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System Design
and
Balancing Control
of the
North Sea Super Grid

Thesis for the degree of Philosophiae Doctor

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Abstract

The construction of the North Sea Super Grid is the major step towards meeting the future demand for electric power transmission in northern Europe. This grid will likely also extend onshore towards the load centres, and eventually form the European Super Grid.

Large-scale electric power generation at remote locations will lead to significant long distance power flows with a preferred flow direction. A method to identify these unidirectional flows has been developed and applied on a case study, indicating the importance to consider unidirectional flows when designing a super grid.

Voltage source converter based HVDC appears to be the best technical solution for the implementation of long distance transmission in such an offshore super grid. AC technology appears to be the most convenient choice for offshore nodes, but DC might also gain importance in this field, if reliable and affordable DC protection systems become available. A meshed DC grid offers significant advantages towards a solution with many independent point-to-point HVDC links, but also here protection is an unsolved issue that has to be overcome first.

Reliability assessment of HVDC-based super grids is still very difficult, because operational experience with new technologies like the modular multilevel converter is limited. This leads to a lack of data to calculate the failure probabilities.

A test system with a DC grid and the connected AC grids has been developed to serve as a common reference for a variety of DC grid studies.

Unlike classical AC grids, DC grids will be dominated by power electronics and the system behaviour will be determined to a large extent by the controllers of those power electronic systems. Large-scale implementation of power electronics with inappropriate control design has led to problems in AC systems before. Photovoltaic generation systems in Germany are a good example for this.

A simplified AC frequency model has been developed to assess how power electronic systems influence the grid frequency. This model has been used to

simulate how photovoltaic generation systems in Germany can endanger system stability. A 'grid-friendly' charging controller for plug-in electric vehicles with battery storage has been developed, and simulations have indicated that this control can contribute significantly to system stability.

Even though AC and DC grids have some significant differences, some of the general concepts and lessons regarding balancing are true for both, and tomorrow's DC grids can learn from today's AC challenges.

The balance in a DC grid should be defined as a current balance rather than an active power balance (as it is used in AC grids), and the voltage can serve as a balance indicator, similar to AC frequency in AC grids. The control base for controlling the voltage should also be current instead of active power, leading to linear system behaviour and a linear control task.

HVDC converter control methods can be regarded as cases of droop control with one or more linear segments in the characteristic control curve. Within one linear segment of the control curve, a HVDC converter can be represented by the Thevenin or Norton equivalent circuit.

To unify a variety of proposed control concepts, Undead-band droop control has been proposed as a general piece-wise linear voltage control, which includes all other proposed methods as special implementations of undead-band droop control. This concept could also be applied for other tasks than DC voltage control like AC frequency control.

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Schnappi	for the matpakke-service
Everyone else	who somehow for some reason was forgotten here

Contents

List of Equations

List of Tables

List of Figures

Nomenclature

,	decimal mark
I-V	Current-Voltage
P-f	Power-Frequency
P-V	Power-Voltage
C_{total}	total system Capacitance
I_i	Current of converter i
I_{error}	error Current (disturbing the current balance)
I_{total}	total system Current infeed
I_{nom}	nominal Current (base for pu)
I_{set}	Current setpoint
I_I	converter Current with current-based droop control
I_P	converter Current with power-based droop control
I_{equiv}	Current source of the Norton equivalent
k	droop Constant
k_I	current-based droop Constant
k_P	power-based droop Constant
$k_{I,\,\text{equiv}}$	equivalent current-based droop Constant for power-based droop control
$k_{P,\,\text{equiv}}$	equivalent power-based droop Constant for current-based droop control
k_1	droop Constant for normal operation

k_2	droop Constant for disturbed operation
P_{nom}	nominal Power (base for pu)
P_{set}	Power setpoint
P_P	converter Power with power-based droop control
P_I	converter Power with current-based droop control
R_{nom}	nominal Resistance (base for pu)
R_{equiv}	equivalent shunt Resistor, that would conduct I_{set} at V_{set}
T_{DC}	DC system Time Constant
V_{system}	average system Voltage
V_{nom}	nominal Voltage (base for pu)
V_{set}	Voltage setpoint
V_{equiv}	Voltage source of the Thevenin equivalent

Abbreviations

CIGRE	Conseil International des Grands Reseaux Electriques
CSC	Current Source Converter
DCS	Direct Current System
ESG	European Super Grid
HVDC	High Voltage Direct Current
MMC	Modular Multi-level Converter
NSSG	North Sea Super Grid
OGP	Oil&Gas Platform
PD	Proportional-Derivative
PI	Proportional-Integral
PID	Proportional-Integral-Derivative
PEV	Plug-in Electric Vehicle
ROWPP	Remote Offshore Wind Power Plant
VSC	Voltage Source Converter
V2G	Vehicle-to-Grid
WPP	Wind Power Plant

Chapter 1

Introduction

The North Sea is the world's first remote offshore region to see large-scale deployment of electric power infrastructure. The construction of the first projects has already started with a high pace, and many more projects are in the pipeline. Some future visions even go much further than today's activities.

Electric power infrastructure projects currently being pursued in the North Sea are grid connection cables for remote offshore wind power plants and oil&gas rigs. Also interconnection cables between onshore electric power grids being constructed at the moment and planned in the near future.

These offshore transmission projects are treated separately at the moment, but many foresee that these electric power assets will grow together in the future to form what is called the North Sea Super Grid (NSSG). Since no similar electric power infrastructure project has ever been done or attempted, the North Sea region plays a pioneering role in the world.

The major difference between the NSSG and the existing electric power grids is the fact that the grid is located offshore. This makes construction and maintenance challenging. The grid has to be based on electric power cables because of its offshore location. All existing large power systems are mainly based on overhead lines.

High Voltage Direct Current (HVDC) technology has been in focus for the NSSG. This is due to technical problems with AC subsea cable transmission over long distances. The Voltage Source Converter (VSC) has been in focus for AC-DC conversion, as it is well suited for the implementation of DC grids.

The NSSG will therefore likely be the first offshore cable-based HVDC power system. There are still several technical challenges relating to the construction of such a system, and some of these challenges have been addressed in this thesis.

1.1 Outline

Chapter 2 System design aspects of super grids are discussed, and the challenges for the development and operation have been identified. The focus is on the North Sea Super Grid, but also the European Super Grid is briefly treated. Asymmetric loading of lines in a (super) grid is defined, as it influences system design. An overview over the technical possibilities for the branches and the nodes of a super grid is given, and the advantages and disadvantages are discussed. Attention is given to offshore nodes, since they will be new constructions. Onshore nodes will be connection points to existing onshore grids, and not separate structures. Possible structures of super grids are treated. Reliability assessment of super grids is briefly discussed. A newly developed test system for super grid studies is described.

Chapter 3 Control aspects of the interactions between power electronic systems and AC power grids have been studied. The basic operational principles of AC grids are explained, and some information about grid frequency fluctuations is given. The basic mechanisms for frequency control in AC power systems are explained. The grid frequency stability challenges resulting from power electronic assets are discussed. The grid frequency model, which has been used in this chapter, is described briefly. The grid frequency stability threat, which is imposed mostly by photovoltaic systems in Germany, is treated. A new control method for power electronic grid assets, that includes frequency response, is described. Even though these AC control aspects are not directly related to the NSSG, they are relevant, as there are significant similarities between today's onshore AC systems and the future offshore DC systems in how power electronics influence the grid operation and stability.

Chapter 4 Balancing control for DC grids is discussed in detail. The basic operational principles of DC grids are explained, and the general definitions are introduced. Voltage control is argued to be the most suitable means to achieve balancing control, similar to frequency control in AC grids. The basic principles of voltage control in DC systems are explained, and the pros and contras of the different approaches are discussed. The existing voltage control methods for HVDC converter stations are explained in detail and classified systematically. Simplified linear models for HVDC converter stations are introduced, and the limitations of the validity of these models are explained. A new voltage control method is introduced which combines the advantages of the earlier mentioned methods. The possibilities to integrate converter stations of a HVDC grid into AC grid frequency control are discussed.

1.2 Contributions of the Thesis

Chapter 2

- Gathering and summarising all technical options for the construction of the NSSG. This assessment has been performed in a general and systematic way, not to exclude some technical possibilities. Technology dependent challenges have been identified.
- Investigating the potential of unidirectional HVDC systems. A method for identifying network branches with partly unidirectional loading has been developed. The feasibility of introducing unidirectional HVDC systems without reducing operational flexibility has been shown. Possible technical and economic advantages have been identified.
- Creating a comprehensive overview of the analytical power system reliability assessment techniques. The potential of these methods for predicting the reliability of future super grids has been evaluated.
- Leading the development of the CIGRE B4 DC Grid Test System. The development of a DC grid test system has been promoted within CIGRE B4. The development of the test system has been coordinated. A valuable test system has been created where the research community within and outside CIGRE B4 can benefit.

Chapter 3

- Raising awareness at an early stage for the significant threat to grid frequency stability, which is imposed by inappropriate grid connection guidelines. The possible consequences of the over-frequency disconnection of photovoltaic systems in Germany have been highlighted. Suitable counter-measures have been identified. Improvements for new grid connection guidelines have been proposed.
- Demonstrating the enormous potential of distributed power electronic grid assets to contribute to power system frequency stability at an early stage. A control strategy with integrated grid frequency support without the need for communication has been developed. Simulations have shown how plug-in electric vehicles can support grid frequency and avoid load shedding.

Chapter 4

- Redefining the balance in DC grids from active power balance to DC current balance. Linear balance equations have been achieved through this definition. The advantages of that linear definition have been highlighted.
- Evaluating the advantages of DC current (instead of active power) as a control base for DC voltage control. A linear control approach to address the linear balance task has been proposed.
- Classifying the existing methods for DC voltage control in HVDC grids. Conceptual similarities have been identified. The pros and contras have been discussed.
- Assessing the possibilities of linear modelling for HVDC converter stations. Thevenin and Norton equivalent circuits have been proposed for modelling converter stations with linear control. The limitations of these models have been identified.
- Developing a new generalised control method for voltage control in HVDC grids. This method combines the advantages of the existing methods. It can also serve as a generalised control framework as the other methods can be seen as specific implementations of it.
- Assessing possibilities for automatic exchange of primary frequency control reserves through HVDC connections without real-time communication. DC voltage has been proposed as a means of communication. A control strategy for artificial coupling of AC frequency and DC voltage has been developed.

1.3 List of Publications

This thesis is based on 15 publications. These 15 publication are sorted in three groups, which are treated in the three main chapters of this thesis (Chapters 2, 3 and 4). The nine most relevant publications are included in the appendix as full articles.

1.3.1 Publications regarding Chapter 2

I The North Sea Super Grid - A Technical Perspective

II Technical Aspects of the North Sea Super Grid

III Benefits of Asymmetric HVDC Links for Large Scale Offshore Wind Integration

IV A European Supergrid: Present State and Future Challenges

V Overview of Analytical Power System Reliability Assessment Techniques

VI The CIGRE B4 DC Grid Test System

I The North Sea Super Grid - A Technical Perspective

Authors	Til Kristian Vrana Raymundo E. Torres-Olguin Bing Liu Temesgen M. Haileselassie
Year	2010
Status	Published and presented
Publication	ACDC Power Transmission Conference proceedings
Publisher	IET
Location	London
Appendix	Article not included

The North Sea Super Grid will likely include several independently planned projects, comprising a variety of different AC and DC technologies. The offshore clusters will probably be AC-based. Long distance transmission will be HVDC and nowadays voltage source converter technology is applied for offshore projects. However in the future, current source converter technology could become an interesting option. Hybrid HVDC systems that combine voltage source converter and current source converter technology, multi-terminal HVDC systems and parallel HVDC links could gain importance for the development of the North Sea Super Grid.

In this article, an overview over possible technologies is given and it is discussed how these can be utilised to realise the North Sea Super Grid.

This article has not been included in the appendix, because it lost part of its significance when Publication II was written, which can be seen as a more mature and advanced view on the same topic.

II Technical Aspects of the North Sea Super Grid

Authors	Til Kristian Vrana Olav B. Fosso
Year	2011
Status	Published and printed
Publication	Electra Magazine
Publisher	CIGRE
Location	Paris
Appendix	Full article included

The future electric grid development plan in Europe foresees the North Sea Super Grid (NSSG). This grid will need to integrate individually and independently planned projects, leading to a grown rather than optimised structure. This will offer a lot of technical challenges, since it is a clear pioneering project.

Offshore cluster grids could be either realised in AC or DC, and significant advantages and drawbacks come along with both options. Power balancing in offshore cluster grids is challenging due to the characteristics of modern wind turbines, which will play an important role. These clusters can be connected to each other and to shore via HVDC links.

Radial connected HVDC will gain importance with increasing number of offshore clusters. Parallel HVDC connections can offer the needed capacities and the important redundancy. A meshed HVDC grid structure can offer both, but additional challenges come along with it.

In this article, which can be seen as a more mature and advanced version of Publication I, an overview over the relevant technologies is given and the challenges of realising the NSSG are discussed.

III Benefits of Asymmetric HVDC Links for Large Scale Offshore Wind Integration

Authors	Til Kristian Vrana Daniel Huertas-Hernando Olav B. Fosso
Year	2012
Status	Published and presented
Publication	PES General Meeting proceedings
Publisher	IEEE
Location	San Diego
Appendix	Full article included

The large remote offshore wind clusters that are planned in the North Sea will most likely be connected with a meshed HVDC grid. Power will mostly flow from the offshore wind clusters to shore, creating asymmetrical requirements for the HVDC links that will consist of several parallel HVDC systems.

To address these asymmetrical requirements, some of the HVDC systems could be designed unidirectional, resulting in possible changes and simplifications (especially to the protection system).

Assessment of a future scenario has shown that 42 % of the HVDC systems can only be operated unidirectionally. The remaining systems could in theory be used in both directions, but power flow optimisation has shown that this will not happen in many cases.

A first cost calculation has indicated that almost 6 % of the investment cost could be saved when unidirectional systems are implemented. This indicates the need to consider the asymmetric requirements and to develop unidirectional HVDC systems.

IV A European Supergrid: Present State and Future Challenges

Authors	Stijn Cole Til Kristian Vrana Jean-Baptiste Curis Chen-Ching Liu Karim Karoui Olav B. Fosso Anne-Marie Denis
Year	2011
Status	Published and presented by Stijn Cole
Publication	PSCC Conference proceedings
Publisher	PSCC
Location	Stockholm
Appendix	Full article included

Europe has a clear objective of obtaining a large share of wind power in the overall energy mix. A significant part of the installed wind power capacity will come from offshore wind power plants.

As an alternative to connecting every wind power plant to the onshore grid separately, the 'super grid' concept has been proposed. A super grid would allow international trade and balancing, and can accommodate renewable energy sources, such as concentrated solar power and offshore wind energy.

In this article, an overview of technical challenges associated to meshed multi-terminal direct current super grids is given, and alternatives and a roadmap that could expedite the development of a European Super Grid are presented.

The author of this thesis has been invited to contribute to this survey article with a section on alternative structures for the offshore parts of super grids.

V Overview of Analytical Power System Reliability Assessment Techniques

Authors	Til Kristian Vrana Emil Johansson
Year	2011
Status	Published and presented
Publication	CIGRE Symposion proceedings
Publisher	CIGRE
Location	Recife
Appendix	Article not included

Reliable electric power supply is essential for modern society. The extensive use of electricity has led to a high susceptibility to power failures. In this way, reliability of supply has gained focus and it is considered increasingly important for electric power system planning and operation.

In this article, an overview is given of the state of the art of analytical power system reliability assessment techniques. The article is addressed to readers with an interest in the possibilities and limitations of these models.

The motivation behind this article is to establish a comprehensive overview of the field of analytical power system reliability assessment techniques and to serve as input for further research and development in the area of applicability.

This article has not been included in the appendix, because the described reliability assessment techniques have not been applied in this thesis.

VI The CIGRE B4 DC Grid Test System

Authors	Til Kristian Vrana Sebastien Dennetiere Yongtao Yang Jose Jardini Dragan Jovcic Hani Saad
Year	2013
Status	Published and printed
Publication	Electra Magazine
Publisher	CIGRE
Location	Paris
Appendix	Full article included

Several CIGRE B4 working groups and many other researchers focus on the new research field of DC grids. The CIGRE B4 DC Grid Test System has been designed by working groups B4-58 and B4-57, in order to organise discussions among the different groups.

The test system is of a very general nature with AC and DC parts. Its purpose is to have a common reference for studies concerning DC grids, within but also outside CIGRE B4. All of the CIGRE B4 working groups that focus on DC grids will use this system (the entire system or parts of it), as much as possible. If the engineering community would also start to use this system, as it has been done with the CIGRE line commutated converter HVDC benchmark, results of various DC grid studies could be compared on the same basis.

This article contains a description of the CIGRE B4 DC Grid Test System. The initial results of power flow are presented which confirm steady state operation and small signal stability. A preliminary version of the system has been used in Publication XIII and Publication XIV.

1.3.2 Publications regarding Chapter 3

VII Improved Requirements for the Connection to the Low Voltage Grid

VIII The 50,2-Hz-Problem in the Context of Improved Requirements for Grid Connection

IX A novel control method for dispersed converters providing dynamic frequency response

X Smart Standards for Smart Grid Devices

VII Improved Requirements for the Connection to the Low Voltage Grid

Authors	Gunnar Kaestle Til Kristian Vrana
Year	2011
Status	Published and presented by Gunnar Kaestle
Publication	CIRED Conference proceedings
Publisher	CIRED
Location	Frankfurt
Appendix	Full article included

In Germany, about 80 % of installed photovoltaic power was connected to the low voltage grid in 2011. During the summer of 2011, more than 12 000 MW of actual infeed has been observed on a regular basis.

This indicates that low voltage power producers have gained significant system relevance, and as a consequence they need to contribute to grid stabilisation. Former guidelines often demanded an immediate disconnection in case of disturbances, but this is counter-productive and the issue is taken care of by new requirements for grid connection.

In this article, the risk of a major disturbance in case of an over-frequency event is explained. The results of a simulation with a simplified European grid frequency model are presented.

Measures for the incident and risk management as well as anticipatory precautions are proposed. Finally, a comparison between past deficits in the standardisation of medium voltage (wind) and low voltage (photovoltaic) appliances is presented to raise the awareness about the dynamic behaviour of electric consumers (plug-in electric vehicles).

