreGrid project focused on offshore grids steady-state operation with the same market simulator used in the TradeWind study. The project applied an iterative approach to determine the interaction between electricity markets, offshore grid design and operational costs. The main focus was on topology and cost optimisation rather than on technical aspects of the offshore grid network [185,226,227].

In the NSTG research project the costs and benefits of each grid solution were examined according to wind power generation data, investment cost figures as well as offshore transmission capacity. The market aspects of each scenario were studied according to an idealised market model in combination with a round the year load flow tool similar to the one in [233].

As the main intention of the NSTG project was to provide a technical blueprint, the focus was on design, operation and control of multi-terminal dc networks. This included steady-state behaviour as well as detailed dynamic modelling of the main components expected to be part of such transnational grid. Table A.1 summarises to what extent the surveyed projects treat different aspects regarding transnational offshore grids and how these relate to each other.

Table A.1: Research focus of different offshore grid projects.

	Market & Load Flow	Offshore Grid Design	Dynamic Stability	MTdc Control
TradeWind	+	+	-	-
EWIS	+	-	+	-
[R]evolution	+	+	-	-
OffshoreGrid	++	++	-	-
TWENTIES	-	+	++	+
NSTG	+	+	+	++

B

Additional Material

Philosophers are people who know less and less about more and more, until they know nothing about everything. Scientists are people who know more and more about less and less, until they know everything about nothing.

Konrad Lorenz

In this Appendix, additional material and results are presented for some of the thesis chapters.

B.1 Chapter 3

The Matlabcode to compute a multiple slack node dc load flow is given below. The first function loaded, *System_Data*, is the one which contains the system physical characteristics.

```
1 function system_data = System_Data(-)
2 % Build MTdc Network Model for Loadflow
3 % Author: Rodrigo Teixeira Pinto
4
5 %% System Data-----+
6 Vb_dc = 600e3;          %Base DC Voltage [V] (e.g. +- 300 kV)
7 Sb = 1000e6;            %Base Power [VA]
8 Zb_dc = Vb_dc^2/Sb;     %Base DC Impedance [Ohms]
9 Yb_dc = 1/Zb_dc;        %Base DC Admittance [S]
10 rdc = 2*0.023;         %Line Resistance [Ohms/m]
11
12 %% Define Here the Network model-----+
13 % Wind Farms according to NSTG WP2 Report (1GW = pu)
14
15 %Wind Farm      Country   Node    Size(pu)
16 %Doggersbank    UK        01      3
17 %Hornsea         UK        02      2
18 %Thorntonbank   Belgium   03      1
19 %IJmuiden        Netherl   04      2
20 %Eemshaven       Netherl   05      1
21 %Hochsee Sud     Germany   06      2
22 %Hochsee Nord    Germany   07      2
23 %Horns Rev       Denmark   08      1
24 %Ringkobing      Denmark   09      1
25
26 % 19 Lines / 19 nodes network
27 % Line Name — Nodes — Length
28 line(1,:)=[01 10 100]; line(2,:)=[02 10 040];
29 line(3,:)=[10 15 120]; line(4,:)=[10 11 300];
30 line(5,:)=[03 11 050]; line(6,:)=[11 16 100];
31 line(7,:)=[11 12 120]; line(8,:)=[04 12 100];
```

```

32 line(9,:)= [05 12 040]; line(10,:)= [12 17 070];
33 line(11,:)= [12 13 250]; line(12,:)= [06 13 040];
34 line(13,:)= [07 13 070]; line(14,:)= [13 18 150];
35 line(15,:)= [13 14 120]; line(16,:)= [08 14 40];
36 line(17,:)= [09 14 50]; line(18,:)= [14 19 150];
37 line(19,:)= [10 14 380];
38
39 % For Incidence Matrix
40 % B = number of nodes (buses) L = number of lines
41 B = max(max(line(:,1:2))); L = length(line(:,1));
42
43 %% Generated & consumed Power in the Nodes (dimension = ...
44 B)-+
45 % Generated & consumed Power in the Nodes (dimension = B)
46 % Modify Pg and Pc accordingly
47 % Pg >(<) 0: Power Entering (Exiting) Node
48 % Pc <(>) 0: Power Entering (Exiting) Node
49
50 %Initialization
51 Pg=zeros(1,B); Pc=zeros(1,B);
52
53 %UK WF - Doggersbank / Hornsea / Grid
54 Pg(1)=3; Pg(2)=2; %Pg(15)=-5;
55
56 %Belgium WF - Thorntonbank / Grid
57 Pg(3)=1; %Pg(16)=-1;
58
59 %Netherlands WF - Ijmuiden / Eemshaven / Grid
60 Pg(4)=2; Pg(5)=1; %Pg(17)=-3;
61
62 %Germany WF - Hochsee Sud / Nord / Grid
63 Pg(6)=2; Pg(7)=2; %Pg(18)=4;
64
65 %Denmark WF - Horns Rev / Ringkobing / Grid
66 Pg(8)=1; Pg(9)=1; %Pg(19)=-2;
67
68 Pg = Pg*0.75;
69 V_ini = ones(B,1);
70 sn = 15:19; %Select slack nodes
71
72 %% Generate Incidence Matrix -----+
73 [IM,d_line] = IncidenceMatrix(L,B,line);
74
75 Rdc = rdc*d_line; %Line resistance [Ohm]
76 rdc_pu = Rdc/Zb_dc; %Line resistance [pu]
77
78 %% Generate Ybus (Y in Thesis Text)-----+
79 % Primitive Yp matrix (Line Impedances) Dimension (L x L)
80 Yp = eye(L,L).*repmat(1./rdc_pu,1,L);
81 % Calculate Ybus matrix -> dimension (B x B)
82 IM_t = transpose(IM);
83 Ybus = IM_t * Yp * IM;
84
85 %% Output System Data-----+
86 system_data.Sb = Sb;
87 system_data.Vb_dc = Vb_dc;
88 system_data.Zb_dc = Zb_dc;
89 system_data.Yb_dc = Yb_dc;
90 system_data.B = B;
91 system_data.L = L;
92 system_data.line = line;
93 system_data.d_line = d_line;
94 system_data.IM = IM;
95 system_data.IM_t = IM_t;
96 system_data.Yp = Yp;
97 system_data.Ybus = Ybus;
98 system_data.Rdc = Rdc;
99 system_data.rdc_pu = rdc_pu;

```

```

99 system_data.Pc = Pc;
100 system_data.Pg = Pg;
101 system_data.V_ini = V_ini;
102 system_data.sn = sn;
103 end

```

The *System_Data* function calls the *IncidenceMatrix* function to generate the MTdc network incidence matrix automatically from the *line* vector.

```

1 function [IM,d_line] = IncidenceMatrix(L,B,line)
2 % Build Incidence Matrix
3 % Each row of IM is one transmission line
4 % Departing node = 1 , Arriving node = -1 , 0 otherwise.
5 %-----+
6 IM=zeros(L,B);
7 IM((line(:,1)-1)*L+(1:L)') = 1;
8 IM((line(:,2)-1)*L+(1:L)') = -1;
9 d_line=line(:,3);
10 end

```

The multiple slack node dc load flow is a function, *Loadflow*, which can be called in Matlab as: $g = \text{Loadflow}(\text{System_Data})$;

```

1 function loadflow = Loadflow(system_data)
2 % Steady-State Calculations of the MTDC in the NSTG Project
3 % Author: Rodrigo Teixeira Pinto
4
5 %% Begin Load Flow-----+
6 % Declaration of initial variables from system_data struct
7 V_ini = system_data.V_ini;
8 IM = system_data.IM;
9 Yp = system_data.Yp;
10 Ybus = system_data.Ybus;
11 Pg = system_data.Pg;
12 Pc = system_data.Pc;
13 sn = system_data.sn;
14 B = system_data.B;
15 L = system_data.L;
16
17 % Calculation of initial Mismatch terms
18 fp=Mismatch(V_ini,Ybus,B,Pg,Pc,sn);
19 % Construction of the Initial Jacobian Matrix
20 J=JMatrix(V_ini,Ybus,B,sn);
21 J_inv = inv(J);
22 % load-flow tolerance
23 eps = 1e-12;
24 % iteration number
25 n=1;
26 % Initialization of voltage Δ vector
27 dV_slack = zeros(B,1);
28 % Initialization of voltage vector
29 V = V_ini;
30
31 while max(abs(fp))>eps
32     % Construction of the new iteration ...
33     (dx(k)=-J^-1(k)*f(k));
34     dV = -J_inv*fp;
35
36     % augment dV inserting dV@slack nodes = 0
37     j=0;
38     k=1:B;
39     k(sn)=[];
40     dV_slack(k)=dV;

```

```

40     V = V+dV_slack;
41
42     % Construction of the new Jacobian Matrix
43     J=JMatrix(V,Ybus,B,sn);
44     J_inv = inv(J);
45
46     % Calculation of new Mismatch terms
47     fp=Mismatch(V,Ybus,B,Pg,Pc,sn);
48
49     n=n++1;
50
51     if n≥100
52         break;
53     end
54 end
55
56 %% Verify Load Flow Results—————+
57 I_node = Ybus*V;
58 if sum(I_node)<eps
59     flag='load flow ok sum(I_node)=0';
60 else
61     flag='load flow not ok sum(I_node)>0';
62 end
63
64 P_node = V.*I_node;
65 P_losses = sum(P_node);
66 dV = IM*V;
67 I_line = dV.*sum(Yp)';
68 P_losses_line = (I_line'.^2/Yp)';
69 P_line = repmat(I_line,1,B).*repmat(V,1,L)'.*IM;
70
71 %% Output Load Flow —————+
72 loadflow.V = V';
73 loadflow.I_node = I_node';
74 loadflow.P_node = P_node';
75 loadflow.P_losses = P_losses;
76 loadflow.I_line = I_line';
77 loadflow.P_line = P_line;
78 loadflow.P_losses = P_losses;
79 loadflow.P_losses_line = P_losses_line';
80 loadflow.sn = sn;
81 loadflow.flag = flag;
82 end

```

To run, the *Loadflow* function calls the *Mismatch* and *JMatrix* functions, which compute, respectively, the load flow equations mismatch terms and the MTdc network Jacobian matrix.

```

1 function fp = Mismatch(V,Ybus,B,Pg,Pc,sn)
2 %% Calculate the Load Flow Equations Mismatch—————+
3 fp = V*V'*Ybus;
4 % The mismatch terms are in the diagonal
5 fp = fp.*eye(B);
6 fp = sum(fp);
7
8 fp = (Pg - Pc - fp)';
9 % Here lies the trick!
10 % Clean mismatch function taking the slack nodes values out
11 fp(sn,:)=[];
12 end

```

```

1 function J = JMatrix(V,Ybus,B,sn)
2 % V: vector of Direct Voltages
3 % Ybus: Admittance Matrix

```

```

4 % B: number of buses
5 % ns: number of desired slacks
6 VB = repmat(V,1,B);
7 J1 = VB.*Ybus;
8 J2 = repmat(sum(J1)',1,B).*eye(B);
9 J = - J1 - J2;
10 J(sn,:)=[];
11 J(:,sn)=[];
12
13 % The .m files for other algorithms, e.g. the N-1 security
14 % algorithm or the DVC strategy can be obtained by writing
15 % to rodrigo.t.p@gmail.com.
16 end
    
```

B.2 Chapter 5

As the MTdc network dynamic model developed in Chapter 4 has several different signals available, one of the main challenges when presenting results was to select which signal to show. In total, the model of each voltage-source converter has 13 dc-related variables, and 50 ac-related variables. A list of the monitored variables is shown in Table B.1 and Table B.2.

As this thesis focus is on the MTdc network, most case studies presented the resulting direct voltage and the active power at important dc grid nodes. It might be interesting, however, to also look at the current and voltages at the ac network. Therefore, the current and voltages of the two voltage controlling converter stations (VSC1 and VSC2) for the case studied analysed in Chapter 5, are displayed in Figure B.1 to Figure B.4.

The voltages and currents are presented in the (dq) rotating frame, on the left-hand side, and in the (abc) three-phase frame on the right-hand side of the graphics. It is interesting to note that the rotating frame result provides more information on the active and reactive components of the ac network currents and voltages, whether the results in the three-phase frame seem to provide only information about the module of the voltages and currents. That is why the ac variables in the thesis have been presented in module or in the rotating frame.

Regarding the results shown in Figure B.1 to Figure B.4, they confirm what was already concluded from the analysis of the MTdc network voltage and active power: i.e. the droop control and ratio control strategy had the best dynamic performance amongst the compared MTdc control methods, whereas the voltage margin method had the worst performance.

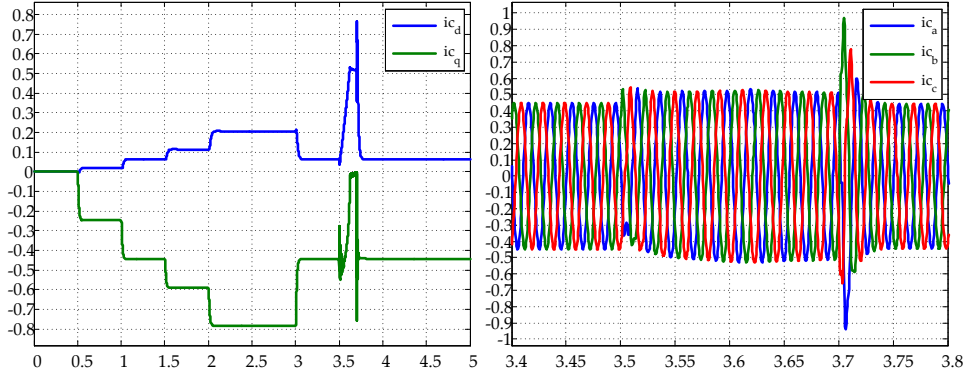
For instance, during the fault, between $3.5 \leq t \leq 3.7$ s, the ac grid voltage at VSC2 seem be more disturbed with the voltage margin method than with the other control methods.

Table B.1: DC signals in the VSC dynamic model.

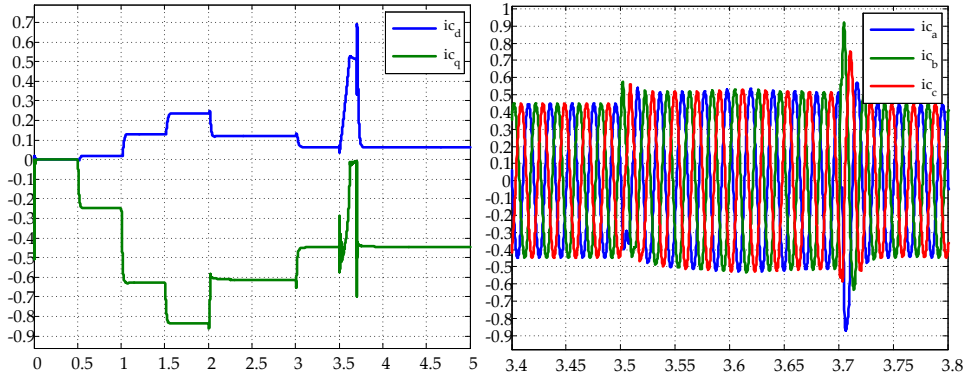
Signal Number	Symbol
1	W_{dc}
2	W_{dc}^*
3	V_{dc}
4	P_{dc}
5	$P_{chopper}$
6	P_{cable}
7	P_{cap}
8	P_L
9	I_{dc}
10	$I_{chopper}$
11	I_{cable}
12	I_{cap}
13	I_L

Table B.2: AC signals in the VSC dynamic model.

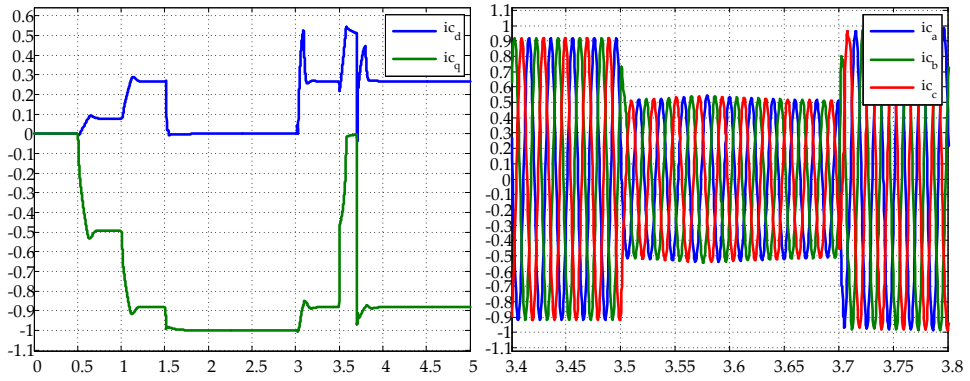
Signal Number	Symbol
1	w
2-3	e_{dq}^g
4-5	e_{dq}^c
6	$ e_{dq}^g $
7	$ e_{dq}^c $
8-9	u_{dq}^g
10	$ u_{dq}^g $
11-12	e_{dq}^{g*}
13	$ e_{dq}^{g*} $
14-15	$ v_{dq}^c $
16-17	$ v_{dq}^{c*} $
18	$ v_{dq}^c $
19-20	m_a^{dq}
21-22	m_{lim}^{dq}
23-24	i_{dq}^g
25	$ i_{dq}^g $
26-27	i_{dq}^c
28	$ i_{dc}^c $
29-30	i_{fdq}^c
31	$ i_{fdq}^c $
32-33	i_{cdq}^c
34-35	i_{cdq}^{c*}
36	$ i_{cdq}^c $
37-39	P_{ac}, Q_{ac}, S_{ac}
40-42	P_g, Q_g, S_g
43-45	P_f, Q_f, S_f
46-48	P_c, Q_c, S_{vsc}
49-50	P_{ac}^*, Q_{ac}^*