This article can be seen as a preliminary version of Publication VIII.

VIII The 50,2-Hz-Problem in the Context of Improved Requirements for Grid Connection

Authors	Gunnar Kaestle Til Kristian Vrana
Year	2011
Status	Published and presented together with Gunnar Kaestle
Publication	VDE - ETG Conference proceedings
Publisher	VDE Verlag
Location	Wuerzburg
Appendix	Article not included

In Germany, about 80 % of installed photovoltaic power was connected to the low voltage grid in 2011. During the summer of 2011, more than 12 000 MW of actual infeed has been observed on a regular basis.

This indicates that low voltage power producers have gained significant system relevance, and as a consequence they need to contribute to grid stabilisation. Former guidelines often demanded an immediate disconnection in case of disturbances, but this is counter-productive and the issue is taken care of by new requirements for grid connection.

In this article, the risk of a major disturbance in case of an over-frequency event is explained. Results of a simulation with a simplified European grid frequency model are presented.

The European grid frequency model (from Publication VII), has been adapted to represent two grid regions instead of one. It is therefore able to calculate power flows between the regions and captures oscillations caused by an abrupt power imbalance in one region.

This article, which can be seen as a more mature and advanced version of Publication VII, has not been included in the appendix, because it is written in German.

IX A novel control method for dispersed converters providing dynamic frequency response

Authors	Til Kristian Vrana Christian Hille
Year	2011
Status	Published
Publication	Electrical Engineering Journal
Publisher	Springer Verlag
Location	Berlin
Appendix	Full article included

Power electronic converters are flexible and able to react very fast in relation to the time constants associated with the AC grid frequency. Many power converters, such as battery charging devices, use only a small part of their technical capabilities to fulfill their primary task.

In this article a new control method is developed, which combines the primary converter function with grid frequency support. No communication between the network operator and the converter is necessary for the basic grid supporting functions. Dispersed frequency support as suggested by the developed control method could be adopted as a requirement to future grid codes.

The frequency stability can be influenced positively, using the power converters control potential, without penetrating its primary functions under normal power system conditions. In case of severe frequency deviations, priority is given to this grid support functionality, which can significantly improve the security of supply.

Plug-in electric vehicles with battery storage are used as an example, and the impact on the continental European grid frequency can be observed by simulations. Even a small percentage of electric cars can significantly influence the grid frequency.

X Smart Standards for Smart Grid Devices

Authors	Gunnar Kaestle Til Kristian Vrana
Year	2011
Status	Published and presented by Gunnar Kaestle
Publication	OTTI Conference proceedings
Publisher	OTTI
Location	Munich
Appendix	Article not included

On the generation side, grid codes for distributed energy resources had to be improved when medium voltage (wind) and later low voltage (photovoltaic) feedings became system relevant. This enables 'grid-friendly' behaviour of distributed generation units to be achieved.

On the load side, the self-regulation effect of loads is continuously shrinking, due to the non frequency dependent control of most loads with a power electronic interface. However, plug-in electric vehicles have the potential to act as a large collective distributed power source which is able to filter a substantial part of short-term power fluctuations.

The intention of the authors is to sensitise interested readers to work on standards concerning the dynamic interaction between the grid and battery charging devices at an early stage of the deployment of this technology. The primary targets are to avoid negative effects on grid stability and to deliver positive auxiliary services with grid-friendly consumption.

In this article, the authors explain the need for smart requirements not only for distributed generation, but also for distributed dispatchable loads.

This article has not been included in the appendix, because its focus is outside the scope of this thesis.

1.3.3 Publications regarding Chapter 4

XI A Classification of DC Node Voltage Control Methods for HVDC Grids

XII Active Power Control with Undead-Band Voltage & Frequency Droop for HVDC Converters in Large Meshed DC Grids

XIII Active Power Control with Undead-Band Voltage & Frequency Droop Applied to a Meshed DC Grid Test System

XIV Dynamic Active Power Control with Improved Undead-Band Droop for HVDC Grids

XV Main Grid Frequency Support Strategy for VSC-HVDC Connected Wind Farms with Variable Speed Wind Turbines

XI A Classification of DC Node Voltage Control Methods for HVDC Grids

Authors	Til Kristian Vrana Jef Beerten Ronnie Belmans Olav B. Fosso
Year	2013
Status	Published
Publication	Electric Power System Research Journal
Publisher	Elsevier
Location	Amsterdam
Appendix	Full article included

In a DC grid, contingencies such as converter outages give rise to an imbalance that is reflected in the DC node voltages in the grid. This imbalance has to be accounted for by changing the currents flowing in and out of the DC system. These DC node voltages can be directly influenced by controlling the DC current of the HVDC converter at that node. Different control strategies can be applied to balance the currents in a DC grid after a contingency.

In this article, the different control strategies that can be applied in DC grids are systematically introduced, thereby aiming to provide a framework for classifying the different control strategies available in the literature.

It is discussed how all control strategies can theoretically be regarded as limiting cases of a voltage droop control and how the different control concepts can be combined, leading to more advanced control schemes such as voltage margin control or dead-band droop control.

The work done for CIGRE working group B4-58 for the chapter 'DC node voltage control' of the future technical brochure is summarised in this article.

XII Active Power Control with Undead-Band Voltage & Frequency Droop for HVDC Converters in Large Meshed DC Grids

Authors	Til Kristian Vrana Lorenzo Zeni Olav B. Fosso
Year	2012
Status	Published and presented
Publication	EWEA Conference (EWEC) proceedings
Publisher	EWEA
Location	Copenhagen
Appendix	Full article included

A new control method for large meshed HVDC grids has been developed. It uses a piecewise linear droop curve, with different droop values for the different segments. The proposed method is based on a so-called 'undead'-band, meaning that control activity is reduced within the band, but not set to zero as with a regular dead-band.

The control method can help to keep the active power balance at the AC and DC sides. The method definition is kept wide, leaving the possibility for control parameter optimisation. Other known control methods can be seen as specific examples of the proposed method. It can serve as a framework for the control of large DC grids, defining a common standard for the control scheme, but still leaving a lot of freedom for individual adjustments.

It operates with a minimum of required communication. New converters can be added to the system without changing the control of the other individual converters. It is well suited to achieve high reliability standards due to the distributed control approach.

The control method has been tested on a three-terminal DC grid. In Publication XIII it has also been tested on a larger system. In Publication XIV the control method is improved for better dynamic performance.

XIII Active Power Control with Undead-Band Voltage & Frequency Droop Applied to a Meshed DC Grid Test System

Authors	Til Kristian Vrana Lorenzo Zeni Olav B. Fosso
Year	2012
Status	Published and presented
Publication	Energycon Conference proceedings
Publisher	IEEE
Location	Firenze
Appendix	Article not included

The undead-band droop control strategy has been proposed in Publication XII. The control strategy combines DC voltage and AC frequency droop. It provides sufficient room for optimisation for both normal and disturbed operation. Its main features are flexibility, reliability due to distributed control, easy expandability of the system and minimisation of communication needs.

The control strategy has been tested on a simple three-terminal grid in Publication XII. The simplicity of the test system has been criticised, raising doubts about the applicability of the control strategy for larger systems.

The control strategy has therefore been tested on an early version of the meshed CIGRE B4 DC Grid Test System from Publication VI. Its effectiveness has been verified, to demonstrate its suitability for application in future meshed HVDC grids. In Publication XIV the control method is improved for better dynamic performance.

This article has not been included in the appendix, because it does not contain additional information about the control method, and because the utilised version of the CIGRE B4 DC Grid Test System is outdated.

XIV Dynamic Active Power Control with Improved Undead-Band Droop for HVDC Grids

Authors	Til Kristian Vrana Lorenzo Zeni Olav B. Fosso
Year	2012
Status	Published and presented
Publication	ACDC Power Transmission Conference proceedings
Publisher	IET
Location	Birmingham
Appendix	Full article included

The undead-band droop control strategy has been proposed in Publication XII and tested on a meshed system in Publication XIII. This control method uses a piecewise linear droop curve with different droop values for the different segments. It was defined for steady state operation.

In this article, the control method has been optimised for dynamic performance.

Non-linearities at the junctions of two linear droop sections have been addressed. Also the non-linearity of power-based DC voltage control has been addressed. Dynamic instability due to high control gains has been treated and a new improved control structure has been proposed.

The concepts have been validated with RMS simulation with the DIgSILENT PowerFactory software on an early version of the meshed CIGRE B4 DC Grid Test System from Publication VI.

XV Main Grid Frequency Support Strategy for VSC-HVDC Connected Wind Farms with Variable Speed Wind Turbines

Authors	Temesgen M. Haileselassie Raymundo E. Torres-Olguin Til Kristian Vrana Kjetil Uhlen Tore M. Undeland
Year	2011
Status	Published and presented
Publication	PowerTech Conference proceedings
Publisher	IEEE
Location	Trondheim
Appendix	Article not included

The AC frequency of a HVDC connected remote offshore wind power plant is determined by the control of the offshore HVDC converter, independently of the onshore grid frequency. The independence of the offshore AC frequency makes it difficult for the wind turbines to contribute to frequency support of the onshore grid.

In this article, an artificial coupling of the offshore grid and the onshore grid frequencies is developed, for onshore grid frequency support by offshore wind power plants. Artificial frequency coupling is achieved by use of droop controllers for the DC voltage control. The DC voltage on the HVDC link is used as a means of communication for the integration of the wind power plant into onshore AC frequency control.

A case study, using PSCAD, demonstrates the effectiveness of artificial frequency coupling for onshore grid frequency support.

This article has not been included in the appendix, because its focus is outside the scope of this thesis.

Chapter 2

Super Grids

The basic definition of a super grid can be derived directly from the word's etymology:

A super grid is a grid which resides 'on top' of the existing grid. This basic definition is important in that it immediately makes clear that the super grid is not just an extension of the existing grid, but a whole new layer or backbone, or at the very least a new independent structure, connected to the existing grid.

A super grid is also a grid which is 'better' or more advanced than the existing grid, typically associated with being large with high power ratings and long transmission distances.

The 'Smart Grid' is a term frequently used in electric power system research. It often refers to the modernisation of existing 'non-smart' electric power distribution infrastructure. New transmission infrastructure constructions like super grids will of course also be 'smart', but the term is usually not applied in this context.

The utilisation of renewable energy sources leads to electric power production at remote locations far away from the load centres. The volatile nature of some renewable energy sources (especially wind power and photovoltaic) creates power fluctuations resulting in additional electric power flows. The European electricity market integration also leads to increased long distance power flows.

These developments are therefore creating the need for massive reinforcements of the electric power transmission grids. Super grids are seen by many as the future solution for large-scale long distance electric power transmission. Various system design aspects of super grids are addressed in this chapter.

This chapter is organised in nine sections:

Section 2.1	The North Sea Super Grid (NSSG) project is treated.
Section 2.2	The European Super Grid (ESG) project is introduced and briefly treated.
Section 2.3	Asymmetric loading of lines in a (super) grid is defined, as it influences system design.
Section 2.4	An overview over the technical possibilities for the branches of a super grid is given, and the advantages and disadvantages are discussed.
Section 2.5	An overview over the technical possibilities for the nodes of a super grid is given. Attention is given to offshore nodes, since they will be new constructions. Onshore nodes will be connection points to existing onshore grids, and not separate structures.
Section 2.6	Possible structures of super grids are treated.
Section 2.7	Reliability assessment of super grids is briefly discussed.
Section 2.8	A newly developed test system for super grid studies is described.
Section 2.9	The summary of this chapter.

This chapter is based on Publications I - VI.

2.1 The North Sea Super Grid

The North Sea Super Grid (NSSG) will probably be the first offshore electric power grid [Troetscher et al., 2009]. The countries around the North Sea have agreed to create the NSSG under the North Seas Countries Offshore Grid Initiative [Council of the European Union, 2009].

The basic definition of a super grid says that a super grid resides ‘on top’ of the existing grid. As there is no existing grid in the North Sea, the name is not really correct. However, in the broader picture, also considering the future onshore extensions of the NSSG, it can be seen as a super grid structure on top of the existing onshore grids around the North Sea. This view becomes even clearer when considering the European Super Grid (ESG), treated in Section 2.2.

The construction of the NSSG will be a clear pioneering project and will pose a lot of technical challenges. This grid will be built by several countries, involving many different transmission system operators and companies, combining projects with different goals and time horizons. It will be serving many installations and with several connections to different onshore grids.

In view of the numerous offshore projects already existing, 'green field' approaches (system design assuming no existing infrastructure) to the conception of NSSG seem questionable. The construction of the NSSG may already have begun with 'Bard offshore 1' the world's first Remote Offshore Wind Power Plant (ROWPP).

Existing onshore AC grids have all been built in a modular way, and this method of progress is usual for electric power systems. Offshore point-to-point electric power infrastructure projects on the other hand have until now always been planned, designed and constructed as concrete well-defined projects. Since it would be unrealistic to plan and build a huge system like the NSSG in one step, it is more likely that the development will follow the organic growing process known from power system development. This approach is however entirely new to offshore electric power infrastructure projects.

The number and the large power rating of the needed links imply the consideration of an advantageous meshed grid structure. Several studies like [v. Hulle et al., 2009] [ENTSO-E, 2011] [Veum et al., 2011] [d. Decker et al., 2011] have indicated, that a meshed grid offers economic benefits compared to a solution consisting only of point-to-point connections. To justify the tremendous investments, reliability, redundancy, robustness and flexibility will be of major importance. To ensure the required properties of the NSSG, appropriate control is important, and it receives special attention in this thesis.

The NSSG is generally described in Publication I and Publication II. The offshore power grid in the North Sea will have different requirements than many other power grids, since there will be a lot of ROWPPs but almost no loads. The connection points to the onshore AC grids represent the electric loads of the NSSG. This results in the power flow having a predominant direction, from offshore to shore. If this fact is taken into account properly, significant design improvements can be achieved, as described in Publication III.

2.1.1 Drivers

There are several drivers for the NSSG and the most important are listed here.

2.1.1.1 Remote Offshore Wind Power Plants

The ambitious plans of the EU to implement large-scale offshore wind power in the North Sea region create the demand for offshore electric power infrastructure. The next decades will see large-scale deployment of wind power plants (WPP) in the North Sea.

Offshore WPPs that are located near shore can directly be integrated into the power system, somehow similar to onshore WPPs. More challenging (from an electrical engineering point of view) are the Remote Offshore Wind Power Plants (ROWPP) located far away from shore. One ROWPP (distance to shore 90 km) is already in operation (Bard offshore 1).

Once an offshore grid is in operation, its presence will also improve the possibility of adding smaller ROWPPs later, which would not have been economical if they needed a long separate connection to shore.

2.1.1.2 Offshore Oil&Gas Platforms

The rising prices of fossil fuels lead to exploitation of more and more remote subsea reservoirs. The North Sea has many reservoirs which are exploited at the moment and even more that can be exploited in the future. Stricter environmental regulation of the oil&gas industry demands different power supply solutions for Oil&Gas Platforms (OGP), avoiding local low-efficiency gas turbines. There are three possible options:

- Power supply of offshore OGPs can be done via electric power cables from shore. This 'grid connection' is often called 'electrification', even though also platforms with local gas turbines are electrical. Grid connection is challenging for remote offshore OGPs, but two systems are already in operation (Troll OGP and Valhall OGP). This approach is costly and at the moment only realistic for large fields with high power consumption.

- Power supply could partly be done from nearby ROWPPs (when the wind is blowing). The electrical integration of offshore loads and generation is advantageous, since it avoids long transmission cables and therefore also transmission losses. This approach could significantly reduce the fuel consumption of the OGP and therefore also reduce carbon emissions.

- A combination of both mentioned approaches offers the best advantages. Power supply would partly come from nearby ROWPPs and partly from shore.

2.1.1.3 The Pan-European Electricity Market

The liberalisation and coupling of electricity markets in Europe demand stronger interconnections between the power systems of the UK, continental Europe and Scandinavia. Increased transmission capacity will give more dispatch flexibility and, if done correctly, lead to an overall cheaper and more environmentally friendly electricity supply.

2.1.1.4 Balancing of Renewable Energy

The impact of power output fluctuations of non-dispatchable power sources is increasing massively, as several European countries are constructing WPPs on a large scale. Since wind fluctuations mostly are a regional phenomenon, this development can and will lead to large regional power imbalances. The NSSG could help to balance these wind fluctuations, because the cross correlation of wind speeds all over the North Sea area is much lower than within a region or a country; or in simple words: 'The wind is always blowing somewhere'.

Furthermore, the tremendous value of the storage capacity and flexibility of Norwegian hydropower can only be utilised if the interconnections between Norway and the rest of Europe are sufficient.

2.1.2 Structure

The infrastructure in the NSSG can be divided into four levels (shown in Figure 2.1):

I Generation and loads [low / medium voltage]

II Offshore collection grids [medium voltage]

III Offshore cluster grids [medium / high voltage]

IV Long distance offshore transmission [high voltage]

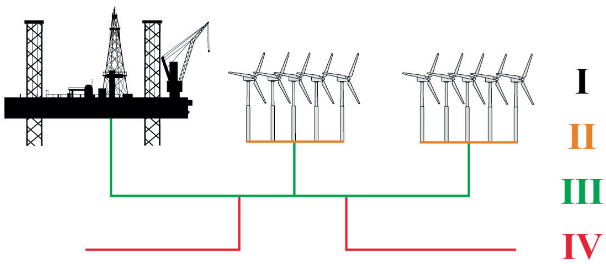

Figure 2.1: Infrastructure levels of the NSSG

2.1.2.1 Offshore Generation and Loads

The largest amount of units that will be connected to the NSSG will be wind turbines, while other generation types (wave power plants, gas turbines on

OGPs) will play a minor role. Offshore loads (pumps and compressors at OGPs, WPP internal loads) will not play a major role. The main share of the produced electric power will not be consumed offshore, but transferred to shore. The onshore connection points will therefore act as the load to the offshore grid.

2.1.2.2 Offshore Collection Grids

Offshore collection grids are within a WPP or an OGP.

The WPP collection grid connects all the wind turbines of a WPP to the point of common coupling, which can be a transformer or converter station. An OGP collection grid is, in a similar way, connecting all the electrical devices on such a platform to the point of common coupling. A typical radial WPP collection grid layout is shown in Figure 2.2.