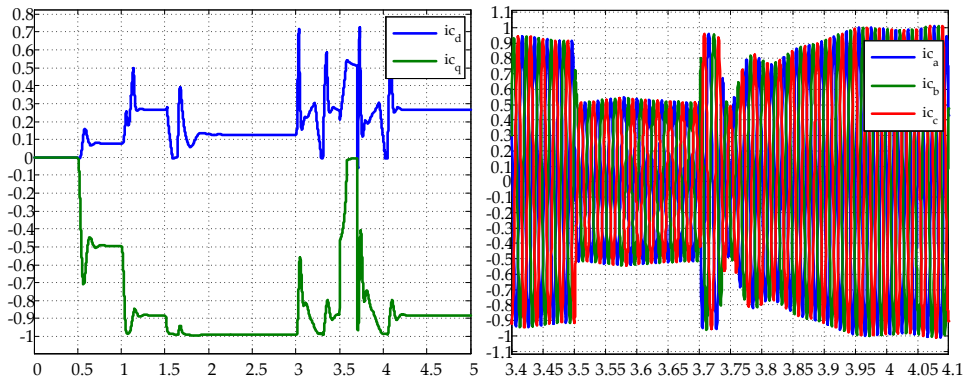
(a) droop control strategy



(b) ratio control strategy

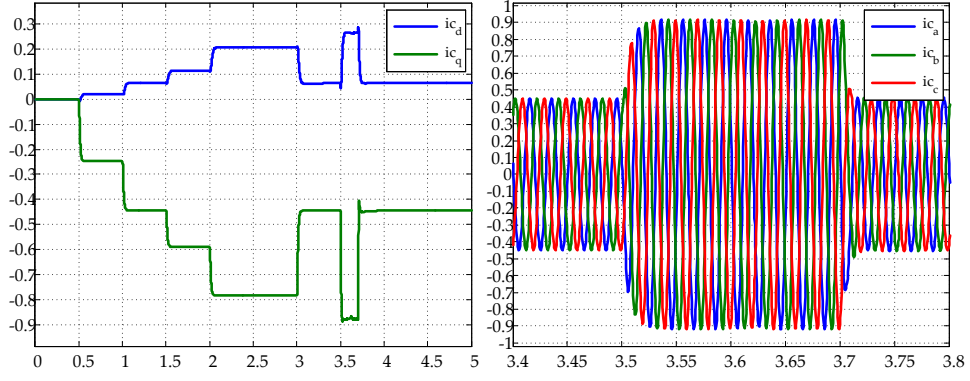


(c) priority control strategy

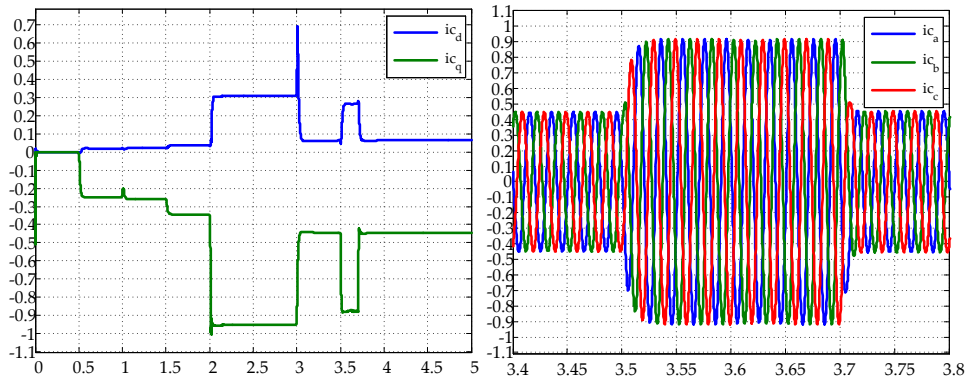


(d) voltage margin method control strategy

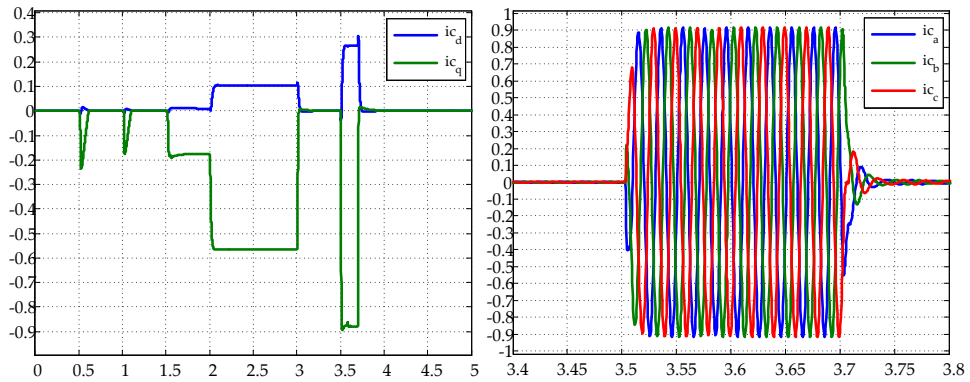
Figure B.1: Currents of VSC1 in (dq) and (abc) frame for the different direct voltage control strategies.



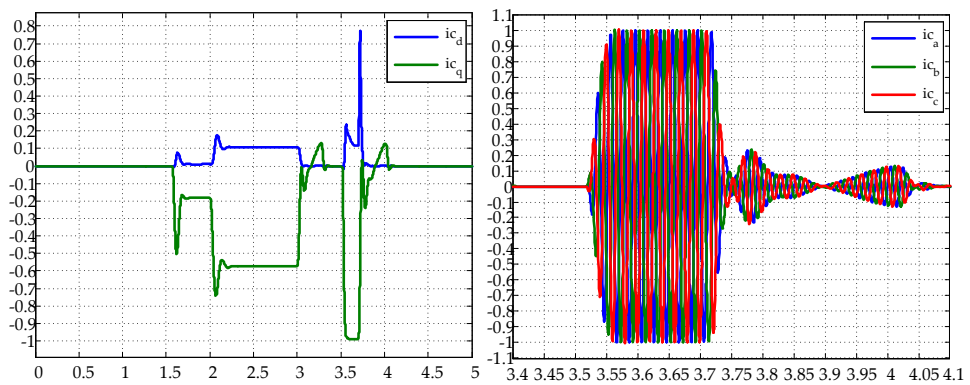
(a) droop control strategy



(b) ratio control strategy

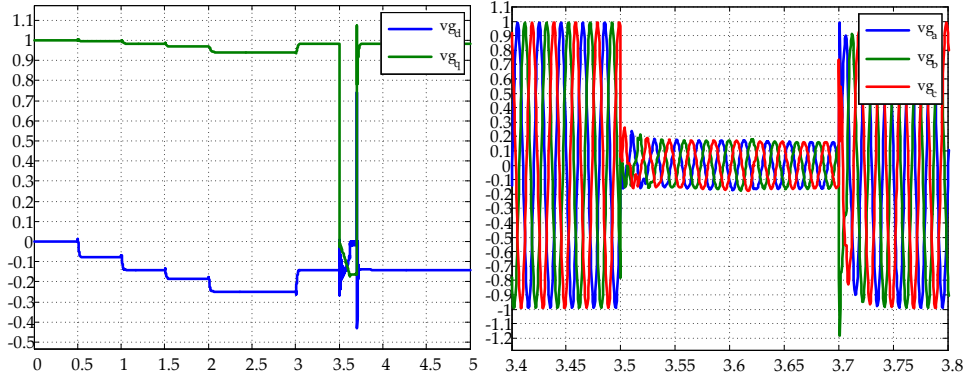


(c) priority control strategy

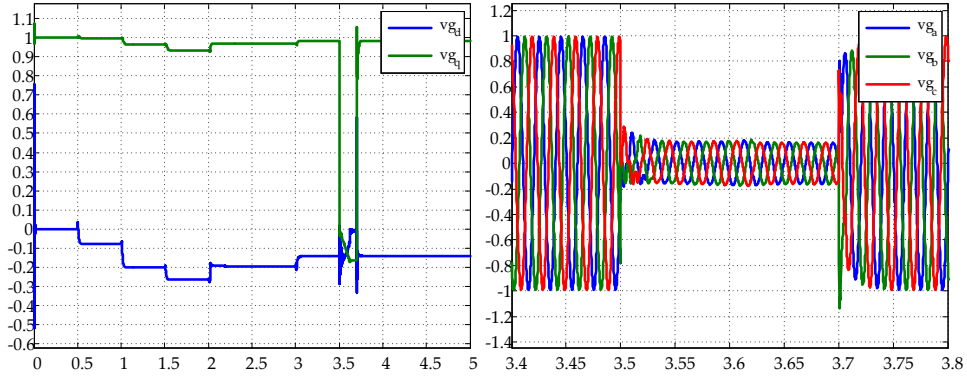


(d) voltage margin method control strategy

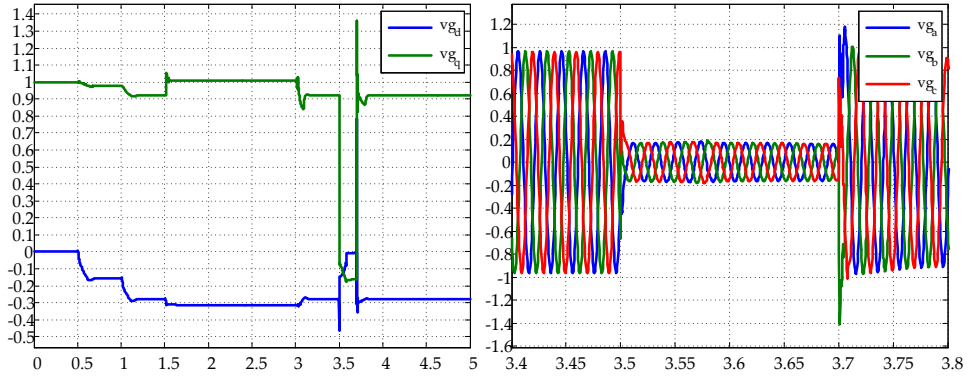
 Figure B.2: Currents of VSC2 in (dq) and (abc) frame for the different direct voltage control strategies.



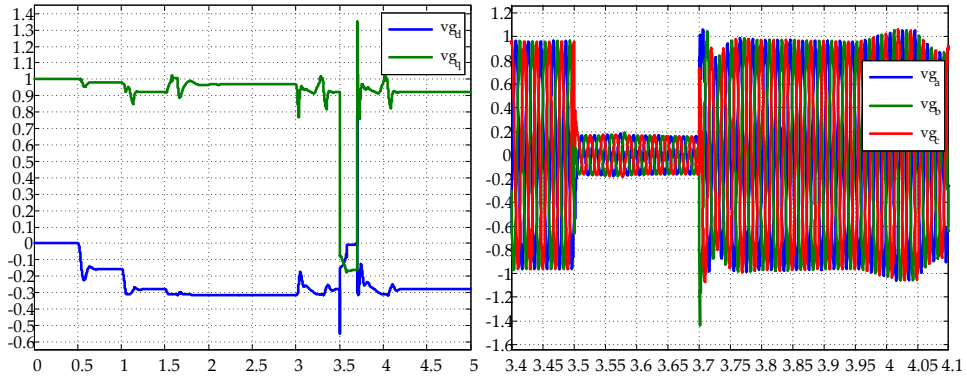
(a) droop control strategy



(b) ratio control strategy

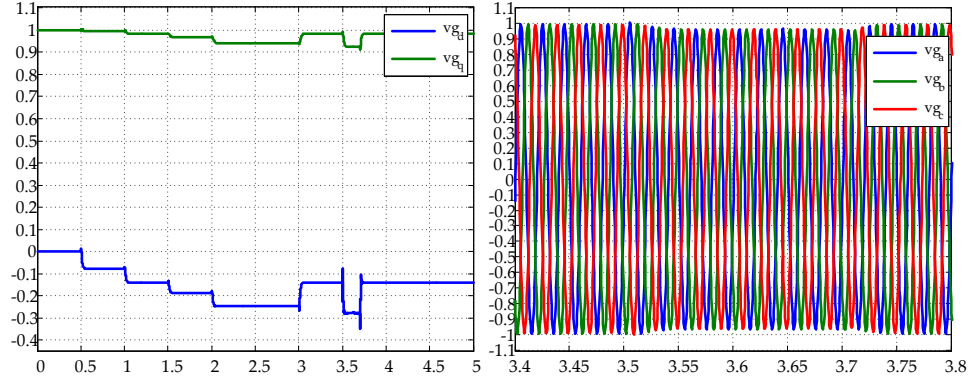


(c) priority control strategy

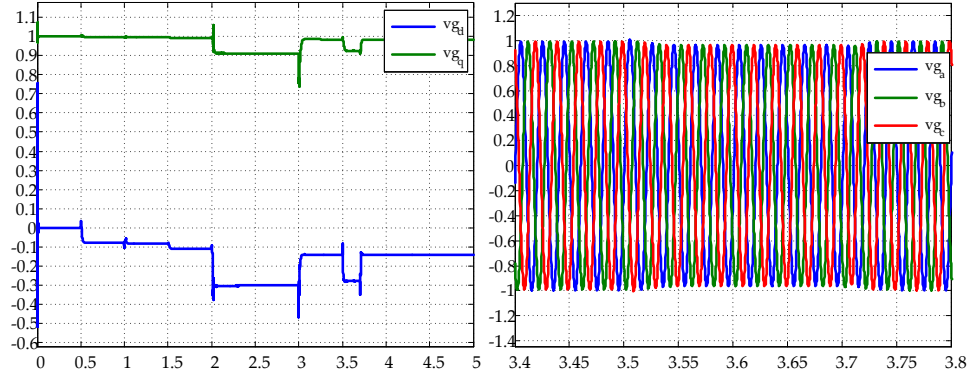


(d) voltage margin method control strategy

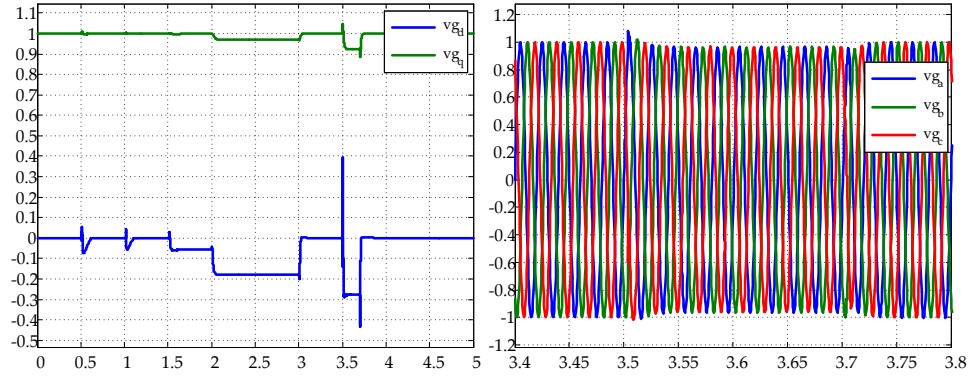
Figure B.3: Grid 1 voltage at PCC in (dq) and (abc) frame for the different direct voltage control strategies.



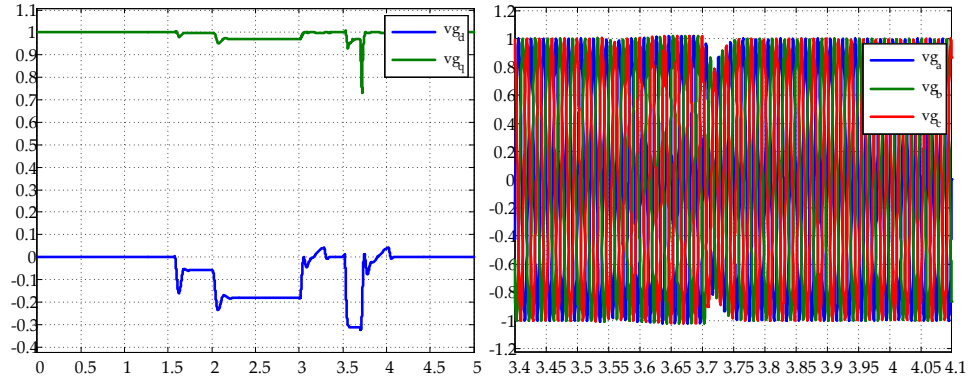
(a) droop control strategy



(b) ratio control strategy



(c) priority control strategy



(d) voltage margin method control strategy

 Figure B.4: Grid 2 voltage at PCC in (dq) and (abc) frame for the different direct voltage control strategies.

B.3 Chapter 8

In Chapter 8, a small-signal model of a voltage-source converter was presented. The complete model is expressed from equations (8.13) until (8.31). Expanding these equations as a function of the state and input variables, respectively, the state matrix, \mathbf{A} , and the input matrix, \mathbf{B} , can be obtained.

The state matrix, \mathbf{A} , is given as:

$$\mathbf{A} = \begin{bmatrix} -\frac{R_g}{L_g} & w_0 & a_{1,3} & a_{1,4} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & I_{q0}^g K_i^{pll} & a_{1,13} \\ -w_0 & -\frac{R_g}{L_g} & a_{2,2} & a_{2,3} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{I_{d0}^g L_c K_i^{pll}}{L_g} & a_{2,13} \\ \frac{1}{C_f} & 0 & a_{3,3} & a_{3,4} & -\frac{\cos(\theta_0)}{C_f} & \frac{\sin(\theta_0)}{C_f} & 0 & 0 & 0 & 0 & 0 & U_{q0}^g K_i^{pll} & a_{3,13} \\ 0 & \frac{1}{C_f} & a_{4,3} & U_{d0}^g K_p^{pll} \sin(\theta_0) & -\frac{\sin(\theta_0)}{C_f} & -\frac{\cos(\theta_0)}{C_f} & 0 & 0 & 0 & 0 & 0 & -U_{d0}^g K_i^{pll} & a_{4,13} \\ -\frac{E_{q0}^g K_p k_q^Q}{L_c} & \frac{E_{d0}^g K_p k_q^Q}{L_c} & 0 & 0 & -\frac{(R_c + k_p)}{L_c} & 0 & \frac{k_i}{L_c} & 0 & 0 & 0 & \frac{K_i^Q k_p}{L_c} & 0 & 0 \\ 0 & 0 & 0 & 0 & -w_0 & -\frac{(R_c + k_p - L_c w_0)}{L_c} & 0 & \frac{k_i}{L_c} & -\frac{K_p K_i^W}{L_c} & \frac{K_i^W k_p}{L_c} & 0 & 0 & 0 \\ -E_{q0}^g k_q^Q & E_{d0}^g k_q^Q & 0 & 0 & -1 & 0 & 0 & 0 & 0 & 0 & K_i^Q & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & -1 & 0 & 0 & -K_p^W & K_i^W & 0 & 0 & 0 \\ \frac{2E_{q0}^g I_{d0}^c K_p k_q^Q}{C_{dc}} & -\frac{2E_{d0}^g I_{q0}^c K_p k_q^Q}{C_{dc}} & a_{9,3} & a_{9,4} & \frac{2(V_{d0}^c + I_{d0}^c k_p)}{C_{dc}} & a_{9,5} & \frac{2I_{d0}^c k_i}{C_{dc}} & \frac{2I_{q0}^c k_i}{C_{dc}} & \frac{2I_{q0}^c K_p K_i^W}{C_{dc}} & -\frac{2I_{d0}^c K_i^W k_p}{C_{dc}} & \frac{2I_{d0}^c K_i^Q k_p}{C_{dc}} & 0 & a_{9,13} \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -1 & 0 & 0 & 0 & 0 \\ -E_{q0}^g & E_{d0}^g & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & -\cos(\theta_0) & -\sin(\theta_0) & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & a_{12,13} \\ 0 & 0 & -K_p^{pll} \cos(\theta_0) & -K_p^{pll} \sin(\theta_0) & 0 & 0 & 0 & 0 & 0 & 0 & 0 & K_i^{pll} & a_{13,13} \end{bmatrix} \quad (\text{B.1})$$

where;

$$a_{1,3} = -\left(I_{q0}^g L_g K_p^{pll} \cos(\theta_0) + 1\right) / L_g$$

$$a_{1,4} = -I_{q0}^g K_p^{pll} \sin(\theta_0)$$

$$a_{1,13} = -I_{q0}^g K_p^{pll} \left(U_{q0}^g \cos(\theta_0) - U_{d0}^g \sin(\theta_0)\right)$$

$$a_{2,2} = I_{d0}^g L_c K_p^{pll} \cos(\theta_0) / L_g$$

$$a_{2,3} = (I_{d0}^g L_c K_p^{pll} \sin(\theta_0) - 1) / L_g$$

$$a_{2,13} = I_{d0}^g L_c K_p^{pll} \left(U_{q0}^g \cos(\theta_0) - U_{d0}^g \sin(\theta_0)\right) / L_g$$

$$a_{3,3} = -U_{q0}^g K_p^{pll} \cos(\theta_0)$$

$$a_{3,4} = w_0 - U_{q0}^g K_p^{pll} \sin(\theta_0)$$

$$a_{3,13} = \left[I_{q0}^c \cos(\theta_0) + I_{d0}^c \sin(\theta_0) - C_f U_{q0}^g K_p^{pll} \left(U_{q0}^g \cos(\theta_0) - U_{d0}^g \sin(\theta_0)\right)\right] / C_f$$

$$a_{4,3} = -\left(w_0 - U_{d0}^g K_p^{pll} \cos(\theta_0)\right)$$

$$a_{4,13} = \left[I_{q0}^c \sin(\theta_0) - I_{d0}^c \cos(\theta_0) + C_f U_{d0}^g K_p^{pll} \left(U_{q0}^g \cos(\theta_0) - U_{d0}^g \sin(\theta_0)\right)\right] / C_f$$

$$a_{9,3} = (2/C_{dc}) \left(I_{d0}^c \left(\cos(\theta_0) - I_{q0}^c L_c K_p^{pll} \cos(\theta_0)\right) - I_{q0}^c \left(\sin(\theta_0) - I_{d0}^c L_c K_p^{pll} \cos(\theta_0)\right)\right)$$

$$a_{9,4} = (2/C_{dc}) \left(I_{q0}^c \left(\cos(\theta_0) + I_{d0}^c L_c K_p^{pll} \sin(\theta_0)\right) + I_{d0}^c \left(\sin(\theta_0) - I_{q0}^c L_c K_p^{pll} \sin(\theta_0)\right)\right)$$

$$a_{9,5} = (2/C_{dc}) \left(V_{q0}^c + I_{q0}^c (k_p - L_c w_0) + I_{d0}^c L_c w_0\right)$$

$$a_{9,13} = -(1/C_{dc}) \left[I_{d0}^c \left(U_{d0}^g \sin(\theta_0) - U_{q0}^g \cos(\theta_0) + I_{q0}^c L_c K_p^{pll} \left(U_{q0}^g \cos(\theta_0) - U_{d0}^g \sin(\theta_0)\right)\right)\right]$$

$$+ (2/C_{dc}) \left[I_{q0}^c \left(U_{d0}^g \cos(\theta_0) + U_{q0}^g \sin(\theta_0) - I_{d0}^c L_c K_p^{pll} \left(U_{q0}^g \cos(\theta_0) - U_{d0}^g \sin(\theta_0)\right)\right)\right]$$

$$a_{12,13} = U_{d0}^g \sin(\theta_0) - U_{q0}^g \cos(\theta_0)$$

$$a_{13,13} = -K_p^{pll} \left(U_{q0}^g \cos(\theta_0) - U_{d0}^g \sin(\theta_0)\right)$$

On the other hand, the input matrix, \mathbf{B} , is written as:

$$\mathbf{B} = \begin{bmatrix} \frac{1}{L_g} & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{L_g} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ \frac{I_{q0}^g K_p K_p^Q}{L_c} & -\frac{I_{d0}^g K_p K_p^Q}{L_c} & 0 & 0 & \frac{K_p K_p^Q}{L_c} & 0 \\ 0 & 0 & 0 & \frac{K_p K_p^W}{L_c} & 0 & 0 \\ I_{q0}^g K_p^Q & -I_{d0}^g K_p^Q & 0 & 0 & K_p^Q & 0 \\ 0 & 0 & 0 & K_p^W & 0 & 0 \\ -\frac{2I_{d0}^c I_{q0}^g K_p K_p^Q}{C_{dc}} & \frac{2I_{d0}^c I_{q0}^g K_p K_p^Q}{C_{dc}} & -\frac{2}{C_{dc}} & -\frac{2I_{q0}^c K_p K_p^W}{C_{dc}} & -\frac{2I_{d0}^c K_p K_p^Q}{C_{dc}} & 0 \\ 0 & 0 & 0 & 1 & 0 & 0 \\ I_{q0}^g & -I_{d0}^g & 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \end{bmatrix} \quad (\text{B.2})$$

Using the VSC state-matrix presented given in (B.1), it was possible to show how the VSC eigenvalues locations, show in Figure 8.11, varied with changes in the VSC components values, such as the phase reactor or the dc-side capacitor. The changes in the eigenvalues location with variation of the VSC components were presented in Chapter 8 in Figure 8.17 and Figure 8.18.