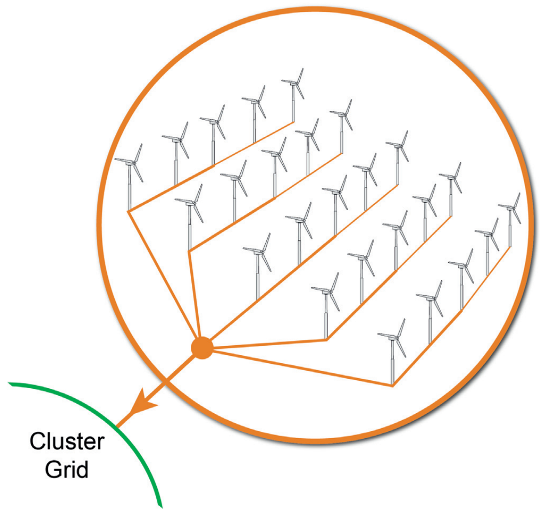

Figure 2.2: Wind power plant collection grid

A WPP with all turbines and the collection grid is planned and constructed in a single process, enabling good coordination of the activities. The system is usually not changed significantly afterwards. The entire system can be supervised and controlled by a central control unit. The same applies to OGP internal grids.

Even though challenges have been experienced with some of the first offshore WPP collection grids, these challenges can be addressed in a direct way due to the limited size of such grid.

2.1.2.3 Offshore Cluster Grids

An offshore cluster grid connects several WPPs together, and also integrates offshore loads (a possible layout shown in Figure 2.3).

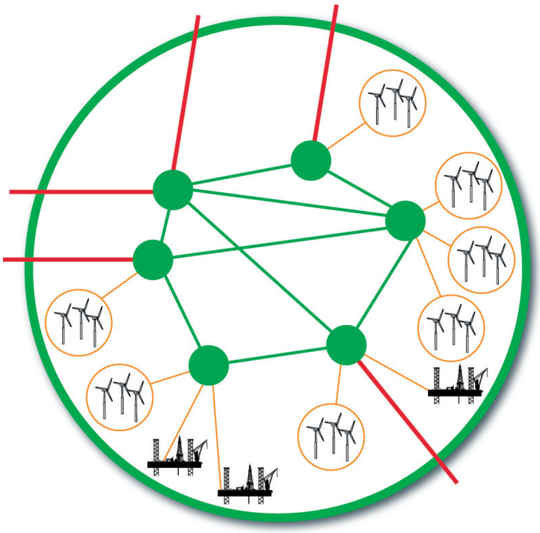

Figure 2.3: Offshore cluster grid

The future offshore clusters will be much larger than a single WPP. This makes availability important indicating the need for a meshed structure. The planning and operation of an offshore cluster grid can be challenging, since it will incorporate several WPPs from different operators and manufacturers, which might use different types of collection grids.

2.1.2.4 Long Distance Transmission

Long distance offshore transmission is challenging and the only realistic solution is with subsea HVDC cables. This issue is treated in detail in Section 2.4.

2.1.3 Layout

The countries around the North Sea basically agree that an NSSG will be needed in the future and that it has to be developed. This is a good base for a coordinated approach, which is needed to make such a huge project possible.

There are three regions in the North Sea, which will play a major role in the deployment of the NSSG:

- The German Bight is an offshore area where many ROWPPs are planned. The construction has already started and the world's first HVDC connected WPP is already in operation (Bard Offshore 1). Since the distance between those ROWPP will be smaller than the distance to shore, intelligent grid solutions will offer benefits compared to radial connectors.
- The Valhall OGP in Norway is connected to shore via HVDC [ABB]. This HVDC link is another step towards the NSSG, but due to the small power rating (78 MW) will it be of minor importance. However, the integration of Norway into the NSSG is of special importance, due to the Norwegian onshore hydropower stations.
- The Doggerbank is supposed to become the largest wind cluster in the UK [Forewind], but this project is still in the planning process. In total 9 000 MW of WPPs are to be constructed, indicating that it will become an important node in the NSSG.

Considering these three regions, the general structure of the NSSG can more or less be determined, and a simplified topology is shown in Figure 2.4.

A variety of detailed topologies for the NSSG have been studied, optimised, proposed and evaluated in several studies [d. Decker et al., 2009]. These studies can be taken as a guideline, but many of them are to some extent unrealistic since they are based on a 'green field' approach. The construction of electric power infrastructure in the North Sea has already started, undermining the validity of the 'green field' based concepts.

2.1.4 Future Development

The deployment of a full scale NSSG for the grid connection of the first pioneering offshore projects cannot be justified, nor financed. Individual projects are therefore coordinated one by one at the moment, and they do not follow an internationally agreed master plan. The ROWPP project at Kriegers Flak has shown how difficult it can be to plan a large infrastructure investment where several countries are involved [50 Hertz Offshore GmbH, 2010]. The future NSSG will be by far larger than the offshore wind cluster at Kriegers Flak, and so might the coordination problems be.

This individual approach regarding technical standards and voltage level is logical, but will lead to complication in the future, when these systems are to be interconnected. Since a variety of technologies will have to be operated together, standardised interfaces will be crucial.

Technical development of VSC-based offshore HVDC technology is advancing very quickly, and the fast pace has advantages and drawbacks. On the one hand, the newly developed technologies are an important enabler for

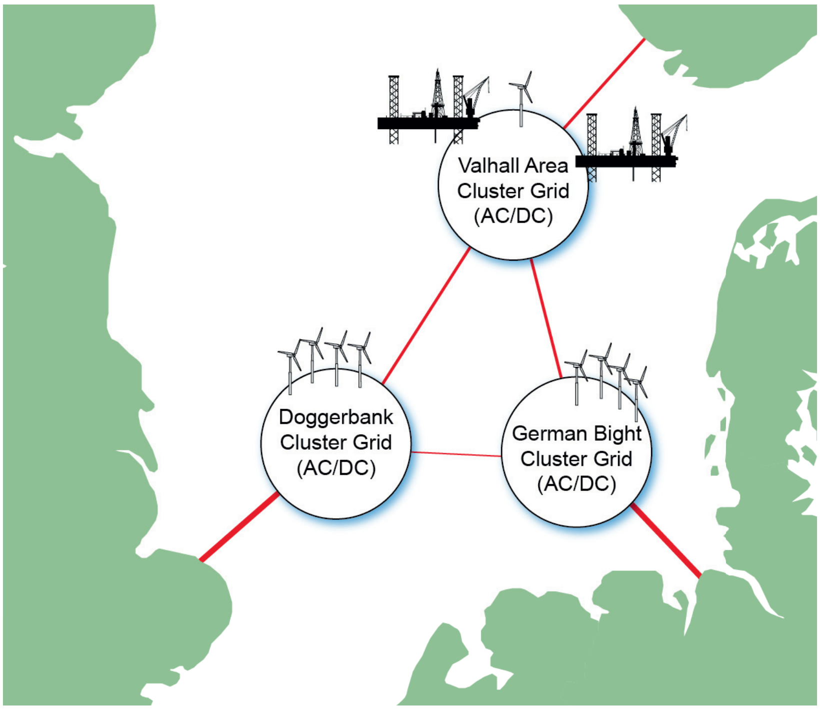

Figure 2.4: Simplified NSSG topology

the NSSG. On the other hand, the fast changes counteract the highly needed standardisation efforts. Additional challenges arise when the information needs of the operators conflict with the secrecy of technical details of the component suppliers.

By the time the NSSG project will be realised, many offshore facilities will already exist. The NSSG must integrate these facilities and cannot start from a green field. There is a need to integrate individually and independently planned projects, comprising several DC and AC voltage levels and possibly even different AC frequencies.

The NSSG will not be built in one step as a planned system. This flexible and modular approach is different from all existing HVDC projects. It has significant similarity with the evolution of the onshore electric power systems and will lead to a grown rather than an optimised structure. Flexibility will also be needed if the NSSG is to be integrated in a future European Super Grid.

2.1.5 A Future NSSG Scenario

The WindSpeed project, assesses the potential for further development of offshore WPPs in the Central and Southern North Sea [Veum et al., 2011]. The overall objective of the project is to develop a 2020-2030 roadmap for the deployment of offshore WPPs in this region of the North Sea bounded by Belgium, Denmark, Germany, the Netherlands, Norway and the United Kingdom.

The 'Grand Design' scenario from the WindSpeed project has been chosen for this thesis.

2.1.5.1 The 'Grand Design' Scenario

The 'Grand Design' scenario is the most pro-offshore wind scenario considered in the WindSpeed project. Figure 2.5 shows the eight remote offshore wind clusters, which are considered for the NSSG. A maximum possible potential ($\sim$ 88 000 MW) for the installed capacity at the remote offshore clusters is assumed. All near shore WPPs do not appear, since they can be directly integrated into the onshore power systems, somehow similar to onshore WPPs.

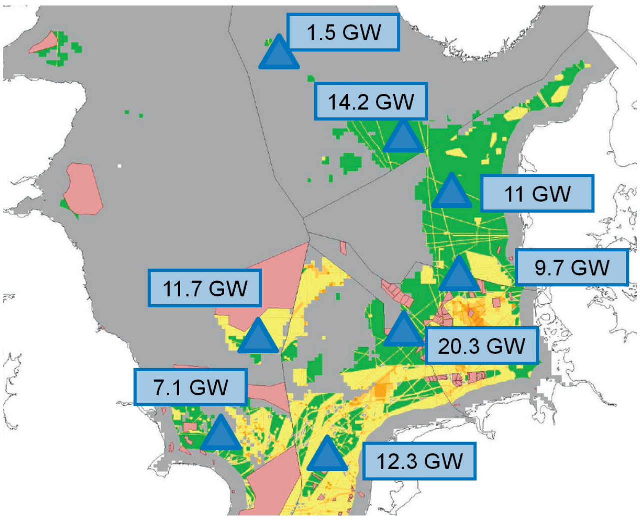

Figure 2.5: Future North Sea wind clusters

In this scenario it is assumed that high level transnational coordination for the development of an offshore grid is possible.

2.1.5.2 The Optimised NSSG Structure

An optimisation algorithm was used to identify the optimal offshore transmission infrastructure for the scenario. The details about the optimisation are not relevant in this thesis, and they can be found in [Veum et al., 2011]. The outcome is relevant for this thesis and is shown in Figure 2.6. Of the eight offshore nodes, only five are connected to a meshed offshore grid structure. Two are connected in a small structure between continental Europe and the UK. One is connected in the middle of a point to point connection between Scandinavia and the UK.

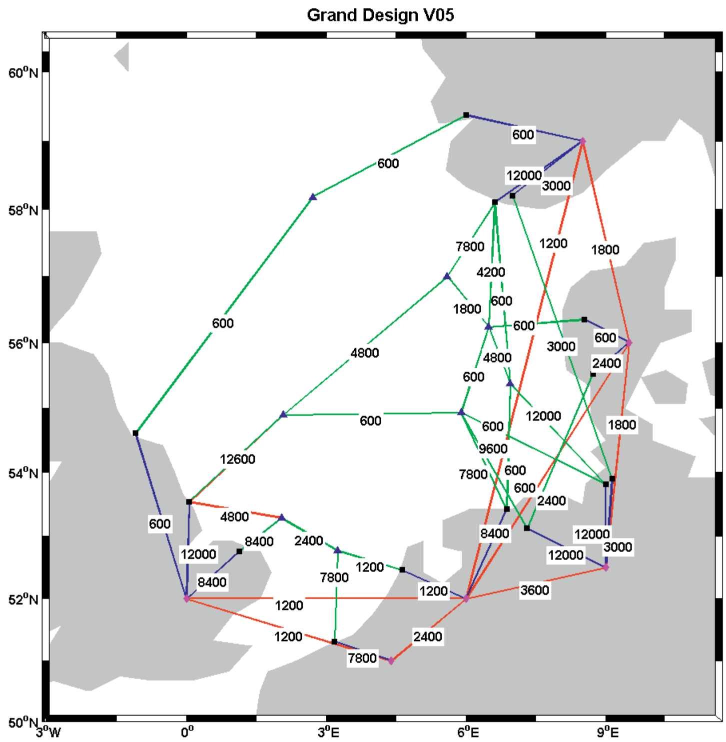

Figure 2.6: Optimised grid structure

From this complete grid topology the meshed part is extracted and shown in Figure 2.7. The outcome looks quite similar to Figure 2.4. All lines of the meshed grid together contain a total of 69 000 MW of transmission capacity.

Most of the transmission capacity of the meshed offshore grid is concentrated in the four strongest links of the system (indicated by thick lines in Figure 2.7).

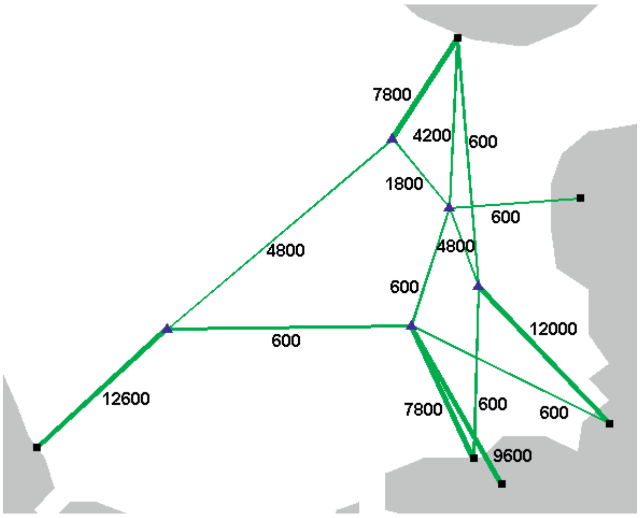

Figure 2.7: Meshed offshore grid

These four links are, as expected, the direct connections of the offshore wind clusters to the closest shore.

The two links from the German Bight node to Germany and the Netherlands are treated here as one link, since their connection points onshore are nearby.

2.1.5.3 Branches with Inherent Asymmetric Loading

The NSSG is a good example where branches with inherent asymmetric loading will appear. The offshore wind clusters will have a huge power surplus due to the large number of ROWPPs and the small amount of offshore loads. This surplus leads to a preferred power flow direction, from offshore cluster to shore. Details about the identification of branches with inherent asymmetric loading can be found in Section 2.3.

This property of the NSSG is not related to specific layouts, future scenarios or technological solutions. It is purely based on the fact that the offshore cluster will have a large power surplus.

The four strongest links (indicated by thick lines in Figure 2.7) all fulfill the developed criteria (Section 2.3) for inherent asymmetric loading. They can only be fully loaded towards shore. It directly appears natural, that a scenario where the offshore wind cluster imports large amounts of power from the shore is impossible, since that power cannot be consumed anywhere.

To design a transmission line especially for asymmetric loading, it is important to calculate the amount of unidirectional capacity within the link. Those four mentioned links contain a total unidirectional transfer capacity of 29 000 MW, which is 58 % the capacity of those links. Compared to all links of the meshed offshore grid, it is 42 % of the total transmission capacity.

The details can be found in Publication III. There is also an estimation about the possible investment cost savings, resulting from the consideration of asymmetry. It is also shown, based on computer simulations, that even less bidirectional capacity is needed under any realistic operation conditions.

2.2 The European Super Grid

Another project for a super grid in Europe is the European Super Grid (ESG). This grid should be planned on an international basis and is meant for long distance power transfers across Europe. Today's interconnected 400 kV system in Europe is based on national grids that have some cross-border coupling points [Schettler et al., 2012].

This development is partly going hand in hand with the NSSG activities, but is also partly independent. The North Sea region is a part of Europe and in a similar way the NSSG could be seen as a part of the ESG. This NSSG part of the ESG has gained special attention, due to the facts that it is offshore and that there is almost no existing electric power infrastructure in the region.

The ESG is finding acceptance in academic, industrial and political circles, just like the NSSG. However, the acceptance of extensions to northern Africa for the integration of solar power facilities in the Sahara has partly disappeared as a consequence of the recent political developments in the region.

More information about the ESG can be found in Publication IV.

2.2.1 Drivers

The development of the ESG has been promoted as a means or necessity to attain the ambitious renewable energy targets Europe has set.

2.2.1.1 The Pan-European Electricity Market

As mentioned in the previous subsection about the NSSG, strong interconnections are desired for energy trade. While the NSSG will couple three asynchronous AC systems, the ESG will mainly couple the already connected AC systems of continental Europe. But even though the continental European power system is already interconnected, the available transmission capacities are not sufficient at the moment for a large and efficient European electricity market. The concept of the pan-European electricity market demands transmission capacity in Europe on a scale that is not available at the moment. The ESG will significantly improve cross border trading capacity, reducing bottlenecks, leading to more dispatch flexibility and less congestion cost.

2.2.1.2 Balancing of Renewable Energy

The rising share of volatile renewable power sources, that are often concentrated in a few regions, leads to increasing power output fluctuations. This can create huge power flows over long distances in Europe, which need a more potent transmission infrastructure. A strongly interconnected ESG could help to balance those fluctuations even better than the NSSG, since the effect of the regional balancing approach increases with the size of the considered area.

Regarding wind power, the ESG would create a strong link between the large wind power facilities of the North Sea region and the Iberian peninsula. This would lead to a smoother total wind power system infeed, as the weather correlation between e.g. Portugal and Denmark is rather limited.

The same does also apply for solar power systems, because clouds are (just like wind) a regional phenomenon. This is however at the moment not as relevant yet, as half of the European solar power installations are concentrated in southern Germany, decreasing the possibility for balancing between different regions of Europe. It is likely that other regions of Europe will utilise solar power more in the future and e.g. Italy has seen a fast development of photovoltaic installations recently.

The ESG would also enable balancing across different renewable energy sources. The correlation between solar power output in southern Germany and wind power output in the UK is also limited.

2.2.2 Structure

The structure of the ESG will not be as complex as the NSSG. This is due to the fact that Europe already has highly developed onshore power grids in place. The ESG is therefore not a completely new multi-layer grid, but a new upper layer, that will be constructed 'on top' of all the existing grid structure.

It is not useful to redefine the existing structures of the European power systems as part of the ESG. All connection points between the ESG and the existing electric power infrastructure, will (from the ESG point of view) mostly appear as sources and loads.