C

A Short History of Electricity Developments

We live in a society exquisitely dependent on science and technology, in which hardly anyone knows anything about science and technology.

Carl Sagan.

The word *electricity*, first coined by William Gilbert, is derived from the Greek word for amber (*elektron*), given its ability to attract other materials, by electrostatic forces, when rubbed [234]. The ancient Greek, as well as the early Chinese from 1000 A.D., already knew about the existence of lodestones – which are natural magnetites – and its magnetic properties. However, modern history of electricity and magnetism is considered to have started only in 1600, when William Gilbert published “*De Magnete*”, where he studied the behaviour of compass needles and proposed the Earth was a giant magnet [234].

Figure C.1 shows the electrostatic generator from Otto von Guericke, invented in 1660, which is the first device which can be called an electricity generator. Figure C.2 shows Alessandro Volta’s pile, the first usable dc battery, invented only in 1800. Figure C.3 and Figure C.4 display a timeline showing some of the most important discoveries in the history of dc and ac electricity until the end of the XIXth century. For a century after the “*De Magnete*” publication, electricity stayed more of a curiosity than a science.

XVIIth Century

The history of electricity discoveries started with direct current. The first electricity generator, invented around 1660 by German engineer Otto von Guericke, consisted of a sulphur sphere mounted on a wooden structure, where it rotated by means of a crank [38]. The electrostatic electricity was generated by friction between the sulphur sphere and a cloth glove or dry hands (See Figure C.1). The electrostatic generator from Guericke made it possible, for the first time in history, to generate higher amounts of electricity. The news of his invention spread throughout Europe and increased the interest in this new science.



Figure C.1: Otto von Guericke electrostatic generator



Figure C.2: Alessandro Volta pile, the first direct current battery.

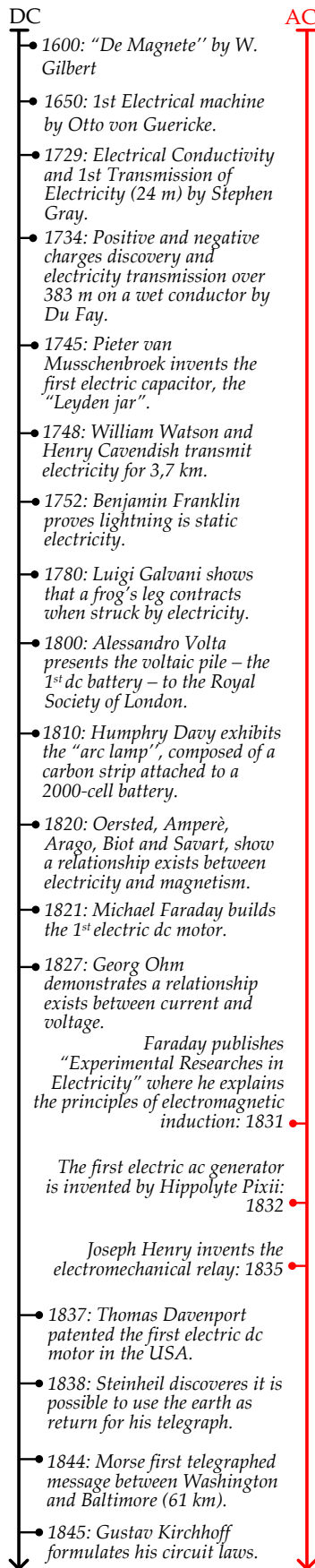


Figure C.3: Electricity development timeline (continues in Figure C.4)

XVIIIth Century

In the XVIIIth century, the focus of the experiments seems to have changed from electricity generation to its transmission. In 1734, French chemist Charles Du Fay discovered the existence of positive and negative charges and managed to transmit electricity over 383 m [38]. The first electric accumulator, or condenser, was invented by Dutch scientist Pieter van Musschenbroek from Leiden and came to be known as the "Leyden jar". Using one of these devices, William Watson and Henry Cavendish successfully managed to transmit electricity for circa 3.7 km. Their goal was to measure the electricity transmission speed, which they concluded was instantaneous [38].

Other important experiments were performed in the XVIIIth century, such as the ones from Benjamin Franklin and Luigi Galvani. It was a century of electricity discoveries related to direct current which culminated, in 1800, with the presentation of the first battery by Alessandro Volta at the Royal Society in London (see Figure C.2).

XIXth Century

In the beginning of the XIXth century, different scientists such as Hans Christian Ørsted and André-Marie Ampère, had started to show there was a link between electricity and magnetism, as the first appeared to cause the latter and vice-versa [234].

Nevertheless, it was not until 1831, when Michael Faraday characterised magnetic induction, that the principles for alternating current (ac) electricity were laid. The work of Faraday led to the ac revolution and the development, decades later, of the ac transformer and the ac electric motor. Actually, the first ac electric generator was invented only a year later, in 1832, by French instrument maker Hippolyte Pixii; who afterwards, following a suggestion from Ampère, added a commutator to the generator design, transforming it into a dc generator, probably due to lack of ac applications [38].

The first half of the XIXth century saw the birth of the alternating current, significant improvements to dc generators (also known as dynamos), the development of the telegraph technology, and the beginning of electricity and magnetism integration, which was completed in 1865, when James Clerk Maxwell published "A Dynamical Theory of the Electromagnetic Field" [235]. Maxwell unification of electric and magnetic phenomena as being a manifestation of the same theory, the electromagnetic field, is deemed as the second great unification in physics; after the one performed earlier by Isaac Newton with the uncovering of the gravitational field [236].

Nevertheless, dc technology was still predominant. In 1876, Charles Brush, an American inventor, was issued a patent for his arc lighting system. The system made use of an improved dc generator, the open-coil dynamo, also known as the Brush dynamo [38]. Only three years later, two Brush dynamos were delivering power to 22 arc lamps for the newly formed California Electric Light Company.

In that same year, 1879, another American inventor, Thomas Alva

Edison, presented his version of the electric lamp in an event in New York. The business for electric light systems was developing fast and, in 1880, Edison patented the first system for the distribution of electricity. Two years later, in 1882, he opened the first electric central station – using his bipolar dc generators – in Pearl Street, New York. By 1884, the Pearl Street power plant was providing dc electricity for lightning around 10 thousand lamps from 508 different consumers [237].

Nonetheless, in the end of the XIXth century, after more than two and a half centuries of dc predominance, the situation started to change in favor of ac technology. In less than a decade, during the 1880s, the ac generator, the ac transformer and the ac motor were developed and perfected using the magnetic induction principles set by Faraday and Maxwell.

The first ac transmission line (circa 30 km long) was built in Italy in 1886; it used the Ganz system which comprised a high-efficiency transformer developed earlier, in 1884, by Hungarian engineers Károly Zipernowsky, Ottó Bláthy and Miksa Déri (known as the ZBD team) [18,19]. In 1888, working independently, Galileo Ferraris and Nikola Tesla developed ac induction motors and the stage for ac electricity predominance was complete [38].

Furthermore, in 1888, Nikola Tesla demonstrated the first complete “polyphase” ac electrical system, which included all elements necessary for electricity generation, transmission and utilisation: an electrical generator, transformers, the transmission system cables, the induction motor, and electric light bulbs. In May 16, 1888 Tesla presented his famous paper “*A New System of Alternating Current Motors and Transformers*” which he introduced at the American Institute of Electrical Engineers. In July 1888, George Westinghouse, the head of Westinghouse Electric Company, bought the patent rights to the ac polyphase system [38].

It is not clear in which year the war of the currents ended, however, it is clear that 1888 was the turning point in which the victory of ac over dc started.

At that time, dc transmission systems were proved inefficient when compared to its ac counterpart. Using cheap, simple and sturdy transformers, alternating voltages could be stepped up for transmission, and stepped down for distribution and utilisation. On the other hand, low-voltage dc transmission, due to high losses and elevated voltage drops, forced Edison to build generating plants near load centres; whereas most of the potential sites for exploring hydroelectricity were distant from load centres [238].

Indeed, in 1890, a single-phase ac system – long 21 km and operating at 4 kV – was chosen for the first hydroelectric power transmission in the USA, from the Willamette Falls to Portland [19]. The first long-distance ac transmission took place in Germany in 1891, where electricity was transmitted for 177 km at 8 kV, between Lauffen and Frankfurt [38].

In 1892, General Electric was formed and, against Edison’s views,

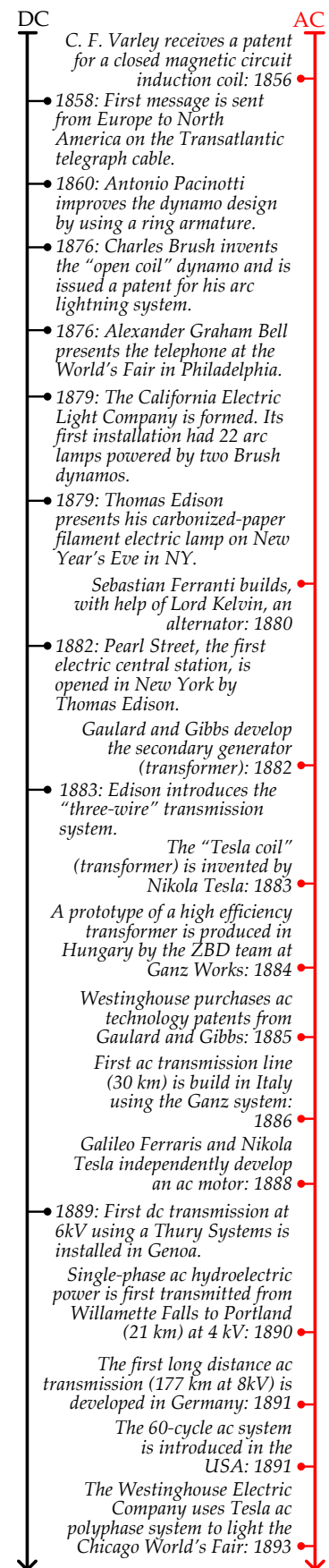


Figure C.4: Electricity development timeline [38].

it invested considerably in ac technology. In 1893, the Westinghouse Electric Company, using Tesla's ac polyphase system, won the rights to power the Chicago World Fair. In 1895, Westinghouse Company won a contract for the Niagara Falls Adams Power Plant – which transmitted ac electricity over 35 km to Buffalo – bidding half as much as Edison did for the installation of a dc transmission system [38].

In fact, only two decades after the war of the currents ended, by the 1910s, there were more than fifty ac transmission systems in service, operating with voltage ratings from 70 to 150 kV [239] and ac technology came out as the winner in the first war of the currents.

Nowadays, as presented in Chapter 2, there are circa 140 high-voltage direct current transmission systems worldwide, yet, only a minute number, exactly three of them, are multi-terminal networks. Perhaps the development of high-voltage multi-terminal direct current networks can start to change the status quo towards direct current. Let us only hope that it will not take another century before dc systems rival ac systems in number of projects, because in terms of transmission voltage, distance and power capacity dc already surpassed ac with flying colours.

Abbreviations

ac Alternating current

ACSR Aluminium-conductor steel-reinforced

ADC Analog-digital converter

BE Belgium

CSC Current-source converter

CTL Cascated Two Level

dc Direct current

DE Germany

DFIG Doubly-fed Induction Generators

DN Denmark

dq Direct-quadrature

DVC Distributed Voltage Control

ECN Energy Research Centre of the Netherlands

EMI Electromagnetic Interference

ENTSO-e European Network of Transmission System Operators for electricity

EU European Union

EWIS European Wind Integration Study

FACTS Flexible AC Transmission Systems

FRT Fault-ride through

GA Genetic Algorithm

GCR Grid Code Requirements

GIS Gas-Insulated Switchgear

GTO Gate turn-off thyristor

HV-MTdc high-voltage multi-terminal direct current

HVac High-voltage alternating current

HVdc High-voltage direct current

ICC Inner-current Controller

IEA International Energy Agency

IEE Intelligent Energy Europe

IGBT Insulated-gate bipolar transistor

IGCT Integrated gate-commutated thyristors

LCC Line-commutated converter

LV-MTdc Low-voltage multi-terminal direct current

LVdc Low-voltage direct current

LVRT Low-voltage ride through

MMC Modular Multilevel Converter

MOGA Multi-Objective Genetic Algorithm

MTdc Multi-terminal direct current

MTU Maximum Transmission Unit

MVdc Medium-voltage direct current

NL The Netherlands

NPC Neutral point clamped

NSCOGI North Seas Countries Offshore Grid Initiative

NSTG North Sea Transnational Grid

OHL Overhead lines

OPF Optimal power flow

OWEZ Egmond aan Zee offshore wind farm

OWF Offshore Wind Farm

PCC Point-of-Common Coupling

PF Power Factor

<i>PI</i>	Proportional-integral
<i>PLL</i>	Phase-locked loop
<i>PMSG</i>	Permanent-magnet Synchronous Generator
<i>PTC</i>	Positive Temperature Coefficient
<i>pu</i>	Per unit
<i>PWM</i>	Pulse-Width Modulation
<i>RMS</i>	Root mean square
<i>ROW</i>	Right of way
<i>SCADA</i>	Supervisory Control and Data Acquisition
<i>SCIG</i>	Squirrel-cage Induction Generator
<i>SCR</i>	Short-Circuit ratio
<i>SCR</i>	Silicon-controlled rectifier
<i>SIL</i>	Surge Impedance Loading
<i>SSM</i>	Small-Signal Model
<i>STATCOM</i>	Static Synchronous Compensator
<i>SVC</i>	Static VAr Compensator
<i>SVPWM</i>	Space-vector Pulse-Width Modulation
<i>TSO</i>	Transmission System Operator
<i>UFS</i>	Ultra-fast switch
<i>UHVdc</i>	Ultra high-voltage direct current
<i>UK</i>	The United Kingdom
<i>UN</i>	United Nations
<i>VMM</i>	Voltage Margin Method
<i>VSAT</i>	Very Small Aperture Terminal
<i>VSC</i>	Voltage-source converter
<i>WP</i>	Work package

List of Symbols

A	state matrix	
A_{co}	transformer core area	[m ²]
A_{cu}	transformer window area	[m ²]
A_{dc}	dc cable cross-section	[mm ²]
A_r	wind turbine rotor area	[m ²]
Aug_{Fit}	chromosome augmented fitness value	
α	transformer voltage ratio	
$\alpha_c \mid \alpha_c^{pu}$	ICC closed-loop bandwidth	[rad/s] ∣ [pu]
$\alpha_{dc} \mid \alpha_{dc}^{pu}$	direct voltage controller bandwidth	[rad/s] ∣ [pu]
$\alpha_p \mid \alpha_p^{pu}$	active power controller bandwidth	[rad/s] ∣ [pu]
$\alpha_q \mid \alpha_q^{pu}$	reactive power controller bandwidth	[rad/s] ∣ [pu]
$\alpha_v \mid \alpha_v^{pu}$	ac network voltage controller bandwidth	[rad/s] ∣ [pu]
B	input matrix	
B_{ij}	admittance matrix susceptance at position ij	[S]
β	function of the wind turbine pitch angle	[rad]
C	output matrix	
c	ac transmission line per-unit length capacitance	[F/km]
C_b	ac system base capacitor	[F]
$C_{dc} \mid c_{dc}$	VSC dc output capacitor	[F] ∣ [pu]
c_c	dc cable per unit-length capacitor	[F/km]
C_{dcj}	sum of all capacitances at MTdc network node j	[F]
C_f	LCL-filter capacitor	[F]
Co	cost	[m.u.]
$\cos\phi$	ac system power factor	
D	feed-foward matrix	
d	transmission distance or line length	[m]
δ	load angle	[rad]
δ_i	switching function for phase i	
E	ac system phase voltage	[V]
e	voltage at the ac line sending node or ac network voltage	[pu]
\bar{e}_{dq}	ac network voltage phasor in the (dq) rotating frame	[V]
$e_d \mid e_q$	ac network voltage in the d-axis ∣ q-axis	[V]
e_{dq}^g	ac grid voltage in the grid (dq) frame	[V]

E_{dq0}^g	ac grid steady-state voltage in the grid rotating frame	[V]
e_{dq}^g	ac grid small-signal voltage in the grid rotating frame	[V]
$\left \bar{e}_{dq} \right $	ac network voltage controller phasor amplitude	[V]
$\left \bar{e}_{dq}^* \right $	ac network voltage controller reference phasor amplitude	[V]
E_L	ac system line-to-line voltage	[V]
ε	error	
$\tilde{\varepsilon}_{dc}$	direct voltage controller small-signal error	[Vs]
$\dot{\tilde{\varepsilon}}_{dc}$	direct voltage controller small-signal error derivative	[V]
ε_g	load flow percentage error	[%]
$\tilde{\varepsilon}_{id}$	ICC d-axis controller small-signal error	[As]
$\dot{\tilde{\varepsilon}}_{id}$	ICC d-axis controller small-signal error derivative	[A]
$\tilde{\varepsilon}_{iq}$	ICC q-axis controller small-signal error	[As]
$\dot{\tilde{\varepsilon}}_{iq}$	ICC q-axis controller small-signal error derivative	[A]
$\tilde{\varepsilon}_{pll}$	PLL controller small-signal error	[Vs]
$\dot{\tilde{\varepsilon}}_{pll}$	PLL controller small-signal error derivative	[V]
$\tilde{\varepsilon}_Q$	reactive power controller small-signal error	[VAr s]
$\dot{\tilde{\varepsilon}}_Q$	reactive power controller small-signal error derivative	[VAr]
f	ac network frequency	[Hz]
$\varphi_{\hat{B}}$	peak magnetic flux	[Wb]
f^{lim}	frequency upon which curtailment should start	[Hz]
$f(\mathbf{x}, \mathbf{U})$	OPF function to be optimised	
\mathbf{g}	mismatch vector	[VA]
$\mathbf{g_P}$	active power mismatch vector	[W]
G_f	active power curtailment slope	[W/Hz]
G_{ij}	admittance matrix conductance at position ij	[S]
G_p	active power gradient	[W/s]
g_{P_i}	active power mismatch at node i	[W]
g_{Q_i}	reactive power mismatch at node i	[VAr]
H	synchronous machine inertia constant	[s]
$\mathbf{I_M}$	incidence matrix	
I_{ac}	alternating current	[A]
I_b	ac system base current	[A]
I_c	current through the VSC output dc capacitor	[A]
I_{cdq0}^c	VSC steady-state current in the VSC rotating frame	[A]
i_{cdq}^{*c}	VSC small-signal current reference in the VSC rotating frame	[A]
i_{cdq}^c	VSC small-signal current in the VSC rotating frame	[A]
i_{cdq}^g	VSC small-signal current in the grid rotating frame	[A]
$i_d i_q$	current in the d-axis q-axis	[A]
$I_{dc} i_{dc}$	direct current	[A] [pu]
\bar{i}_{dq}	current phasor in the rotating frame	[A]
i_{dq}^g	grid current in the grid (dq) frame	[A]
I_{dq0}^g	grid steady-state current in the grid rotating frame	[A]
i_{dq}^g	grid small-signal current in the grid rotating frame	[A]