2.2.3 Future Development

The ESG will likely grow as an extension of the NSSG. While the NSSG is transferring offshore power to shore, load centres are not necessarily close to shore. In Germany it is planned to extend the offshore wind power HVDC links far into the continent away from shore [50 Hertz Offshore GmbH et al., 2013].

The ESG will grow continuously and be constructed in a modular way, just like the NSSG. It will be difficult to define clearly what the NSSG and the ESG will be in the future. The NSSG will probably at some point disappear as a separate offshore grid, and it will just be the offshore part of the ESG.

2.3 Identification of Branches with Inherent Asymmetric Loading

Any electric power grid can have branches with inherent asymmetric loading. These are branches where full capacity can only be reached in one direction.

For this to appear, there needs to be a node with an overrated branch. A node is connected to N branches. Branch $a$is overrated with regards to a node (from a network point of view, neglecting generation and loads in the node), when its transfer capacity P_a is larger than the sum of the transfer capacity P_i of all other branches of that node together.

$$P_{a,\,\text{overrated}} = P_a - \sum_{i \neq a}^{N} P_i \tag{2.1}$$

If $P_{a,\,\text{overrated}}$ is positive, branch a is overrated.

The total generation capacity of the node is called P_{gen} and the maximum total load P_{load}.

- If $P_{\text{gen}} > P_{a,\,\text{overrated}}$ and $P_{\text{load}} > P_{a,\,\text{overrated}}$, branch a can be fully loaded in both directions.

- If $P_{\text{gen}} < P_{a,\,\text{overrated}}$ and $P_{\text{load}} < P_{a,\,\text{overrated}}$, branch a is really overrated (not only from a network point of view). The full capacity of that link can never be utilised, which raises the question if such a link would be built in reality.

- If $P_{\text{gen}} < P_{a,\,\text{overrated}}$ and $P_{\text{load}} > P_{a,\,\text{overrated}}$, branch a can only reach its full capacity when importing. It is overrated for exports and has inherent asymmetric loading.

- If $P_{\text{gen}} > P_{a,\,\text{overrated}}$ and $P_{\text{load}} < P_{a,\,\text{overrated}}$, branch a can only reach its full capacity when exporting. It is overrated for imports and has inherent asymmetric loading.

Branches with inherent asymmetric loading have therefore inherent unidirectional capacity: Transmission capacity which physically cannot be used to transfer power in reverse direction. This capacity can be designed to be unidirectional without degrading operational flexibility of the entire system.

The North Sea Super Grid (Section 2.1) will be a grid where branches with inherent asymmetric loading are very likely to appear (Section 2.1.5.3).

Inherent asymmetric loading results in asymmetric requirements for that branch. This is important for branches realised with HVDC technology (Section 2.4.2).

The details of this approach can be found in Publication III. In this publication, HVDC lines with inherent asymmetric loading have been referred to as ‘asymmetric HVDC links’. This term has been discarded for this thesis, as it was unclear to some readers. An asymmetric HVDC link could also refer to a monopole HVDC system where the mid-point voltage differs from zero, as opposed to a symmetric monopole.

There is also an estimation about the possible investment cost savings in Publication III, resulting from the consideration of asymmetry. It is also shown, based on computer simulations, that even less bidirectional capacity is needed under any realistic operational conditions.

2.4 Technology for Long Distance Transmission

Electric power transmission is generally possible with cables or overhead lines and with DC or AC technology, leading to four possibilities:

- AC cables
- AC overhead lines
- DC cables
- DC overhead lines

On land, both overhead lines and cables can be utilised, but for offshore applications only cables are possible. Both AC and DC technologies have been considered, but the focus of the European Super Grid projects and of this thesis has been on DC technology. The reasons for this choice are explained in this section.

2.4.1 AC Technology

AC overhead lines is the most proven of all transmission technologies and offers significant advantages to other transmission solutions. They might be an attractive solution for onshore super grids in large continental regions like Northern America or Russia.

However, there are three significant problems regarding AC-based super grids in Europe:

- The NSSG part of the ESG will have to be located offshore, where overhead lines cannot be constructed. AC cables face limitations for long distance transmission, (longer than ca. 100 km [Barberis Negra et al., 2006]), due to the high cable capacitance.
- Public opposition against transmission infrastructure with a large footprint is strong in Europe. To justify the name super grid, the capacity of the grid would need to be significantly larger than of the existing interconnected AC system in Europe, creating the need for very high voltages such as 750 kV. For this voltage level insulation distance in air is large, leading to overhead line pylons and transmission corridors much larger than those currently existing in Europe. In the recent political climate in Europe, it appears very difficult to realise such an AC-based onshore super grid in the near future.
- Several independent (non-synchronised) AC frequencies exist in northern Europe, which would need to be synchronised for the interconnection with AC.

The focus of the European Super Grid projects and of this thesis is on DC technology, due to these reasons.

2.4.2 DC Technology

HVDC is a recent field of research, and has gained a lot of attention in the last few years. Advances in semiconductor technology and HVDC converter design have led to HVDC being a good technical solution for a variety of tasks.

There are several technical factors that favour HVDC technology:

- HVDC can be used for long cables, and is therefore the only viable solution for long distance subsea transmission.
- HVDC can easily connect asynchronous AC areas.
- HVDC can achieve high power ratings.
- HVDC has low losses.
- HVDC does not have reactive current and power.

- HVDC overhead lines require less space and have a smaller footprint than AC overhead lines.
- HVDC converters (VSC) can stabilise the AC grid through dynamic reactive power support.

The first point regarding long distance subsea transmission has been the clearly dominating driver for most of the existing European HVDC links, which are offshore cables. Also the second point regarding the connection of asynchronous areas has been very important, and many European HVDC links connect two different AC areas. Transmission between Norway and continental Europe or between the UK and continental Europe is entirely HVDC. Also the connections to the ROWPP Bard Offshore 1 and to the Troll OGP and the Valhall OGP are HVDC.

There are also several non-technical factors in favour of HVDC technology:

- HVDC transmission corridors are less invasive to the landscape and are therefore better regarding public acceptance.
- HVDC is well suited for subterranean cable transmission systems, which have even less visual impact.
- HVDC is seen by many as a modern new technology, opposing the classical old AC technology.
- HVDC is often associated in a positive way with renewable energy, due to the HVDC cable connections for ROWPPs.
- HVDC technology is strongly supported by the manufacturers, as it is a newer and less mature market with larger profit margins.
- HVDC technology is a European export success and is therefore also supported by European politicians.

All the above reasons for the application of HVDC technology in Europe are not of technical nature, but they are highly relevant. Decisions regarding the power supply for the next century affect the entire population and are not just a technical issue.

Most existing HVDC systems are point-to-point transmission systems, which is a well established technology.

Multi-terminal HVDC schemes have been realised [Nakajima and Irokawa, 1999], but so far they have been complicated, not mature yet and they only have a small number of terminals. However this technology is emerging with new projects in the pipeline [Froejd et al., 2009] [Barker et al., 2012], that will give valuable experience needed for the construction of DC-based super grids.

A meshed HVDC grid with a large number or terminals has never been demonstrated. The technology to realise such a grid is not yet fully developed. Especially the protection of such a system is a major challenge. One should therefore not lose sight of other super grid options, like a sectioned super grid, where every section is limited in size (see also Section 2.6.3).

The creation of DC grids will lead to new requirements for HVDC technology, especially when it comes to multi-vendor compatibility. Standardisation will be crucial to realise multi-vendor DC grids, but (as very often in technology development) it is challenging to define valuable standards for new immature technologies.

The are two types of HVDC converters:

- Current Source Converter (CSC), Section 2.4.2.1
- Voltage Source Converter (VSC), Section 2.4.2.2

HVDC systems usually only utilise either CSC or VSC converters. Both technologies have some advantages and drawbacks. However, the focus of the European Super Grid projects (and of this thesis) is on VSC technology. The reasons for this choice are explained later in this section.

Hybrid HVDC Systems

A HVDC system, which contains both converter types, would be called a hybrid HVDC system and the concept was proposed in [Zhao and Iravani, 1994]. Hybrid HVDC could offer advantages for the connection of offshore power systems, especially for multi-terminal systems, where one onshore CSC terminal is connected to several smaller offshore VSC terminals [Pan et al., 2006]. The integration of existing CSC links into a future VSC-based super grid could also lead to hybrid structures.

The development of hybrid HVDC systems is still at an early stage and it has so far not been tested on a realistic scale [Zhao and Iravani, 1994] [Iwata et al., 1996] [Torres-Olguin et al., 2010]. This is mostly based on a lack of interest in hybrid HVDC systems. A brief assessment of hybrid HVDC for the utilisation in offshore grids can be found in Publication I.

Unidirectional HVDC Systems

Conventional HVDC systems are designed to be able to transfer power in both directions offering operational flexibility. As indicated in Section 2.3, this is not always needed. The NSSG is a pioneering project leading to new requirements for HVDC links.

The disadvantage of unidirectional systems is obvious: Power flow direction cannot be reversed. There are also possible benefits from unidirectional HVDC systems, and they should be considered, when bidirectional operation is not needed:

- The protection system can possibly be simplified, as current in the wrong direction can easily and immediately be identified as fault current.
- The current on the receiving end always crosses zero during a fault. The protection system can take this fact into account (possibly using diodes).
- A first prototype of a DC circuit breaker consists of a separate stack of IGBTs and anti-parallel diodes for each direction [Haefner and Jacobson, 2011].
- The receiving end converter voltage can be rated slightly smaller than the sending end converter, taking transmission losses into account.

The details of the benefits of unidirectional HVDC systems can be found in Publication III.

2.4.2.1 Current Source Converter

CSC HVDC technology (also known as line commutated converter) has been applied in many projects around the world for many decades. CSC technology has some relevant advantages:

- The CSC HVDC cable link with the highest power rating (1 400 MW) is in operation in Japan [Nakao et al., 2001], and a 3 000 MW connection between Java and Sumatra is under construction. For HVDC overhead lines even much higher power ratings have been achieved.
- The applied power electronic switching components are thyristors, that have low conduction losses. The switching frequency in a standard line commutated converter type CSC is as low as the electrical grid frequency, leading also to low switching losses. Additionally, CSCs can be operated at high voltages leading to lower transmission losses, resulting in excellent total efficiency.
- Due to the large number of CSCs that have been in operation for many years, the technology has a substantial track record and can be seen as mature and reliable.
- CSCs are robust to DC faults due to the absence of anti-parallel diodes at the switches. A CSC has a large DC inductor which automatically limits a possible DC fault current [Zhao and Iravani, 1994].

Even when regarding all these advantages of CSC technology, it will most likely not be the main technology for future super grids. This is mostly based on the nature of the CSC to operate with a constant DC current (direction and amplitude) and variable DC voltage (polarity and amplitude) regarding short time frames.

This variable-voltage property conflicts with the operational concepts of HVDC systems. A point-to-point system is operated at constant DC voltage amplitude and a grid is operated with a constant DC voltage amplitude and polarity.

This variable-voltage problem can be and has been addressed by sophisticated controls for two-terminal systems and even for two radial three-terminal systems in southern Europe [Collet Billon et al., 1989] and in north America [ABB] [Long et al., 1990]. For a large meshed DC grid though, control is likely to get very complicated.

This problem results in the dynamic bidirectional performance of the CSC being rather poor. From a power flow perspective, a CSC-based HVDC converter station is a bidirectional device, that can transfer power in both directions. From a dynamics point of view it is a unidirectional device, that can only operate in one quadrant and transfer power only in one direction. To achieve a power flow direction reversal, either the voltage polarity or the current direction has to be reversed.

- A change of the voltage polarity is the common solution for point-to-point HVDC systems. To reverse the voltage polarity, the system has to be powered down, and restarted with reversed polarity. A ramped power reversal would have to be done in the following way: Ramping current down to zero and back up again, and instantaneously changing the voltage polarity at the exact moment when the current is zero. This instantaneous voltage polarity change cannot be performed in reality.

- A change of the current direction is therefore the only realistic option for HVDC grids. It would not be realistic to reverse the voltage polarity of an entire DC grid, just to enable one converter to change the power flow direction. To reverse the current direction, the system has to be powered down and the converter has to be disconnected and reconnected with reversed DC terminals. This can (of course) also not be done instantaneously.

The complete operational frame (for operation in a grid with fixed voltage) is given in Table 2.1 and it clearly shows the difference between static and dynamic operation.

The large size of a CSC converter station is another disadvantage. A large share of the total size is due to the equipment for harmonic filtering and reactive

Table 2.1: CSC HVDC operational characteristics

	Static	Dynamic
Voltage polarity	Fixed	Variable
Voltage amplitude	Fixed	Variable
Current direction	Variable	Fixed
Current amplitude	Variable	Fixed

power compensation. Typically, the reactive power consumption of a CSC is about 50 % of the active power transfer [Jonsson et al., 1999]. Filtering is usually required from the 11th harmonic upwards and tuned harmonic filters with large capacitor banks have become the standard solution. This large size is problematic in highly populated areas, and very problematic offshore.

A CSC station needs a strong AC grid to connect to, as a stiff AC voltage is required for successful commutation [Jonsson et al., 1999] [Xu and Andersen, 2006]. This is problematic for the connection of weak offshore grids. A CSC cannot be used to black start an (offshore) AC grid.

Due to these reasons, the focus of the European Super Grid projects and of this thesis is on VSC technology.

2.4.2.2 Voltage Source Converter

VSC technology has seen very fast developments and technology improvements in the last decade. The advantages of the CSC to the VSC (high power, low losses, high reliability) are shrinking due to the technical progress of the VSC. The applied power electronic switching components are insulated gate bipolar transistors.

The first VSC HVDC system (Haellsjoen link) was installed by ABB in Sweden and commissioned in 1997 [ABB]. Several other systems have been installed in recent years. Today the power rating goes up to 400 MW (BorWin1 link), but 800 MW systems (DolWin1 link) are in the pipeline. On the ABB website [ABB], the technology is proposed to up to 1 200 MW, but even higher ratings have been mentioned less formally. All offshore HVDC projects today use VSC technology.

Most existing VSC HVDC systems are basic two-level converters. The introduction of the Modular Multi-level Converters (MMC) probably is the most significant recent development regarding VSC HVDC technology. MMC technology is very likely to dominate in the future, because it can offer lower switching losses and increased power quality [Lindberg and Larsson, 1996]. The first 400 MW multi-level converter based HVDC system (Trans Bay Cable), has been installed by Siemens in 2010 and an 800 MW multi-level system (BorWin2 link) is to come [Siemens].

VSCs operate at fixed DC voltage (polarity and amplitude) and variable DC current (direction and amplitude). This operational characteristic is not depending on the time frame addressed, as seen in Table 2.2. The VSC is fully bidirectional and the power flow direction can easily be reversed by changing the direction of the DC current.

The fixed DC *Voltage* characteristic of the *Voltage* source converter is highly advantageous for fixed *Voltage* DC systems. It makes it possible to easily connect several converters to the same DC bus or grid. This feature is advantageous for multi-terminal applications and superior for meshed grid applications.

Table 2.2: VSC HVDC operational characteristics

	Static	Dynamic
Voltage polarity	Fixed	Fixed
Voltage amplitude	Fixed	Fixed
Current direction	Variable	Variable
Current amplitude	Variable	Variable

VSCs can form their own AC voltage and therefore connect to weak AC grids, electrical islands or even passive networks. This is especially interesting when connecting to ROWPPs or OGPs. The black start capability is important for systems which lack generators with that ability.

VSCs can produce or consume reactive power independently from active power. Since reactive power compensation is not needed, and filtering requirements are low or even zero (for some MMCs), VSC stations can be constructed in a compact way [Barker et al., 2009].

Due to these characteristics, VSC HVDC technology is generally regarded to be the technology of the future and the best choice for realising super grids (especially offshore) [Cole and Belmans, 2009] [Bresesti et al., 2007].

One relevant disadvantage of the VSC is that DC fault handling is difficult. If the DC voltage drops below the AC peak voltage, the converter's diodes start conducting. In this situation the converter behaves like an uncontrolled diode rectifier and feeds energy to the fault. There are however special VSC topologies (e.g. MMC with four-quadrant modules), where this problem does not apply.

A comparison of the main differences between VSC and CSC technology is given in Table 2.3. A more detailed overview can be found in [Agelidis et al., 2006].

Table 2.3: Comparison of HVDC technologies

Technology	VSC	CSC
Semiconductor	Transistor	Thyristor
Largest cable system	400 MW	1 400 MW
Largest cable project	800 MW	3 000 MW
Power rating	Low	High
Voltage rating	Low	High
Losses	High	Low
Bidirectional operation	Yes	Difficult
Reactive power control	Yes	No
Converter size	Small	Large
Filters	Small	Large
Black start	Yes	No
Multi-terminal	Yes	Difficult

2.5 Technology for Offshore Nodes

The offshore nodes in a super grid are offshore cluster grids, and the nodes in an offshore cluster grid are ROWPP collection grids or the internal grids of OGPs. An offshore cluster grid connects several ROWPPs together and also integrates offshore loads. The WPP collection grid connects all the wind turbines in a WPP to a common collection point which can be a transformer or converter station.

Both cluster grids and WPP collection grids can be realised with AC or DC technology.

2.5.1 AC Technology

AC technology is the state of the art and is generally mature. This choice is advantageous, since a lot of components are available. AC circuit breakers are especially important, since they enable reliable and cost effective protection and sectioning schemes.

2.5.1.1 Collection Grids

The state of the art regarding collection grids for WPPs is AC technology, and it is so far applied in all existing WPPs. This choice is convenient for regular onshore or near-shore WPPs, taking into account, that the WPPs are connected to an AC power system. This AC power system frequency serves as a reference for, and is the same as, the collection grid frequency.

ROWPPs with HVDC interconnection are a special challenge, since they must be operated as electrical islands with their own frequencies, which are not linked to the frequency onshore. As no single wind turbine can force a frequency upon the grid, the reference frequency is usually set at the common collection point (from a converter there or from a higher grid level).

Modern wind turbine concepts mostly use doubly fed electric machines (often also called doubly fed induction generator) or synchronous generators with full scale back-to-back AC-DC-AC converters. In both cases, there is no link between the rotational speed of the turbine and the electrical frequency of the collection grid.