\dot{i}_{dq}^g	grid small-signal current derivative in the grid rotating frame	[A]
$i_d^* i_q^*$	VSC inner-current controller d-axis reference q-axis reference	[A]
I_L	current flowing into the MTdc network	[A]
I_{Li}	current flowing through line i	[A]
I_{Mij}	MTdc network incidence matrix ij -th position	
I_n	nominal current	[A]
\bar{i}_{sdq}	PMSG stator current in the rotating frame	[A]
\bar{i}_{sdq}^*	PMSG stator current reference in the rotating frame	[A]
i_x	active part of the ac network current	[A]
i_y	reactive part of the ac network current	[A]
J	jacobian matrix	
j	imaginary unit matrix representation	
J	moment of inertia	[kg m ²]
J	winding current density	[A/m ²]
k	averaged period number	
$K_p^V k_p^v$	ac network voltage controller proportional gain	[A/V] [pu]
$K_i^V k_i^v$	ac network voltage controller integral gain	[A/Vs] [pu]
$K_i^P k_i^p$	active power controller integral gain	[A/Ws] [pu]
$K_p^P k_p^p$	active power controller proportional gain	[A/W] [pu]
$K_p^W k_p^w$	direct voltage controller proportional gain	[V ²] [pu]
$K_i^W k_i^w$	direct voltage controller integral gain	[V ² /s] [pu]
$K_p k_p$	ICC proportional gain	[Ω] [pu]
$K_i k_i$	ICC integral gain	[Ω/s] [pu]
K_p^{pll}	PLL controller proportional gain	[rad/Vs]
K_i^{pll}	PLL controller integral gain	[rad/Vs ²]
K_p^s	PMSG speed controller proportional gain	[rad/s/Nm]
K_i^s	PMSG speed controller integral gain	[rad/s ² /Nm]
$K_p^Q k_p^q$	reactive power controller proportional gain	[A/VAr] [pu]
$K_i^Q k_i^q$	reactive power controller integral gain	[A/VAr s] [pu]
L	lagrangian function	
L	information frame size	[bits]
L	number of dc lines in the MTdc network	
L	Inductance	[H]
l	ac transmission line per-unit length inductance	[H/km]
L_c	phase reactor inductance	[H]
l_{dc}	dc cable per-unit length inductance	[H/km]
L_{dci}	inductance of MTdc line i	[H]
L_{eq}	PMSG equivalent inductance	[H]
L_g	grid-side inductance	[H]
L_s	PMSG stator winding self-inductance	[H]
L_σ	PMSG stator winding dispersed inductance	[H]
$L_T l_T$	total inductance between the VSC and the ac network	[H] [pu]
λ	vector of the lagrangian multipliers	
λ	state-matrix eigenvalues	

λ	wind turbine tip speed ratio	
$\bar{\lambda}_{dq}$	PMSG flux in the rotating frame	[Wb]
$\bar{\lambda}_{mdq}$	permanent magnet flux in the rotating frame	[m/s]
M	mass	[kg]
m_a	VSC modulation index	
Max_{Const}	value of the highest constraint violation	
M_i	i-th penalty function	
m_i	i-th penalty factor	
M_{Vi}	i-th node direct voltage penalty function	
m_{Vi}	i-th node direct voltage penalty factor	
N	number of nodes in the MTdc network	
n	number of information frames to be transmitted	
p	system poles	[rad/s]
$P_{ac} \mid p_{ac}$	Active power in the ac system	[W] [pu]
$\bar{p}_{acj}^{vsc}(k)$	average active power at ac grid side of converter j	[W]
$p_{acj}^{vsc}(t)$	measured instantaneous active power at ac grid side of converter j	[W]
$P_{ac}^{owf} \mid p_{ac}^{owf}$	active power at the OWF ac side	[W] [pu]
$P_{ac}^* \mid p_{ac}^*$	active power reference at the ac-grid side	[W] [pu]
$P_c \mid p_c$	VSC active power at the ac side	[W] [pu]
$\tilde{P}_c \mid \tilde{p}_c$	the VSC small-signal active power	[W] [pu]
P_d	power density	[VA/kg]
$P_{dc} \mid p_{dc}$	Active power in the dc system	[W] [pu]
P_{dcj}^{owf}	active power injected at the j-th OWF	[W]
P_{dcj}^{vsc}	active power of the j-th VSC	[W]
P_{Gi}	active power generation at node i	[W]
$P_{Idc}^i(t)$	instantaneous active power of the i-th VSC terminal operating in current regulation mode	[VA]
$p_{inv}^{lim} \mid p_{rec}^{lim}$	VSC active power limit as inverter rectifier	[pu]
$P_L \mid p_L$	power flowing into the MTdc network	[W] [pu]
P_{Li}	active power load at node i	[W]
$P_{losses} \mid p_{losses}$	power losses power losses relative to the rated power	[W] [pu]
$p_{losses}^{\%}$	MTdc network losses as a function of the total generated power at the OWFs	[%]
$\bar{p}_{losses}(k)$	average MTdc network losses in period k	[W]
\tilde{P}_L	small-signal active power flowing into the dc line	[W]
P_m	wind turbine mechanical power	[W]
P_n	dc cable rated power	[W]
P_{trade}	power trade being traded in the MTdc network	[W]
$P_{Vdc}^{max}(t)$	instantaneous maximum active power of the N-th VSC controlling the dc system voltage	[VA]
ΔP_{ac}	required active power curtailment	[W]
$Q_{ac} \mid q_{ac}$	reactive power in the ac system	[VAr] [pu]
$Q_{ac}^* \mid q_{ac}^*$	reactive power reference at the ac-grid side	[VAr] [pu]

$Q_c \mid q_c$	VSC reactive power at the ac side	[VAR] [pu]
$Q_f \mid q_f$	LCL-filter reactive power	[VAR] [pu]
$Q_g \mid q_g$	reactive power at the ac grid side	[VAR] [pu]
Q_{G_i}	reactive power generation at node i	[VAR]
\tilde{q}_g	small-signal reactive power at the ac grid side	[VAR]
Q_l	inductive reactive power	[VAR]
Q_{L_i}	reactive power load at node i	[VAR]
R	information transmission rate	[bps]
r	ac transmission line per-unit length resistance	[Ω/km] or [pu/km]
$R_c \mid r_c$	phase reactor resistance	[Ω] [pu]
r_{dc}	dc cable per-unit length resistance	[Ω/km] or [pu/km]
R_{dci}	resistance of MTdc network line i	[Ω]
$R_g \mid r_g$	grid-side inductance	[Ω] [pu]
R_s	PMSG stator resistance	[Ω]
$R_T \mid r_T$	Total resistance between the VSC and the ac network	[Ω] [pu]
S_{ac}	ac network apparent power	[VA]
S_b	ac system base power	[VA]
S_f	LCL-filter size	[VA]
S_k	ac network short-circuit power	[VA]
S_n	rated apparent power	[W]
S_{vsc}	VSC apparent power	[VA]
T	total time to transmit information data package	[s]
t	time	[s]
t_{ack}	time for the receiver to acknowledge data delivery	[s]
T	averaging period	[s]
t_b	dc circuit breaker interruption time	[s]
t_{ctr}	VSC protection controller delay	[s]
t_d	selective fault detection method time to signal the fault	[s]
T_e	PMSG electric torque	[Nm]
t_{end}	total experiment time	[s]
T_e^*	PMSG electric torque reference	[Nm]
T_f	time to send the frame and receive the delivery acknowledgement	[s]
t_{fault}	total time to realise and isolate a fault	[s]
t_{frame}	time needed to transmit one information frame	[s]
$t_{(I_0 \rightarrow 2pu)}$	VSC current time to surpass the overcurrent threshold value	[s]
t_l	transmission line transport delay	[s]
T_m	PMSG mechanical torque	[Nm]
t_{proc1}	time for the optimisation algorithm to solve the OPF	[s]
t_{proc2}	time for the DVC controller to set the onshore VSC voltage to the received reference set-point	[s]
t_{prop1}	propagation time between the OWF and the TSO control centre	[s]
t_{prop2}	propagation time between the TSO control centre and onshore VSC	[s]
t_{vsc}	VSC overcurrent protection trigger time	[s]
τ	VSC inertia constant	[s]

$\tilde{\theta}$	PLL small-signal angle (i.e. angle between the grid and the converter (dq) rotating frames)	[rad]
θ_0	initial PLL angle	[rad/s]
$\dot{\tilde{\theta}}$	PLL small-signal angle derivative	[rad/s]
\mathbf{U}	OPF control variables vector	
\mathbf{u}	input vector	
$\tilde{\mathbf{u}}$	small-signal changes in the input variables	
\mathbf{U}^0	control vector initial value	
\mathbf{U}_0	steady-state input variables	
$u_{dq}^{\tilde{c}}$	LCL-filter small-signal voltage in the VSC rotating frame	[V]
u_{dq}^s	LCL-filter voltage in the grid (dq) frame	[V]
U_{dq0}^s	LCL-filter steady-state voltage in the grid rotating frame	[V]
u_{dq}^s	LCL-filter small-signal voltage in the grid rotating frame	[V]
U_f	LCL-filter capacitor phase voltage	[V]
U_i^{k+1}	i -th control variable at iteration $k + 1$	
$U_i^{\max} \mid U_i^{\min}$	i -th control maximum value \mid minimum value	
\mathbf{U}^{k+1}	new control vector value	
v	propagation speed	[m/s]
v	voltage at the ac line receiving node or VSC ac-side voltage	[pu]
V_b	ac system base voltage	[V]
V_c	VSC ac-side voltage	[V]
V_{dq0}^c	VSC steady-state voltage in the VSC rotating frame	[V]
v_{ci}	modulated VSC phase i voltage ($i = a, b, c$)	[V]
\hat{V}^{max}	VSC maximum single-phase peak voltage	[V]
$v_d \mid v_q$	VSC d-axis voltage \mid q-axis voltage	[V]
$V_{dc} \mid v_{dc}$	VSC direct voltage output	[V] \mid [pu]
v_{dc}^0	initial direct voltage	[pu]
V_{dcb}	dc system base voltage	[V]
\mathbf{V}_{dc}	MTdc network voltage vector	[V]
V_{dci}	MTdc network voltage at node i	[V]
V_{dci}^{lim}	limit of the i -th node direct voltage	[V]
V_{dci}^*	i -th MTdc node direct voltage reference	[V]
V_{dc}^{max}	maximum allowable direct voltage level	[V]
$v_{dc}^{max} \mid v_{dc}^{min}$	maximum \mid minimum allowable direct voltage	[pu]
$v_{dc}^{*high} \mid v_{dc}^{*low}$	higher \mid lower direct voltage reference	[pu]
\bar{v}_{dq}	VSC voltage phasor in the rotating frame	[V]
$v_{dq}(k + 1)$	VSC ac-side voltage at time-step $k + 1$	[V]
$v_{dq}^{\tilde{c}}$	VSC small-signal voltage reference in the VSC rotating frame	[V]
$v_{dq}^{\tilde{c}}$	VSC small-signal voltage in the VSC rotating frame	[V]
$v_{dq}^*(k)$	VSC reference voltage at time-step k	[V]
V_i	ac system voltage at node i	[V]
V_o	analog signal voltage	[V]
V_o	volume	[m ³]
V_{owf}	OWF collection voltage	[V]
\bar{v}_{sdq}	PMSG stator voltage in the rotating frame	[V]