The offshore grid frequency is neither linked to the rotational speed of the generators nor to the frequency of the onshore grid; it is in fact not linked to anything, and it can be chosen freely. Of course 50 Hz would be a convenient choice, since a lot of existing devices could be applied, but also zero (DC) is a valid choice.

The absence of a direct connection to an electric machine makes such a collection grid inertia-less, which is the basis for very fast desired and undesired frequency changes. This gives rise to special challenges, and the operational experience for regular AC grids cannot directly be transferred. The amount of operational experience, knowledge and literature about purely power converter based inertia-less AC grids is limited. Control schemes for the operation of parallel inverters have been developed [Hauck and Spaeth, 2002], but have so far only been applied on a small scale. The feasibility for real life systems is being demonstrated at the Bard Off-shore 1 ROWPP in Germany, but it is unlikely that important control details will be made public.

2.5.1.2 Cluster Grids

Since the WPP collection grids are usually realised with AC technology, it is convenient to realise a cluster grid also with AC (if the WPPs have the same frequency). WPPs that have been constructed as stand-alone systems with their own frequency, will have to adapt to synchronising with the other WPPs when they are integrated into an AC cluster grid.

An offshore AC cluster grid with several WPPs will probably also have several HVDC converter stations, that extract the produced wind power. The cluster grid therefore does not have a central collection point like a collection grid, that can serve as a natural frequency reference point. If the chosen cluster grid frequency is set by a single HVDC converter station, control is easy but vulnerable if that reference unit has a failure. With increasing size of the cluster, the reference unit becomes smaller in relation to the entire cluster, which could lead to stability issues.

ROWPPs with DC collection grid and a DC-HVDC converter station would need an extra converter to be able to connect to the AC cluster grid. The same applies for ROWPPs which use a different frequency.

2.5.2 DC Technology

DC technology offers some interesting advantages and might gain importance in the future. There are no reactive power flows, losses are smaller and the there is no need for a third conductor.

2.5.2.1 Collection Grids

Regarding ROWPPs, the choice for an AC collection grid is not straightforward, as grid integration is realised with HVDC transmission. For wind turbines with synchronous generators the variable frequency AC output is directly rectified to DC and then inverted back to AC of the desired frequency. Considering turbine output being DC (after the first converter stage) and transmission being DC, it is a logical consequence to question if an intermediate step to AC for the collection grid is needed and useful.

For HVDC connected ROWPPs the all-DC concept seems promising, since it avoids unnecessary conversion steps. The feasibility of DC collection grids has been studied in the literature and might gain importance in the future [Meyer, 2007] [Max, 2009]. To realise that type of solution, a high power DC-HVDC converter is needed. At present high power DC-HVDC converters seems feasible, but they have never been realised, as there was no need for them so far.

2.5.2.2 Cluster Grids

ROWPPs with HVDC connection always have a HVDC converter (AC-HVDC or DC-HVDC, depending on the collection grid). That existing HVDC converter station could possibly be used to connect to a HVDC cluster grid instead of the connection to shore.

ROWPPs with an AC collection grid could also maintain their own frequency, avoiding the need for synchronisation.

The DC solution might offer significant advantages for large remote offshore clusters. Nothing similar has been built yet and the operational experience with DC grids is still limited, which makes AC a more attractive technology for this task today. On the other hand, the construction of large offshore clusters is not happening today, so DC technology might improve and become mature in the meantime and be ready when it is needed.

In the future, when several DC cluster grids are interconnected with several HVDC transmission lines, cluster grids and long distance transmission might merge to a single structure, dissolving the distinction between levels III and IV as mentioned in Section 2.1.2.

2.6 Structures with Multiple HVDC Links

The future projects in the North Sea will lead to a high concentration of HVDC cables and converters. The number of offshore installations to be connected, as well as the total power rating of the installations, and the general complexity will exceed present HVDC systems by far.

The increasing number of offshore installations demands radial connected lines, where several offshore converters are coupled to the same DC cable. The expected power ratings of the largest ROWPPs will exceed the power transfer capability of a single HVDC cable pair, leading to parallel connected HVDC cables. A combination of both would lead to a meshed grid structure. This would offer several advantages, as it is the case with onshore AC grids, but new challenges come along with meshed DC grids.

2.6.1 Radial Connection

Several HVDC links can be connected radially leading to a multi-terminal HVDC system (shown in Figure 2.8). These systems are favourable, when several smaller offshore installations (especially OGPs, that have a significantly lower power rating than ROWPPs) have to be connected, if a single HVDC bipole or symmetric monopole is powerful enough to serve all [Haileselassie et al., 2008] [Hendriks et al., 2007].

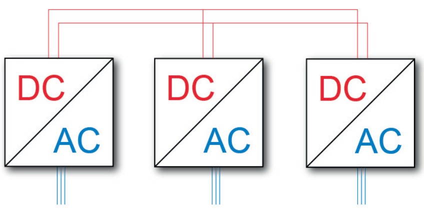

Figure 2.8: Radial connected HVDC systems

Radial connected HVDC systems are possible using both converter types (CSC and VSC). This has been proven by the operational systems using CSC (Canada - USA) [Long et al., 1990] [ABB] and (Mainland Italy - Corsica -

Sardinia) [Collet Billon et al., 1989] and also for VSC (Japan) [Nakajima and Irokawa, 1999]. A second VSC HVDC link with radial connected lines is in the pipeline (Sweden - Norway) [Barker et al., 2012].

Even though both converter types are possible for multi-terminal operation, VSC still offers significant advantages, due to the fixed voltage polarity (as discussed in Section 2.4. The existing VSC-based multi-terminal system demonstrates the feasibility, but it should not be taken as a reference for the technical possibilities of such systems. Semiconductor and converter technology have improved significantly in the last decade, implying that future multi-terminal HVDC systems will outperform the existing ones [Barker et al., 2012].

The radial connection had been referred to as series connection in Publication II. This was changed to 'radial' in this thesis, as it was experienced that 'series' was unclear to some readers. A radial connection is a series connection of transmission lines. Series connected HVDC could also refer to series connected HVDC converters (leading to increased voltages) instead of series connected transmission lines, and the term has therefore not been used in this thesis.

2.6.2 Parallel Connection

The size of some planned ROWPP clusters (like the Dogger Bank [Forewind]) exceeds the technical possibilities of a single HVDC cable pair. Reliability requirements also oppose the use of single systems for important transmission corridors. It is not only the power capability of an HVDC link which limits the possibilities, but also the primary reserves of the connected onshore grid. Even if HVDC cable ratings would significantly rise in the future, single installations with high power ratings (above circa 1 500 MW) will remain problematic.

The blocks of the Civaux nuclear power station in France have the highest electric power rating (1 561 MW) in the world at the moment [IAEA]. The primary frequency control reserves are partly determined by that power rating. The continental European power system provides primary frequency control reserves of 3 000 MW [Rebours and Kirschen, 2005], which is approximately the loss of two of the largest blocks.

The introduction of HVDC converter stations with a higher rating than circa 1 500 MW would call for a general reassessment of the system operation practise.

HVDC links up to 10 000 MW have been proposed in system studies [Groeman et al., 2008], without regarding technical details. A failure of such an HVDC link would have an unacceptable impact on the connected onshore systems. Such a link therefore has to consist of several parallel systems, to avoid the possibility of a loss of the entire link at once.

Parallel HVDC connections (shown in Figure 2.9) do not only increase the total power transfer capacity, but also add important redundancy at the same time, keeping the maximum disconnected power in case of an outage within acceptable limits (1 500 MW). Links can be seen as parallel, if they connect the same offshore cluster to the same onshore grid, not depending on the exact geographic location of the cables.

Studies such as [v. Hulle et al., 2009] have proposed parallel HVDC links for wind integration, but the matter was treated from an economic point of view and not in technical detail.

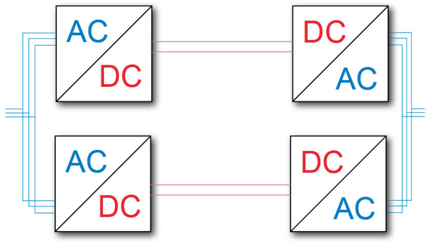

Figure 2.9: Parallel connected HVDC systems

The continental European and the Nordic power systems are coupled via several parallel HVDC links. Both of these AC systems are strong, which makes the operation of the HVDC connectors rather easy compared to the connection to offshore installations. Up to now no offshore facilities exist, that exceed the power capabilities of a single HVDC link, but this is likely to change in the future. A HVDC project in Sweden is in the pipeline, which will be two parallel HVDC circuits [Barker et al., 2012].

Parallel HVDC systems are especially interesting, when they have inherent asymmetric loading (Section 2.3). In that situation, some of the HVDC systems could be designed to be unidirectional (Section 2.4.2), while others are bidirectional. The maximum power transfer capacity of the entire link would depend on the direction, and could be 'tailor-made' for the actual demand. For the unidirectional systems, even a CSC or hybrid HVDC link could be possible, since the mentioned disadvantages with bidirectional operation do not apply here. More about the possible benefits can be found in Publication III.

2.6.3 Meshed Connection

If several HVDC links are connected to a meshed grid structure (shown in Figure 2.10), the properties of parallel and radial connected HVDC links are combined. A possible HVDC grid would be able to integrate a large amount of power, include many offshore installations and support $N-1$ secure operation.

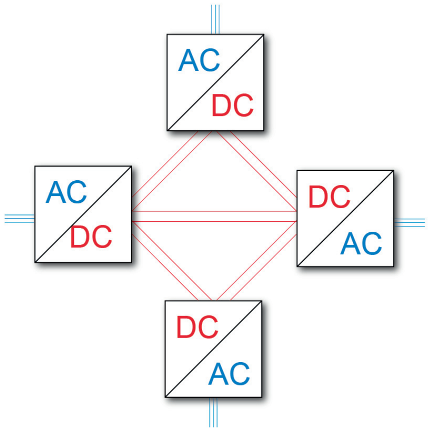

Figure 2.10: Meshed HVDC grid

With all the advantages a meshed HVDC grid would provide, the technology for such an application is still under development and it is facing some serious challenges, especially when it comes to system protection and fault handling [Pawani et al., 2012].

Another practical challenge that needs attention is the standardisation of equipment ratings (especially the DC voltage) and the determination of 'grid codes' to manage the requirements for HVDC terminals that are to be connected to the grid.

The power flow in a meshed grid cannot easily be controlled. While phase shift transformers enable precise power flow control in AC grids, similar voltage shift devices would be needed to control the DC power flow. An interesting topology for that has been proposed in [Barker and Whitehouse, 2012b].

Meshed Grid with Super Nodes

The mentioned challenges with a meshed HVDC grid can be avoided with a 'work-around'. This solution involves the utilisation of so-called super nodes. This alternative super grid concept is entirely based on proven technology.

A super node is not a regular node as it is known from network theory. All branches that connect to a super node are not directly connected to each other, but they all only connect to the super node. This super node has a structure itself, and therefore it is not a simple point in a network.

AC technology can be used within offshore clusters and DC for long distance transmission. These offshore cluster appear as super nodes when all HVDC links only connect to the AC cluster and not to other HVDC links. This way the 'meshed grid' can be achieved with only point-to-point HVDC systems. In reality it is not a meshed grid, but a large number of two-terminal HVDC systems that connect several isolated AC clusters.

Fault handling and system protection could be based on proven concepts for such a system. Standardisation of the DC voltage is not necessary, as all HVDC links are allowed to have their own voltage. The power flow is fully controllable, since there are no loops in the network.

The main disadvantage of this approach is the increased losses for very long distance transmission. The transferred power is converted DC-AC-DC every time it passes a node of the super grid. For a large super grid with many nodes, this is hardly acceptable. The total number of HVDC converter stations is also higher than for a regular meshed DC grid.

2.7 Reliability Assessment of HVDC Grids

A reliable power supply with high power quality is a main advantage of high-wage industrial countries. Outages in the electric power supply pose the risk of severe economic impacts on society.

Unlike the existing HVDC systems in Europe, a future HVDC grid will be crucial for the AC grids connected to it. Therefore reliability has to be much higher compared to regular HVDC systems. To be able to study the reliability of future HVDC grids, the available tools for reliability analysis have been studied, and a comprehensive overview has been published in Publication V.

To perform a valid reliability analysis, the component reliability data of the grid assets have to be known, no matter which reliability assessment method is to be used. A future HVDC grid will be mainly based on new technologies like MMC and DC circuit breakers. These technologies do not have a substantial track record, which would be used to determine the needed component reliability data. Therefore the component reliability data can only be estimated.

This estimation has been done in [Linden et al., 2010]. There it is shown, that the reliability of a point-to-point HVDC system is mainly depending on the reliability of the converter transformers. The component reliability data of the HVDC converter transformer were estimated to be identical with the data of a regular AC power transformer. This assumption might be a valid first approximation, but influences like converter switching harmonics might degrade the transformer reliability [Mora-Florez et al., 2008]. Also a location offshore might degrade reliability by making access, maintenance and repair more complicated.

It has been concluded that the approach presented in [Linden et al., 2010] is a first step towards reliability assessment of HVDC grids. It has also been concluded that for going further and performing more detailed and accurate studies, the input data are still missing. Replacing the missing input data with assumptions makes the outcome of the analysis and the validity of the entire approach somehow questionable. This approach has therefore been discontinued. It will become an important field of research, when more data on the core technologies for (offshore) DC grids will be available.

2.8 HVDC Grid Test System

Several fields of research regarding HVDC grids rely strongly on computer simulations to develop, test and verify new concepts. Unlike AC system research, no real power grid can be taken as a reference for simulation, so artificial DC power systems have to be simulated.

Most research projects use their own small and simple DC grid test systems. These systems consist often of just a few terminals, as the main focus of the publications is on the developed new concepts and not on the DC system they are applied on.

As these small and simple test systems might not reflect a future DC grid very well, relevant phenomena might not be captured by them, possibly leading to false conclusions. Therefore a good and detailed DC grid test system for computer simulation has been identified to be crucial for the research community, by the author of this thesis but also by the CIGRE working groups involved in DC grid research.

CIGRE B4 has decided to develop a reference DC grid test system, which could be used for a variety of different studies. The aim is to make different concepts comparable when applied on the same standard test system. Its purpose is to have a common reference for studies concerning DC grids, within and also outside CIGRE B4.

The author of this thesis, who is involved in CIGRE B4 working groups B4-57 and B4-58 has been leading and coordinating the development of the 'CIGRE B4 DC Grid Test System'. A detailed description of the test system can be found in Publication VI.

In Publication XIII, an outdated version of the CIGRE B4 DC Grid Test System is shown. However, it is this version, that has been used in Section 4.5.

2.8.1 System Description

The basic structure of the test system is shown in Figure 2.11.

The complete system is composed of:

- Two onshore AC systems

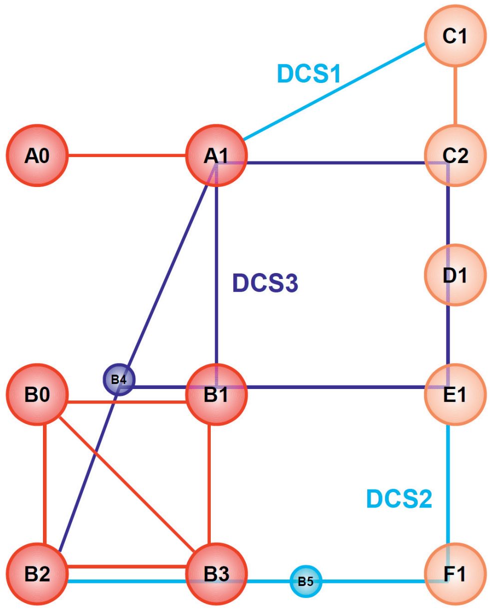

Figure 2.11: The CIGRE B4 DC Grid Test System (schematic)

  - System A (A0 and A1)
  - System B (B0, B1, B2 and B3)
- Four offshore AC systems
  - System C (C1 and C2)
  - System D (D1)
  - System E (E1)
  - System F (F1)
- Two DC nodes, with no connection to AC
  - B4
  - B5
- Three VSC-DC systems
  - DCS1 (A1 and C1)
  - DCS2 (B2, B3, B5, F1 and E1)

– DCS3 (A1, C2, D1, E1, B1, B4 and B2)

A more detailed presentation of the test system is shown in Figure 2.12. All line lengths are given in km. A line drawn in Figure 2.12 represents a line circuit meaning three lines for AC and two lines for DC.

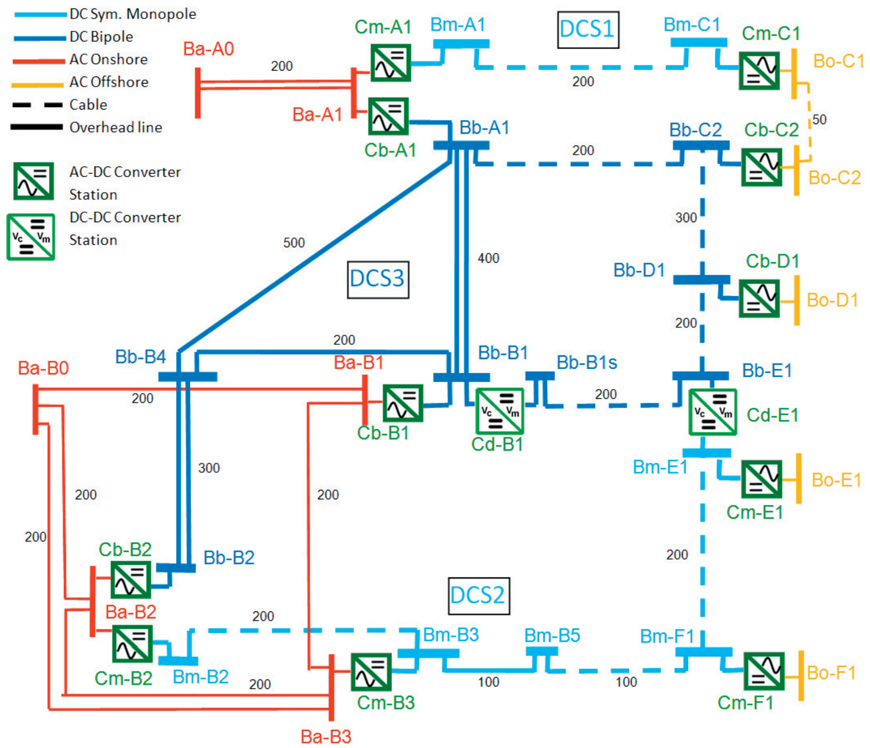

Figure 2.12: The CIGRE B4 DC Grid Test System (detailed)

Onshore AC busses are called ‘Ba’, offshore AC busses ‘Bo’, symmetric monopole DC busses ‘Bm’, bipole DC busses ‘Bb’, monopole AC-DC converter stations ‘Cm’, bipole AC-DC converter stations ‘Cb’ and DC-DC converter stations ‘Cd’.