V_w	average wind speed	[m/s]
$V_w(t)$	undisturbed wind speed	[m/s]
W	OPF fixed variables vector	
W_c	VSC dc capacitor stored energy	[J]
$W_{dc} \mid w_{dc}$	square of the VSC direct voltage	[V ²][pu]
w_{dc}^0	initial VSC direct voltage value squared	[pu]
$W_{dc}^* \mid w_{dc}^*$	square of the VSC direct voltage reference	[V ²][pu]
$\tilde{\omega}$	grid small-signal angular frequency	[rad/s]
ω_{sw}	VSC angular switching frequency	[rad/s]
ω	ac system angular frequency	[rad/s]
ω_b	ac system base angular frequency	[rad/s]
ω_r	PMSG rotor speed	[rad/s]
ω_r^*	PMSG rotor speed reference	[rad/s]
ω_s	VSC control sampling frequency	[rad/s]
X	inductance	[Ω]
x	state variable vector	
\tilde{x}	small-signal changes in the state variables	
X_0	steady-state state variables	
x	ac transmission line per-unit length inductive reactance	[Ω/km]
X_c	ac transmission line per-unit length capacitive reactance	[Ω/km]
\dot{x}	state variable derivatives vector	
X_f	LCL-filter capacitive reactance	[Ω]
x_i	i-th i-th state variable	
$X_T \mid x_T$	total reactance between the VSC and the ac grid	[Ω] [pu]
Y	MTdc network admittance matrix	[S]
\tilde{y}	small-signal changes in the output variables	
y	output vector	
Y_0	steady-state output variables	
Y_{ij}	admittance matrix value at position ij	[S]
Y_p	MTdc network primitive admittance matrix	[S]
z	OPF specified variables vector	
$Z_c \mid z_c$	VSC phase reactor impedance	[Ω] [pu]
Z_{cc}	ac network short-circuit impedance	[Ω]
z_{dc}	DC cable impedance	[Ω/km]
Z_s	ac transmission line surge impedance	[Ω]
$Z_t \mid z_t$	transformer impedance	[Ω] [pu]

List of Publications

Journal Publications

1. R. Teixeira Pinto, S. F. Rodrigues, P. Bauer, and J. Pierik, "Description and Comparison of DC Voltage Control Strategies for Offshore MTdc Networks: Steady-State and Fault Analysis," *European Power Electronics Journal*, vol. 22, no. 4, pp. 13–21, 2013.
2. R. Teixeira Pinto, P. Bauer, S. Rodrigues, E. Wiggelinkhuizen, J. Pierik, and B. Ferreira, "A Novel Distributed Direct-Voltage Control Strategy for Grid Integration of Offshore Wind Energy Systems Through MTdc Network," *IEEE Transactions on Industrial Electronics*, vol. 60, no. 6, pp. 2429–2441, June 2013.
3. R. Teixeira Pinto, S. F. Rodrigues, E. Wiggelinkhuizen, R. Scherrer, P. Bauer, and J. Pierik, "Operation and Power Flow Control of Multi-Terminal DC Networks for Grid Integration of Offshore Wind Farms Using Genetic Algorithms," *Energies*, vol. 6, no. 1, pp. 1–26, 2012. [Online]. Available: <http://www.mdpi.com/1996-1073/6/1/1>
4. S. Rodrigues, R. Teixeira Pinto, P. Bauer, and J. Pierik, "Optimal Power Flow Control of VSC-based Multi-Terminal DC Network for Offshore Wind Integration in the North Sea," *IEEE Journal of Emerging and Selected Topics in Power Electronics - Early Access*, vol. PP, no. 99, pp. 1–9, 2013. [Online]. Available: <http://ieeexplore.ieee.org/arnumber=6600728>
5. E. Kontos, R. Teixeira Pinto, S. F. Rodrigues, and P. Bauer, "Impact of HVDC Transmission System Topology on Multi-Terminal DC Network Faults," *Submitted to IEEE Transactions on Energy Delivery on October 14th 2013.*, vol. PP, pp. 1–8, 2013.

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1. A. A. van der Meer, R. Teixeira Pinto, M. Gibescu, P. Bauer, J. Pierik, F. Nieuwenhout, R. Hendriks, W. Kling, and G. van Kuik, "Offshore Transnational Grids in Europe: the North Sea Transnational Grid Research Project In Relation To Other Research Initiatives," *Proceedings of the 9th International Workshop on Large-Scale Integration of Wind Power Into Power Systems As Well As On Transmission Networks For Offshore Wind Power Plants*, Quebec, Canada, October 2010.
2. R. Teixeira Pinto and P. Bauer, "Modular Dynamic Models of Large Offshore Multi-Terminal DC (MTdc) Networks," *Proceedings of the European Wind Energy Association Conference*, Brussels, Belgium, March 2011, pp. 1–10.
3. R. Teixeira Pinto and P. Bauer, "The Role of Modularity Inside the North Sea Transnational Grid Project: Modular Concepts for the Construction and Operation of Large Offshore Grids," *Proceedings of the Renewable Energy World Europe Conference*, Milan, Italy, June 2011, pp. 1–19.

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6. S. Lazarou, E. Wiggelinkhuizen, R. Pinto, P. Minnebo, H. Wilkening, J. Pierik, and G. Fulli, "A Smart Grid Simulation Centre at the Institute for Energy and Transport – Integration of Large Amounts of Offshore Wind Energy," in *Complexity in Engineering (COMPENG)*, Aachen, Germany, June 2012, pp. 1–6.
7. S. Rodrigues, R. Teixeira Pinto, P. Bauer, E. Wiggelinkhuizen, and J. Pierik, "Optimal power flow of VSC-based multi-terminal DC networks using genetic algorithm optimization," in *IEEE Energy Conversion Congress and Exposition (ECCE)*, Raleigh, USA, sept. 2012, pp. 1453–1460.
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11. B. Elizondo, R. Teixeira Pinto, and P. Bauer, "Sustainable DC-Microgrid Control System for Electric-Vehicle Charging Stations," in *Proceedings of the 2013-15th European Conference on Power Electronics and Applications (EPE 2013)*, Lille, France, sept. 2013, pp. 1–10.
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⁴ Although I suspect today she meant a M.D., not really a Ph.D.!

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⁸ Tip for future Ph.D. fellows: if you have a meeting with Prof. Bauer and have not prepared much, just ask him something about the invasion of Normandy. I am positively sure the meeting will be over before he has any chance of realising you did not do much this week!

⁹ But sometimes unfair!

¹⁰ Thank you very much Prof. Ferreira for your time and for all the meetings we had, in which most of them I left with more questions than answers. It took me some time to realise that that is when real science happens!

¹¹ Additionally, I will hold dear in my memory all the long trips to ECN. Those two and a half hours (one way!) travelling through the Netherlands always allowed me valuable time to think about the project, and the work ahead of us. And the time spent with you, and Edwin, in ECN was always very productive. Dear Jan, I wish you all the best for your retirement, I believe that you more than deserved it! You'll be missed! Additionally, I want to thank very much Edwin for all his support with the modelling, simulating and writing. I hope our collaboration will only grow in the future. Also many thanks to the JRC colleagues, Stavros, Gianluca, Heinz, Philip, José and Carlo, for their support to this work.

¹² The interaction with other academics, and industry experts, is one of the greatest pillars of Science and Engineering. Hence, I am most grateful to Prof. Thiringer, Prof. Kling, Prof. van der Meijden and Prof. Smit.

¹³ Unfortunately this space is limited, so I cannot spell out all the names, but I can try!

¹⁴ Also, thank you very much for trying to teach me Portuguese: És um gajo bué fixe pá! Valeu Tuga!

¹⁵ Additionally, thanks for all the marvelous Greek food, although I think I should actually be thanking Renata, so here it goes, thank you Renata! And also thanks for all the gifts!

¹⁶ First you Pavel, thanks for all the "just stop by for coffee" and always organising a lot of events around the World! Also thanks for introducing Camilo to us! Johan, thanks for all the "one beer only" nights out, and sorry for trying to attack you. And please say thank you to Taryn for all the lovely cards and finely selected wine bottles! Marcelo, thanks for all the events you helped to organise in the group, and the talks we had when you stayed in my place, I really miss them. Camilo, thank you for being so good with navigating small alleys, I am glad we are family now.

¹⁷ Dear Xun, you always had kind words to encourage me, thank you so very much, they really meant a lot to me! Please extend my gratitude to Mei as well. Todor, I have to say I really enjoyed most of our discussions about almost everything. You are a very knowledgeable person, thanks for sharing and thank you for all the really tight bear-like hugs, in the beginning I did not like them very much, but I have to say they grew on me with the years! Carlos, thank you very much for your support with preparing high-quality pictures, and for the nice work you did in our lab!

¹⁸ Jokes aside, I really enjoy talking to you, and I admire your wit and abilities with Matlab!

¹⁹ But also for hosting Francesca and I in Hungary, for introducing us to Hélen – *Egészségedre!* – and also for taking one for the common good.

²⁰ As a final remark, I would like to thank my friends in Brazil (specially Ricardo for the collaboration) and in Italy, and the Professors I had during my studies in these two countries because, generally, without a good bachelor and master degree, one cannot obtain a Ph.D. title.

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Curriculum Vitae

Rodrigo Teixeira Pinto was born in São Paulo, Brazil, on November 3rd, 1983. In 2003 he joined the Escola Politécnica da Universidade de São Paulo for a bachelor in Electrical Engineering at the Electrical Energy and Automation (PEA) department. In 2006 he started his Msc. in Electrical Engineering at the Politecnico di Torino, in Turin, Italy. From May to November 2008 he was with Siemens PTI, in Erlangen, Germany, working towards his MSEC. as a Diplomand on the Network Dynamics Studies department. On December 2008 he received his MSc. (cum laude) from the Politecnico di Torino. From February to July 2009 he was an intern consultant at the energy consultant company A&C, in Brazil. From December 2009 until March 2014, he worked as a PhD researcher on the North Sea Transnational Grid project at the Electrical Sustainable Energy Faculty (ESE) of Delft University of Technology.