AC System A consists of two busses, bus Ba-A1 where two AC-DC converters are located and slack bus Ba-A0 representing the rest of system A. System A has an active power surplus and exports electric power. AC system B consists of four busses, Ba-B1, Ba-B2 and Ba-B3 being connected to AC-DC converters and slack bus Ba-B0 representing the rest of system B. AC System B imports active power. AC systems C, D and F are ROWPPs and AC system E is an OGP.

DCS1 is a two-terminal symmetric monopole HVDC link (± 200 kV). It connects the ROWPP at C1 to the onshore node A1.

DCS2 is a four-terminal symmetric monopole HVDC system (± 200 kV). It connects the ROWPP at F1 and the offshore OGP at E1 to the onshore node B3 and extends further inland to a load centre B2. This system consists of overhead lines and cables in series, to be able to capture possible interactions of these different line types (wave reflections, etc.)

DCS3 is a five-terminal bipole HVDC meshed grid (± 400 kV). DCS3 contains a DC-DC converter at B1 for power flow control.

There is no direct connection between DCS1 and DCS2. DCS1 and DCS3 are interconnected through AC node at A1 (and somehow also through system C). DCS2 and DCS3 are interconnected through a DC-DC converter station at E1 and through an AC node at B2.

Any of these three DCSs can be used separately for tasks where the full test system is too complex. The DC-DC converter station within DCS3 at B1 can be bypassed if that is desired (it changes the power flow). The DC-DC converter station that connects DCS2 and DCS3 at E1 cannot be bypassed but it can be removed (disconnecting DCS2 and DCS3 at E1).

All three direct current systems are based on VSC technology. The two voltages (200 kV and 400 kV) are nominal voltages and they represent 1 pu voltage. The operational frame for the direct current systems has the upper limit at 1,05 pu and the lower limit at 0,95 pu.

A monopole AC-DC converter station consists of one AC-DC converter pole. A bipole AC-DC converter station consists of two AC-DC converter poles. The bipole DC voltage is twice as high as the symmetric monopole DC voltage, giving all converter poles in the system the same DC voltage (to make modelling easier).

2.8.2 Limitations

Average value models for electromechanical transient studies are given in Publication VI. The test system has also already been implemented in several electromagnetic transient simulation tools, but at the moment these electromagnetic transient models are not yet finalised. Electromagnetic transient models will later be given in the technical brochure B4-57.

The focus of the system is to study the DC systems and the converter control. Therefore it was decided to not model the AC generators and loads in detail in the first instance and they are simply represented by constant active power sources and sinks.

Only symmetric operation is regarded, so all ground currents are zero. All data given refer to positive sequence. For simulation grounded neutral can be utilised although a real future system probably will have a dedicated metallic return.

2.9 Summary

The changing requirements towards the electricity transmission infrastructure in Europe lead to a high demand for modernisation. The large-scale deployment of renewable energy sources probably is the strongest driver for electric power transmission infrastructure investments. The construction of a HVDC-based super grid is seen by many as the future solution for large-scale long distance electric power transmission.

The most critical region of Europe is the North Sea, as there is large-scale deployment of ROWPPs and almost no existing electric power infrastructure. The planned North Sea Super Grid will likely be the first HVDC-based super grid, making it a technology pioneering project. The NSSG is likely to extend also onshore towards the inland load-centres, eventually becoming the ESG.

When electric power infrastructure will exist in the North Sea region, this will be beneficial for all future offshore projects. For future ROWPPs and OGPs, it will significantly shorten the distance to the closest connection point. This in turn will significantly reduce the effort and cost of a cable connection.

Remote offshore OGPs would be more efficient, attractive, economical and environmentally friendly, if they could connect to an existing electricity grid in the North Sea. OGPs and their foundations, which are permanently taken out of service, could possibly still be used as offshore electrical nodes.

HVDC technology has significant advantages for high power long distance transmission, especially when power cables are used instead of overhead lines. Since overhead lines cannot be applied offshore, HVDC is the best technology for the NSSG and the ESG.

The ROWPPs which are under construction now are realised with internal AC grids. The NSSG will therefore consist of both AC and DC technologies and could be seen as a hybrid (neither AC nor DC) grid, but the share of those technologies is not known yet.

Meshed grid structures offer most advantages for super grids, but they also lead to the greatest challenges.

Chapter 3

Balancing Control of AC Power Systems

In this chapter, the interactions between power systems and power electronic assets are discussed with regard to power system balancing. The behaviour of power electronic systems in an electric power grid is mostly determined by its controls (under normal operation). Therefore a special focus in this chapter has been put on the control systems.

Even though the main focus of this thesis is on HVDC-based super grids, the general control interactions of power electronics in AC grids have been studied, as this is relevant for HVDC converter control regarding the interface between AC and DC grids. There are significant similarities between today's onshore AC systems and the future offshore DC systems in how power electronics influence the grid operation and stability.

The NSSG will be based on power electronics. The challenges regarding balancing will therefore be of a similar nature for AC and DC grids, and so will be the importance of proper control design. The study of the effects of power electronics control systems on AC onshore power system stability is useful. The lessons that can be learned are also valid for the future NSSG.

A well-defined system behaviour of all system relevant components is crucial for stable operation. This applies in a similar way to components with small number and high power (e.g. HVDC converter stations) and to components with a large number and a low power (e.g. plug-in electric vehicles).

This chapter is organised in seven sections:

Section 3.1	The basic operational principles of AC grids are explained, and some information about grid frequency fluctuations is given.
Section 3.2	The basic mechanisms for frequency control in AC power systems are explained.
Section 3.3	The grid frequency stability challenges resulting from power electronic assets are discussed.
Section 3.4	The grid frequency model, which has been used in this chapter, is described briefly.
Section 3.5	The grid frequency stability threat, which is imposed mostly by photovoltaic systems in Germany, is treated.
Section 3.6	A new control method for power electronic grid assets, that includes frequency response, is described.
Section 3.7	The summary of this chapter.

This chapter is based on Publications VII - X.

3.1 Balance in AC Power Systems

The balance in AC power systems is usually referred to as an active power balance. The balance indicator is the grid frequency. An imbalance in the active power balance leads to a deviation of the grid frequency (see also Section 3.2.1.1). The relationship between grid frequency and active power is non-linear.

Frequency stability in AC grids is important, since operation at an inappropriate frequency can lead to problems for rotating electric machines. Also fast changes of the frequency impose stresses on rotating electric machines. Furthermore, numerous frequency related settings are used in protection devices, e.g. under-frequency load shedding schemes.

Grid Frequency Fluctuations

The grid frequency is subject to fluctuations around the nominal frequency (50 Hz) at all times. These regular frequency fluctuations (noise) are usually quite small ($\Delta f < \pm 0,05\,\mathrm{Hz}$). In the continental European power system, these fluctuations can be stronger at exactly full hours ($\Delta f \approx \pm 0,1\,\mathrm{Hz}$). This is due to the hourly traded electricity at the European Power Exchange and the schedule changes of power plants [Weissbach and Welfonder, 2009].

The grid frequency of the continental European power system on 2010.12.22 is shown in Figure 3.1. The frequency spikes are most prominent during ramp times in the evening (hours 20-23) and morning (hours 6-8).

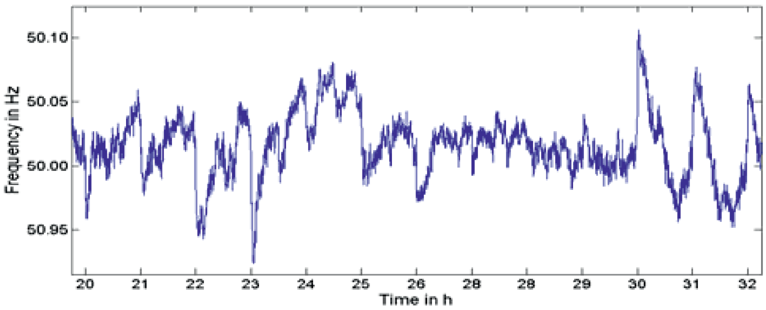

Figure 3.1: Hourly grid frequency spikes

3.2 Basic Frequency Control Mechanisms

The frequency response of an AC power system shows PID-characteristics [Kundur, 1994].

- D-behaviour ($\Delta P \sim s \cdot \Delta f$) means that there is a change of power proportional to the rate of change of the frequency. This behaviour comes from the rotating masses which provide inertia to the electric power system. Acceleration of the inertia causes the change in power. This relation is actually not proportional, but is usually considered linearised at the operating point in a small frequency range around 50 Hz. The differential part limits the rate of change of frequency, preventing steps or fast changes of the frequency.
- P-behaviour ($\Delta P \sim \Delta f$) means that there is a change of power proportional to the change of the frequency. This behaviour comes from primary control as well as the frequency dependency of loads [Kurth and Welfonder, 2006]. The primary frequency control is not completely proportional, as it usually is operated with a dead-band. The frequency dependency of loads is also not really proportional, but depends on the mechanical loads connected to the electric motors. Again, linearised conditions are usually applied also here. The proportional part keeps the frequency within a narrow margin.

- I-behaviour ($\Delta P \sim \frac{1}{s}\Delta f$) means that there is a change of power proportional to the integral of the change of the frequency. This behaviour comes from the secondary control. The integral part is concerning longer time frames (above one minute) and slowly restores the nominal grid frequency (50 Hz) after the post-disturbance steady state has been reached. I-behaviour is not addressed in this thesis as it is not relevant for the subjects treated.

3.2.1 Self-Regulating Effect

The self-regulating effect is the combination of the inertia and the frequency dependency of the load. It is instantaneous and always available. This important stability mechanism cannot be influenced directly.

3.2.1.1 Rotating Inertia

The inertia is based on the physical properties of all rotating electric machines (generators and motors) directly connected to the grid. The rotors of electric machines have inertia, and the rotating mass appears as important energy storage capacity. It prevents fast changes of the rotational speed of the machine.

The electrical grid frequency is linked to the rotational speed of the electric machines. The inertia therefore also prevents fast changes of the grid frequency. It can be seen as a physical feedback loop, where a power imbalance leads to a change in frequency, which in turn leads to a change in power in all electric machines.

This energy storage is able to handle short-term power imbalances. Short-term relates to the mechanical system time constant (aggregated time constant of all machines). The speed requirements of the system frequency controls are partly determined by this time constant.

The existence of inertia is the basis of frequency stability of AC power systems. The inertia is determined by the physical construction of the rotating electric machines, and is usually not be optimised for grid stability.

3.2.1.2 Frequency Dependency of Loads

Mechanical loads are usually directly connected to the electric power systems via the shaft of an electric motor. The power consumption of these mechanical loads (e.g. a fan or compressor) depends on the rotational speed of the motors, and therefore also on electrical grid frequency.

This is a very important balancing mechanism, as it automatically reduces the total system load in case of under-frequency condition. The frequency dependency is determined by the physical properties of the mechanical loads, and cannot be optimised for grid stability.

3.2.2 Primary Frequency Control

Primary frequency control is mainly provided by large thermal electric power generation units. It can directly be influenced via the controllers of those power stations. It needs up to 30 s to ramp-up, which leads to a sub-optimal transition (frequency dip) from pre-disturbance to post-disturbance state.

From a steady state perspective (disregarding the ramp-up time) it has a similar effect on the frequency stability as the frequency dependency of the loads. It is however 'stiffer' making frequency deviations in case of a disturbance significantly smaller than they would be with only the effect of the frequency dependent loads.

3.2.3 Load Shedding

Under extreme emergency conditions when the reserve power mechanisms are not capable of balancing production and consumption, under-frequency load shedding is the last option to keep the grid frequency within admissible boundaries. This is usually done stepwise in the grid frequency range of $49 - 48\,\mathrm{Hz}$.

3.3 Frequency Control Challenges with Power Electronic Assets

There is a strong trend towards 'modern' grid assets that connect to the grid via a power electronic converter interface. These power electronic systems have gained a significant share of all grid components and they often substitute classical (directly connected) electric machines.

- On the generation side, all photovoltaic systems and many wind turbines are connected to the AC grid through a power converter interface. These renewable sources partly substitute classical thermal power stations.
- On the load side, variable speed electric drives have decoupled the electric machine from the grid by a power converter. All kinds of electronics operate internally on DC and therefore need a power converter interface for grid connection. The rise in the use of the Plug-in Electric Vehicle (PEV), which is expected in the near future, will increase the share of power electronic loads even more.

This transition brings up challenges regarding frequency stability. Power electronic systems simply do not have the self-regulating effect: The power consumption/infeed is not a function of the grid frequency.

- From a load point of view, this property is brilliant. The power can be exactly controlled as desired, and it is not disturbed by external influences like the grid frequency.
- From a system point of view, this is a real problem. The self-regulating effect, which is inevitable for frequency stability, is missing.

Additionally, the substitution of classical thermal power stations by renewable sources could also at some point become a challenge for primary frequency control, which often is provided by thermal stations.

All these challenges will grow in the future as the trend towards power electronic converter systems is expected to continue. The increasing share of volatile generation units is adding to the problem, which might lead to a doubled demand for balancing power reserves by 2040 [Horbaty and Rigassi, 2007].

3.3.1 The Importance of the Control System

The behaviour of modern power electronic assets under normal operating conditions is mostly determined by its controls. The converter topology and physical realisation determine the limits for the normal operating conditions and the behaviour outside the normal operation range.

The rising share of power electronic components is endangering grid stability due to the absence of the self-regulating effect. At the same time, power electronic systems like the static synchronous compensator have been applied to improve grid stability. This shows that no easy answer can be found to the question of whether power electronics degrade or improve system stability.

The serious incidents affecting the continental European grid in 2003 [Vandenberghe et al., 2004] and 2006 [Maas et al., 2007] have shown that critical system conditions are worsened by converter systems with improperly designed control units. However, it is possible to design converter system controllers in a way that avoids these problems [Strauss and Meyer, 2005]. The design of the power electronics' controller determines whether a power electronic converter system is 'grid-friendly' or not.

Different control concepts have been proposed, how dispersed generation units could take part in frequency support. A controller for doubly fed electric machine based wind turbines, that can supply additional power drawn from the energy that is mechanically stored in the rotor, is proposed in [Hughes et al., 2005]. The impact of wind turbines and a possible frequency support functionality regarding the Irish power system is discussed in [Lalor et al., 2005].

The feasibility of proportional droop control (used for primary control) in low voltage grids has been investigated in [Engler, 2005] and [d. Brabandere et al., 2007]. In those publications the focus is on local phenomena like harmonics, short circuits, and synchronism to the grid frequency. Stabilisation of the grid frequency via droop control, based on a flywheel energy storage system with converter interface, is described in [Hamsic et al., 2006].

3.3.2 Inertia-less Offshore Cluster Grids

The generation in offshore cluster grids will be mostly variable speed wind turbines. Two different grid connection concepts, which today are applied to large units (5 MW+), seem to be most promising for the future.

- Wind turbines with a doubly fed electric machine (Repower, Bard) have a grid connected electric machine, but the electrical grid frequency and the rotational speed of the rotor are decoupled. The rotor currents are variable in frequency, controlled by power electronics. The power output is not directly related to the grid frequency.
- Wind turbines with a synchronous generator and a fully rated back-to-back converter (Multibrid, Enercon, Siemens, Vaestas) have no direct coupling of the rotating machine to the grid.

The load in offshore cluster grids will be mostly HVDC converters, which transfer the generated electric power to shore.

Neither the generation nor the load contribute in this case to the system inertia, which becomes zero. This removes the operational basis for frequency stability. This even dissolves the functionality of the frequency as a balance indicator.

These facts indicate that balancing of inertia-less AC grids is very challenging. At the moment, there is no consensus on how this could or should be done, and very little literature is available.

The challenges could be addressed by the concept of the virtual synchronous machine (see Section 3.6.1). The application of this method would reconstruct the proven principles of AC balancing control with frequency as balance indicator. It could also be possible to design a completely new operational concept, that uses a different balance indicator.

There are only two facts, that everyone can probably agree on:

- There has to be a system balance indicator.
- The control of power converters has to be designed in such a way that power becomes a function of the system balance indicator.

For wind turbines, this would mean that pitch and rotational speed of the turbine no longer are optimised only with regard to wind speed, but they also become a function of the system balance indicator.

3.4 Frequency Model of the Continental European Power System

A simplified frequency model of the continental European power system has been implemented in MatLab Simulink. Parameters for the system model can be found in [Union for the Co-ordination of Transmission of Electricity, 2009]. The model structure is shown in Figure 3.2.

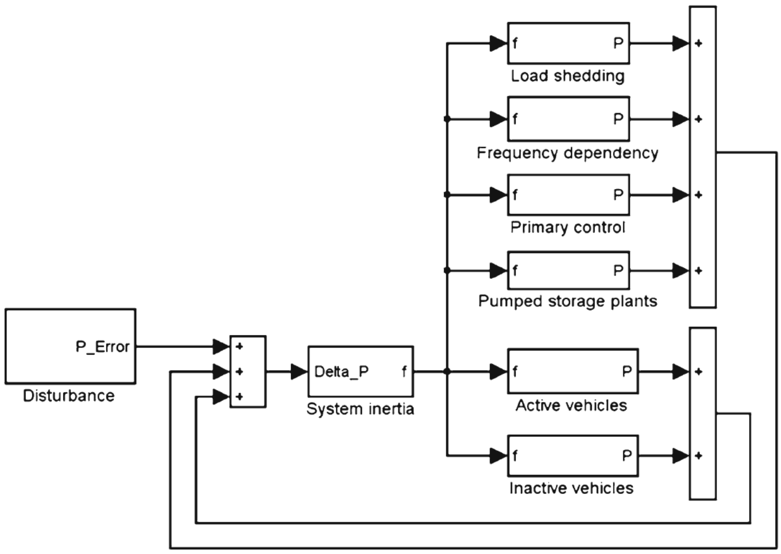

Figure 3.2: Structure of the grid frequency model

The model takes into consideration:

- system inertia
- primary control
- frequency dependency of load
- load shedding

- pump storage power plants

Additional blocks for grid connected devices with frequency dependent power output/consuption can be added to the model, to assess their influence. This can be seen in Figure 3.2 in form of two additional blocks for Plug-in Electric Vehicles (PEV).

The model simplifies the grid to a single node as it neglects its spatial extent. For the simulation of the grid frequency this assumption is valid as grid frequency is a global measure (the frequency is almost the same at any point of the grid). This assumption only causes problems in the first seconds after a large disturbance, which causes frequency oscillations. To compensate for the error created by this assumption, a fuzzy logic approach was used for the implementation of load shedding.

This grid frequency model is simplified, yet it is accurate enough to calculate the effect of power imbalances on the grid frequency. Secondary control is neglected, since it has little influence on the system in the first few seconds after a disturbance. Reactive power is also neglected since it does not directly influence the grid frequency.

The model has been used in Publication VII and Publication IX. The model has also been adapted to represent a two-node system, to show inter-area oscillations between Italy and the rest of continental Europe, in Publication VIII.

3.5 Grid Integration of Photovoltaic Systems

Germany has seen a massive deployment of photovoltaic installations in the last decade, shown in Figure 3.3 [Leuschner]. Since 2009, around 8 000 MW were added yearly to the existing photovoltaic installations.

Photovoltaic systems cause high power peaks around noon. These peaks have exceeded 23 000 MW several times during summer 2013 [EEX] in Germany. The photovoltaic infeed on 2013.07.22 is shown in Figure 3.4.

3.5.1 Standard Grid Connection of Photovoltaic Systems

About 70 % of photovoltaic systems in Germany are connected to the low voltage grid. The power output of solar panels is DC, and grid integration is therefore done via a photovoltaic inverter. These photovoltaic inverters have gained system relevance for the entire continental European power system within only a few years. This is an entirely new development, as generation has not been connected to the low voltage grid on a large scale before.

In the past, low voltage generating units were beyond the focus of transmission system operators. On the other hand, distribution system

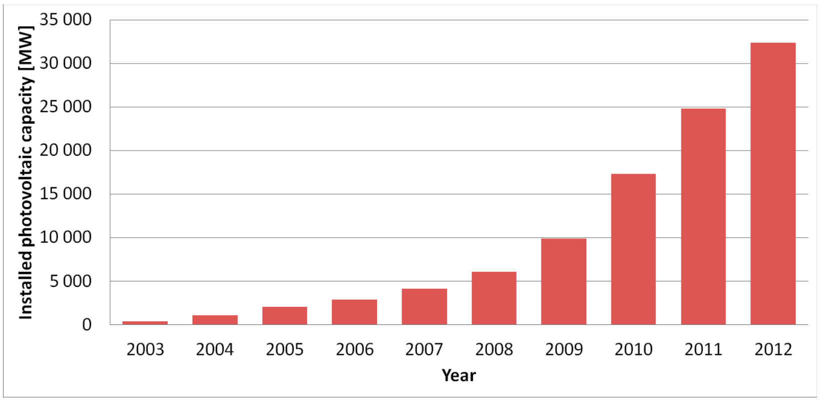

Figure 3.3: Installed capacity of photovoltaic systems in Germany

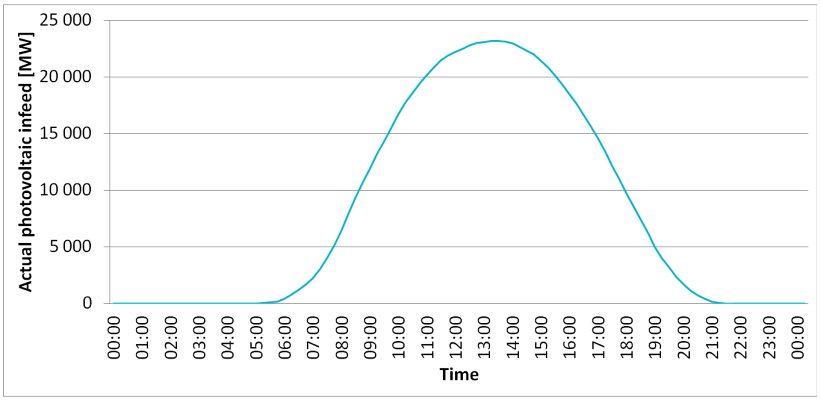

Figure 3.4: Photovoltaic infeed in Germany

operators are not responsible for frequency stability and they concentrated on secure operation, i.e. staff safety with the objective to avoid an unintended islanding.

Deployment of new technology at such a high pace is always a dangerous situation. Some errors in the early designs might only become visible after a few years. This could be at a time, when the 'faulty' design is already in mass production.

This problem has occurred, when a standard for an automatic disconnection device for low voltage generators was defined in Germany [VDE, 2006]. This standard was designed regarding mainly for local phenomena in the nearby low voltage grids and underestimated the importance of large-scale effects. Several other European countries used this standard as well (e.g. France, Belgium, Austria).

The standard demands a disconnection of the photovoltaic system within 0,2 s if $f > 50,2$ Hz. A reconnection is allowed after 30 s if $f < 50,2$ Hz.

3.5.2 Risk of Non-Linear Oscillations

In the case of a severe loss of load disturbance the frequency can rise considerably. Loss of load has happened in 2003 [Vandenberghe et al., 2004] and 2006 [Maas et al., 2007]. The security margin of 0,2 Hz relates to the nominal frequency. The real security margin is reduced to about 0,1 Hz, since about half of the margin can be consumed by the frequency fluctuations mentioned in Section 3.1.

A tripping of a large load (exporting HVDC line such as the Cross-Channel link) could be enough to trigger the disconnection of photovoltaic systems. If many photovoltaic systems detect the over-frequency condition at the same time, the consequences could be severe. A simultaneous loss of a significant share of the photovoltaic generation is a major threat to the safe operation of the continental European power system.

The exact moment when all photovoltaic systems in the continental European power system detect the over-frequency condition depends on the precision of the frequency measurement. This should not have a significant influence, as measurement precision is usually sufficient.

The moment also depends on frequency oscillations in the first seconds after a disturbance. This effect should not have a large impact within a region, as local frequency deviations become more relevant over longer distances. A large share of the photovoltaic installations are concentrated in southern Germany.

Considering the time lag of 0,2 s in combination with a high rate of change of frequency, it is possible that a significant amount of photovoltaic systems will disconnect from the grid simultaneously.

30 s after returning into the allowed frequency range, photovoltaic systems may reconnect and begin to feed in again. This simultaneous increase in infeed will lead to a fast increase of the frequency eventually leading to repeated shut-down / turn-back-on operations. A yo-yo effect could emerge as a general pattern.

3.5.3 Improved Grid Connection Requirements

According to [Berndt et al., 2007] and [Bartels et al., 2008], an active power reduction is demanded with a gradient of 40 %/Hz (droop of 5 %) in the medium voltage grid. A similar approach for the low voltage grid has been proposed in Publication VII.

A working draft has been published [ENTSO-E, 2010], which covers low voltage generators. In this document, a couple of requirements such as the active power frequency response (over-frequency) are proposed, see Figure 3.5. Also [VDE, 2011] has addressed the problems in [VDE, 2006].

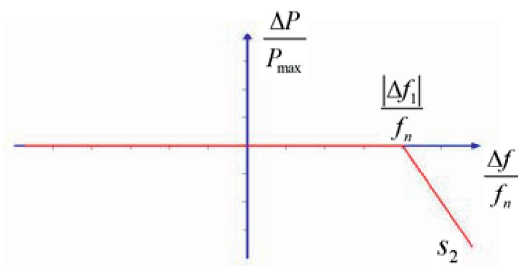

Figure 3.5: Active power frequency response

In the proposed approach, no hysteresis is used when the frequency decreases back to normal after the disturbance. Power is ramped up according to the droop curve. Thus, the frequency is still a clear signal for the load situation of the synchronous zone. As an alterative for switchable units, which are not capable of modulating the power output, randomised switching thresholds should be used.

3.5.4 Validation

To be able to illustrate the non-linear oscillations, the model described in Section 3.4 has been used. The case of a 5 000 MW loss of load has been simulated with 10 000 MW of photovoltaic systems in three variations:

- No frequency response from the photovoltaic systems.
- Response according to [VDE, 2006].
- Response with droop control as proposed in Publication VII.

The simulation plot is shown in Figure 3.6.

The harmful effects on system stability of a simultaneous loss and reconnection of a large amount of photovoltaic systems can clearly be seen. The proposed response from Publication VII showed the best behaviour, but also no response gave sufficient results. The most important reason to run

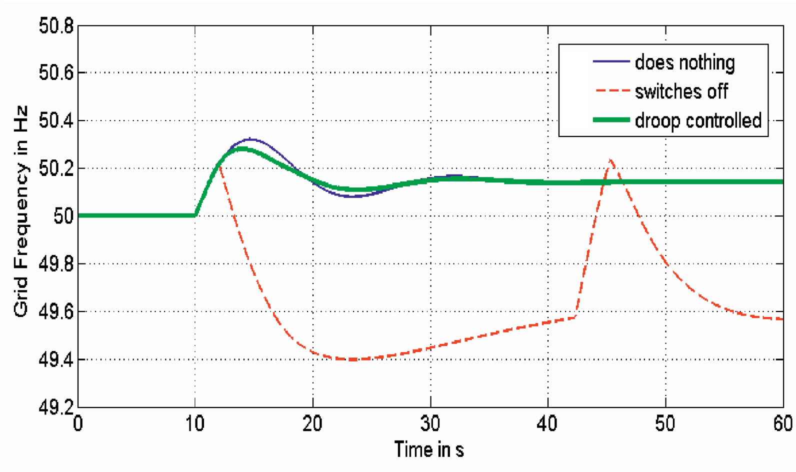

Figure 3.6: Photovoltaic systems influencing the grid frequency

the simulations was to raise awareness about the possible consequences of the frequency response according to [VDE, 2006]. More details are given in Publication VII

The model has also been adapted to represent a two-node system, to show inter-area oscillations between Italy and the rest of continental Europe in the light of non-harmonised national standards. This is treated in Publication VIII.

3.6 A New Control Method for Power Electronic Grid Assets

Modern power electronic converter systems are capable of performing fast control actions, a feature that is not always needed for fulfilling the primary task. As an example, battery charging devices create a DC current and do not necessarily utilise all of their technical possibilities. It could therefore be possible to add special control functions like frequency control support to such devices.

Plug-in Electric Vehicles (PEV) with large batteries are a good example of converter systems which could support frequency control. The grid supporting capabilities of grid connected PEVs are especially important for micro grids [Lopes et al., 2010], which lack regular primary and secondary control. Since the battery charger is a power converter, the electrical behaviour of the PEV is defined by the controller under normal operating conditions. PEVs are used as an example here, but similar principles could also be applied for several other converter systems.

As mentioned earlier, there is a threat to dynamic system stability if classical rotating electric machines are replaced by converter systems with a standard control (where power consumption or infeed is not a function of the grid frequency). But with smart frequency supporting controllers, the frequency stability can benefit significantly from the transition from classical electric machines to assets with a power electronic converter interface.

Therefore a new control algorithm, based on the concept of the virtual synchronous machine, has been developed that includes frequency support. The developed control method is in principle suitable for most kinds of converter systems, and it is not limited to PEVs. This control method is kept simple and general, so it can be adapted to future grid codes. No communication between network operator and PEV is necessary for the basic grid supporting functions. This is opposed to the general trend. Information and communication technologies are often the only focus for smart grid solutions.

Vehicle-to-Grid (V2G) capabilities have been addressed in the literature like [Kramer et al., 2008]. V2G refers to electric power grid services supplied by PEVs. V2G applications like providing secondary balancing power [Kempton and Tomic, 2005] [Guille and Gross, 2008] are compatible with the basic support functionality of this control method.

The new method has been published in Publication IX. This matter has also been treated in Publication X.

3.6.1 The Virtual Synchronous Machine Concept

An electric motor has the self-regulating effect (inertia and frequency dependency), two properties that are very beneficial for frequency stability.

It is possible to imitate the behaviour of an electric machine with a power converter system by implementing a suitable control algorithm. If the emulated electric machine is a synchronous machine, the power converter system behaviour is called a virtual synchronous machines [Beck and Hesse, 2007]. These virtual synchronous machines can operate both as a motor and as generator. The motor mode is in focus here.

Compared to other conventional loads, synchronous motors have advantageous behaviour regarding frequency stability. In fact, a virtual or real synchronous motor behaves like an ideal PD frequency controller. This has been derived in Publication IX.

Virtual synchronous machines even have more advantages compared to real electric machines. Physical properties like the momentum of inertia can be chosen freely and changed easily, by adapting the relevant parameters of the control algorithm. The parameter values can exceed the range which is feasible for actual electric machines and it is possible not only to imitate real machines, but to achieve more beneficial properties than those found in real machines.

Another major advantage is that synchronism cannot be lost. The 'rotational speed' of a virtual synchronous machine is not linked to a rotating mass, and can therefore be adopted to the grid frequency in a very flexible way.

This virtual synchronous machine control concept could help to balance power in systems with a large number of power converters. The developed control strategy is based on the idea of the virtual synchronous motor under normal grid operation conditions.

3.6.2 Control Description

The structure of the control is shown in Figure 3.7.

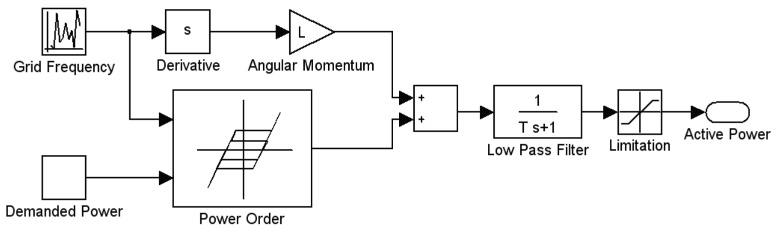

Figure 3.7: Structure of the controller

The power converter is operated at a specific value for the demanded (active) power. This value is set by the operator of the power converter (e.g. owner of the PEV). For the short time frame addressed here, this demanded power can be seen as constant. On a longer time scale, it is of course not constant, but depends on the battery charging strategy. In addition to the basic grid support, V2G applications can be done by influencing the demanded power. However, it is important that any changes in the demanded power occur slowly to avoid interaction with the faster inner control loops.

Based on the demanded power, the steady state power order is calculated, which is a function of the frequency. This represents the proportional part of the control (for small deviations). Based on the frequency gradient, the differential part of the control is calculated and added to determine the ideal power. This ideal power is then low pass filtered to avoid unwanted reactions towards frequency noise. The filtered ideal power is finally limited, if it exceeds the rated power of the converter.

The developed control strategy works for loads, sources and also bidirectional storage units. Battery charging of PEVs has been chosen as example in this thesis and all further explanations will focus on these power electronic loads.

The reactive power of the converter is not regarded here, as it does not directly influence the system frequency. Local AC voltage phenomena are not treated in this thesis.

3.6.2.1 Virtual inertia

The differential part of the frequency control of a virtual synchronous machine is proportional to the angular momentum of the machine, which was chosen as a control parameter. Since the differential control part strongly reacts to high-frequent noise, it is necessary to apply a low pass filter on the control, which was also identified in [Lalor et al., 2005].

The angular momentum should in theory be as large as possible. However, it is limited by frequency noise. A too large angular momentum would also have the disadvantage, that the reaction towards a disturbance would exceed the limitations of the power converter. This problem was identified in [d. Haan and Visscher, 2008].

The choice of the angular momentum depends on the low-pass noise filter chosen. If noise is reduced significantly by that filter, a larger angular momentum can be chosen, but the control will react slower due to that filter. In this thesis, the best compromise was found at an angular momentum of $4\,\mathrm{s}^2$ times the rated power of the converter (with a filter time constant of 6 s). This compromise is based on the simulations with different types of disturbances and noise levels.

This angular momentum relates to a start-up time constant of about 10 minutes, and it is by far larger than the corresponding value of real electric machines (up to 10 seconds). A real synchronous machine with such a large momentum could easily lose synchronism if the frequency changes, but this will not cause problems for virtual synchronous machines.

Low-Pass Noise Filter

To reduce the reaction on the frequency noise, the control output needs to be filtered with a low pass filter. This filter is implemented as a simple first-order low pass to avoid oscillations. Simulation results show that a filter time constant of 6 s is a good compromise between control dynamics and noise resistance. Longer time constants are better suitable for a reduced noise level, but the control will be slowed down.

Since the main advantage of this dispersed converter-based control is the fact that it can react faster than the primary control, a large time constant of the filter is counterproductive. In comparison with real electric machines, 6 s is a large time constant, which indicates that the robustness towards frequency noise of a virtual synchronous machine with the suggested control method would be satisfactory.

3.6.2.2 Frequency Dependency

The power order of the converter, depending on the grid frequency, is shown in Figure 3.8. The different graphs give different demanded power values from maximal battery charging to zero power consumption. Each curve shows the frequency dependent power order of a converter with a specific value for the demanded power, while positive power order represents power consumption.

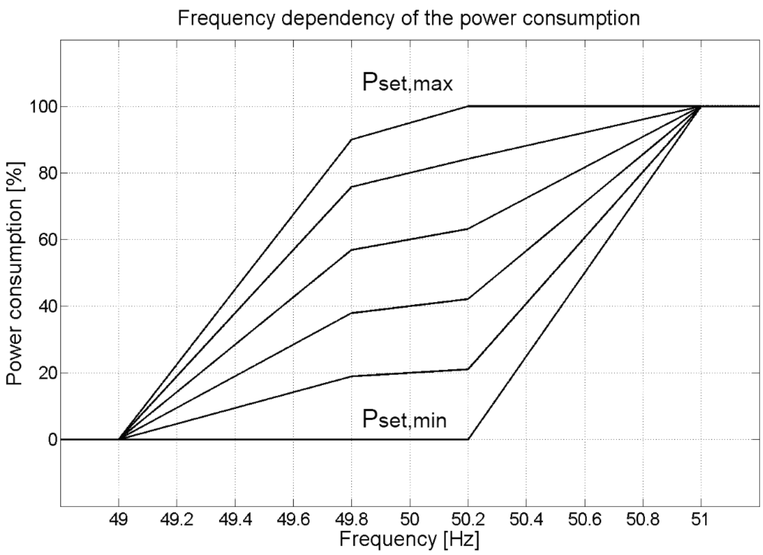

Figure 3.8: Frequency dependent power consumption

The upper curve represents a converter operated at the maximum demanded power of 95 % of its rated power. The lowest curve shows the case of an inactive power converter, so the power order is zero under normal grid operating conditions.

The slope of the curves represents the frequency dependent power variations. These variations are in relation to the demanded power, not to the rated power. The advantage is that a converter with very small power order does not have large deviations (in relation to the demanded power) of the power order. Otherwise operation at low demanded power would be disturbed [Holst et al., 2003]. If the proportional part of the control would be related to the rated power, it could be in the same range as the demanded power (if that is at a low value). In this case, the control power would have significant influence on the primary task of the converter, which cannot be tolerated under normal operating conditions.

The disadvantage is that the frequency supporting effect is depending on the operation point of the converter, and therefore it is less predictable than a fixed supporting effect. However, it is fixed and therefore predictable in relation to the power consumption.

The maximal demanded power has to be limited at normal operation frequency to keep a margin to react towards rising frequency. The maximum value for the frequency dependency is determined by the size of that margin. A margin of 5 % should be tolerable, so the demanded power of the converters is limited to 95 %. This enables the frequency dependency to be 26,3 %/Hz. Regular loads only reach values up to 6 %/Hz (e.g. a fan).

This margin should be feasible, since converters are usually not operated at their absolute limit. Because of the short-term overload capability of converters, it should be possible to implement this control without relevant drawbacks. This of course will need to be verified, to make sure that the frequency support task does not interfere with the primary task of the converter.

If this assumption will be proven wrong, the margin and frequency dependency could be reduced. To achieve a frequency dependency of 6 %/Hz, a margin of only 1,2 % would be needed. The average frequency dependency is assumed to be only 1 %/Hz [Union for the Co-ordination of Transmission of Electricity, 2009], which could be achieved with a margin of 0,2 %.

If the required margin turns out to be problematic, the control method could also still be applied downward, which is more important than upward regulation for loads. This is due to the fact that it is more straightforward to reduce electric power production during under-frequency situations than to increase production during over-frequency situations, which demands maintaining extra reserves at all times.

The control method could also still be applied at times, when the converter operates at lower power than the absolute maximum. Battery loading strategies suggest that this will be the case for a significant part of the loading cycle.

If the frequency dependency would be chosen to be zero, the converter could operate in the dead-band without being under the influence of the grid frequency. Assuming that a large part of the future load will be converter-based, this is problematic. Within the dead-band, the frequency would become more volatile due to the smaller share of load without a dead-band. This is, however, the state of the art of converter controls.

3.6.2.3 Integrated Selective Continuous Load Shedding

As mentioned before, load shedding is the last control action, that can cope with large power shortages in the grid. This important control feature has been integrated into the newly developed control method, and works fully automatically and autonomously (unlike normal load shedding).

The feature is visible in the steep sections of the curves on the left- and right-hand sides in Figure 3.8. This approach offers three significant advantages compared to conventional load shedding: It is selective, dispersed and smooth.

- Selectivity is important, since the shedding of low-priority loads helps to maintain supply for high-priority loads which should not have power interruptions. This has traditionally been hard to achieve, but it is easy to implement for power electronic loads. Every controller can have a tailor-made load shedding scheme, depending on the load priority of the load it controls.

- Smoothness is important to have a good and stable transition from the pre-disturbance state to the post-disturbance state. This has traditionally also been difficult to implement, as load shedding was implemented stepwise as a simple logic control action (on / off). Switching operations like shedding a load always are a disturbance to grid operation. Power electronic loads can reduce power consumption, to any lower value or zero, in a continuous and 'smooth' way.

- Dispersion is important, as it is a means of limiting the negative side effects of load shedding. It is a 'fairer' means of load shedding, as it degrades the power supply to a large region, rather than discontinuing the power supply of a smaller region.

Automatic autonomous dispersed selective continuous load shedding of low-priority power electronic loads can significantly help to prevent more important systems from being shed. This approach can be highly beneficial in case of the unlikely event of a severe system disturbance, but it has not been adequately addressed. It is one of the main advantages of the new control method.

A virtual synchronous machine without this feature would counteract frequency restoration after a massive frequency drop because it would try to stop the rising frequency (due to the differential part), disregarding the under-frequency condition and such a problem occurred in [d. Haan and Visscher, 2008].

3.6.2.4 Non-Load Converter Systems

Feeding Converter Systems

Converter systems, which are not operated as loads but as generation units, also should be frequency dependent.

D-behaviour is easier to implement, as it can be fed from a short-term storage (e.g. inertia of a wind turbine rotor). If the control strategy is applied to power sources, the differential part and the low pass filter remain unchanged.

P-behaviour is however difficult for volatile sources like wind and solar, where long-term power is determined the the maximum power point tracker. If the control strategy is applied to power sources, the proportional part of the control has to be adapted. The reaction towards frequency deviations has to be inverted, to support grid stability. If the frequency drops, consumption should decrease, while generation has to increase. This behaviour of the implemented control deviates from the behaviour of real synchronous generators.

Bidirectional Converter Systems

Bidirectional systems offer the best grid support functionality and PEVs with battery would be perfectly suitable for this. However, the electric power distribution infrastructure was designed for unidirectional use, so bidirectional power converters cannot be used without adaptations to the system. Smart substations or some other kind of control entity would be needed to cope with the power flow reversal.

The recent developments in the smart grid field imply that smart substation could be realised in the near future to make bi-directional V2G applications possible, which would also enable PEVs to connect as bidirectional systems, improving the grid support functions.

3.6.2.5 Inactive converters

An inactive converter is operated at a demanded power of zero. An example for an inactive converter is an PEV, which has been charged to the pre-set level, and therefore does not consume any more power, but which is still connected to the grid.

These inactive converters can activate themselves and supply a service in emergency situations, but they need to remain on standby and observe the grid frequency constantly, to detect these emergency situations. If system conditions are stabilised and grid frequency comes back to the normal operation band, these activated converters can deactivate themselves again, but should do this slowly to avoid a transient caused by the switch-off.

This feature is especially interesting for converters with feeding capability, since they can serve as back-up power sources.

3.6.3 Validation

To be able to evaluate the developed control method, the model described in Section 3.4 has been used.

Two simulations are run simultaneously, one that represents the grid with the regular frequency control mechanisms, and one which also comprises power electronic converter systems, controlled with the developed method. These two simulations make it possible to observe and evaluate the effect of additional dispersed converter-based frequency control.

These converter systems are represented by an active and an inactive PEV fleet:

- Active: The PEVs are connected to the grid and loading their batteries.
- Inactive: The PEVs are connected to the grid but no power is being exchanged (batteries have been charged to demanded level).

The model was used to simulate several kinds of system disturbances considering different quantities of PEVs. A reconstruction of the major disturbance in November 2006 [Maas et al., 2007] serves as an example, since the effects of the control method could be observed in a clear way. During this incident, the continental European power system was split into three zones. This led to outages fur to load shedding in parts of the continental European power system.

The two critical zones that were simulated are western Europe and north-eastern Europe. Western Europe had a large power deficit and north-eastern Europe a large surplus.

The controllers of the PEVs react quickly to the frequency changes due to the differential part of the control, and therefore the frequency deviates much slower. This fast reaction can significantly improve stability, as it gives the primary frequency control more time to activate. Regular load shedding is significantly reduced by the effect of the automatic selective continuous load shedding

The results confirm that the frequency stability can be significantly improved. The details of the simulations are presented in Publication IX.

3.7 Summary

As AC power systems are undergoing changes, balancing control in AC power systems is also undergoing changes. This is mostly due to the large-scale deployment of power electronic systems.

If operated at constant power, power electronic systems (generation and load) do not influence the power balance. This means they neither have a positive nor negative effect. This already can be seen as a disadvantage, since classical loads have a positive influence.

The influence on the grid balance can however be worsened significantly by badly designed control, as it has happened with disconnection devices according to [VDE, 2006], mainly used by photovoltaic systems in Germany. On the other hand, overall system stability can significantly benefit from power electronic systems with 'grid-friendly' control.

A new control method for power electronic systems has been developed, which integrates AC grid frequency support functions. The developed AC frequency control method (Section 3.6) can be seen as a basis for the later developed DC voltage control method (Section 4.5). The basic principle is the same: Proportional control with a control gain increase for large deviations of the input signal. The detailed implementation of that principle is significantly different though.

The activities described in this chapter were discontinued at the end of 2011. This has three main reasons:

- The main focus of this thesis is on the development of the North Sea Super Grid, and on voltage balancing control in HVDC grids. Elaborating details in the research field of this chapter would distract from the main focus.
- The grid stability issues, as explained by Gunnar Kaestle and the author of this thesis have been taken seriously by the VDE and the German transmission system operators. New grid connection standards for low voltage generators have been prepared. The threat resulting from already installed photovoltaic systems will be reduced by a retrofit procedure. Similar risk assessments are now being performed by ENTSO-E on a European level. The main goal, which was to raise awareness for the problems, has been achieved.
- The concepts of virtual inertia, virtual synchronous machines and grid frequency response for power electronic converter systems are relevant for this thesis, to assess similarities and applicabilities regarding HVDC grids. The details of the implementation of those concepts is beyond the scope of this thesis. However, the control methods and the concepts in general that have been developed have gained a broad audience within the scientific community.

If the developed control method would be implemented on a large scale, grid frequency stability would benefit tremendously. Millions of power electronic systems throughout Europe could together supply grid frequency support, which would outperform the existing control mechanisms.

It is however not the manufacturers of power electronic systems, that have responsibility for grid frequency stability. Therefore, they do not have an incentive to implement such a control in their devices.

The solution would be to demand such a 'grid-friendly' behaviour in the grid codes. It would of course not be suitable to define a specific control method in the grid codes, but the general behaviour could be demanded. This would be sufficient to significantly improve grid stability. As new power electronic systems are connected to the grid every day, it is important to adapt the grid codes as soon as possible.

Chapter 4

Balancing Control of DC Power Systems

The balancing of DC power systems is challenging compared to AC power systems. The general challenges of DC power system balancing control and possible control strageties are discussed in this chapter.

The academic community as well as transmission grid operators and manufacturers have gained a strong interest on meshed DC grids [v. Hertem and Ghandhari, 2010]. Improved semiconductors, increased power ratings for AC-DC converters and the first prototypes of DC breakers [Haefner and Jacobson, 2011] have put DC grids within reach. Such a DC grid could be the technical realisation for at least parts of both the North Sea Super Grid (NSSG) and the European Super Grid (ESG). No system of this kind has ever been built, and the entire subject is a future vision and still subject to basic research.

Although many similarities exist, the working principles and operational characteristics of such a DC grid are different from those in AC systems. These main differences result from the fact that no reactive current, reactive power, frequency and phase angle exist. Another important difference results from the system time constants related to balancing, that are shorter compared to AC grids.

Very fast phenomena like switching transients and short circuits are not treated in this thesis. Long-term power flow optimisation is also not part of this thesis. Balancing control in this thesis is understood in the milliseconds to seconds time-scale, similar to primary frequency control in AC systems.

As this chapter is focussing on DC power systems, any physical measures such as voltage and current refer to DC voltage and DC current if not specified otherwise.

This chapter is organised in seven sections:

Section 4.1	The basic operational principles of DC grids are explained, and the general definitions are introduced. Voltage control is argued to be the most suitable means to achieve balancing control, similar to frequency control in AC grids.
Section 4.2	The basic principles of voltage control in DC systems are explained, and the pros and contras of the different approaches are discussed.
Section 4.3	The existing voltage control methods for HVDC converter stations are explained in detail and classified systematically.
Section 4.4	Simplified linear models for HVDC converter stations are introduced, and the limitations of the validity of these models are explained.
Section 4.5	A new voltage control method is introduced which combines the advantages of the earlier mentioned methods.
Section 4.6	The possibilities to integrate converter stations of a HVDC grid into AC grid frequency control are discussed.
Section 4.7	The summary of this chapter.

This chapter is based on Publications XI - XV.

4.1 Balance in DC Power Systems

When balancing DC grids, the first question is:

What exactly has to be balanced?

It is the flows into and out of the DC grid, that have to be in balance. These flows can be expressed either in terms of current or in terms of power. The current balance has significant advantages compared to the power balance, and will therefore be used in this thesis. The balancing control task is to keep the currents entering and leaving the system in balance.

To use the power balance is the state of the art in AC systems it has therefore also been applied to DC systems, like in [Asplund et al., 2012]. However, it is beneficial to refer to a current balance in the DC system rather than a power balance. The reasons for this choice are:

- The current is directly measureable, while it is more complicated to measure power.

- Voltage is directly linked with current for all three standard electric components (resistor, inductor and capacitor). The relation between current and voltage is linear. The relation between power and voltage is non-linear.

- The current balance within a DC system is disturbed by leakage currents. The power balance within a DC system is disturbed by leakage currents and conduction losses. Since these conduction losses are expected to be significantly larger than the leakage losses, the power balance is therefore much more disturbed.

4.1.1 Definition of the Current & Power Reference Direction

In this thesis, positive direction for current and power is defined as flowing out of the DC grid, which is coherent with the physical definitions of voltage, current and power. In power systems, a reverse convention is often in use, which might be more intuitive as production is positive and load is negative. Given the definition on the DC side and the convention on the AC side, an HVDC converter in inverter mode has positive DC current and power. The direction reference is therefore consistently defined for both the AC and the DC sides as shown in Figure 4.1.

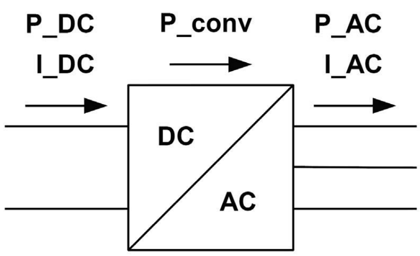

Figure 4.1: Definition of the current & power reference direction

This definition leads to regular AC frequency droop curves having a negative slope, and DC voltage droop curves (e.g. Figure 4.2) having a positive slope.

4.1.2 Balance Indicator

A current imbalance can occur when a grid component (e.g. a HVDC converter station) faces an outage. The missing current from the faulty converter results in an error current. The error current is defined in Equation 4.1, for a DC system with N converters where converter a faces an outage.

$$I_{\text{error}} = -I_a = \sum_{i \neq a}^{N} I_i \tag{4.1}$$

If the failed converter was exporting to the AC system (positive current and power), the outage will cause a current surplus (negative error current). On the contrary, if the converter was importing into the DC grid (negative current and power), the converter outage causes a current deficit (positive error current).

The outage of a converter station will trigger system oscillations. Directly after the disturbance, the consequences will only be visible locally at the node of the faulty converter station, and the disturbance will over time spread through the grid and also affect nodes that are located far away from the faulty converter station.

Whenever an error occurs in the current balance in/out of the DC grid, the error current has to be supplied by capacitive current, to fulfill Kirchhoff's current law. The capacitive current after the outage is identical with the current of the failed converter before the outage. This capacitive current causes the voltage at the different nodes to change as a result of the capacitors and cable capacitance discharging or charging.

To quantify the current voltage relation in a simple way, it is useful to approximate a DC grid with a lumped representation in a single node. This is achieved by neglecting all line inductance and all losses. What remains is the parallel connection of the shunt capacitance of all lines and converter stations (called C_{total}). The voltage at this lumped capacitance is called V_{system}, and it represents the average node voltage.

The system voltage deviation is expressed in Equation 4.2.

$$\Delta V_{\text{system}} = -\frac{1}{C_{\text{total}}} \int_0^t I_{\text{error}} \, \mathrm{d}\tau \tag{4.2}$$

The rate of change of voltage is given by Equation 4.3.

$$\frac{\mathrm{d}V_{\text{system}}}{\mathrm{d}t} = -\frac{I_{\text{error}}}{C_{\text{total}}} \tag{4.3}$$

From Equation 4.2 and Equation 4.3, it can be seen that a current deficit (positive error current) leads to decreasing system voltage and a current surplus (negative error current) leads to increasing system voltage.

The relation between the current balance and the system voltage, as indicated by Equation 4.2 and Equation 4.3 is very important for system balancing, as it enables the utilisation of the voltage as a system balance indicator.

To directly determine the system current balance, it would be necessary to know all currents in and out of the system at all nodes. This is difficult to realise, especially for larger systems.

DC voltage is therefore the balance indicator in a DC power system (similar to AC frequency in AC power systems). Keeping the current in and out of the DC grid in balance is obtained via controlling DC voltage to a fixed value. The DC voltage can be measured locally. However, remote voltage measurements can also be used, as proposed in [Berggren et al., 2010].

Difference between DC and AC Systems

In AC power systems, the system frequency serves as the balance indicator. It is (not regarding transients) a global measure, where the state of the entire system can be determined by local measurement of the frequency. This enables the operation of the primary frequency control, which ensured stable operation of power systems, without communication. Power systems, as we know them today, might not have been possible without the frequency as a global balance indicator.

In addition to frequency, there is the phase angle, which is determining the flows of active power. The phase angle cannot be measured locally, as it needs a reference to be defined. With the introduction of wide area measurement systems, the information which is contained in the phase angle became somehow accessible [Nuqui, 2001]. Measurement procedures are more complicated than for frequency.

In a DC power system, the DC node voltages are the most important measure. The DC voltages differ between the nodes, because DC voltage is not a global measure like AC frequency. Despite this difficulty, the DC voltage still is the best available balance indicator for stable DC grid operation.

The DC node voltages define the system balance *and* the flow on the lines. There is no clear separation of state and flow, as it exists in AC with frequency and phase angle. DC node voltage can easily be measured locally, but the interpretation of the information is more difficult. A change in DC voltage can be caused by a change in the flow, by a change in the balance or a combination of both. There is no possibility to determine the cause of the voltage change with just local measurements. This makes it more challenging for a DC system to have a robust balancing control system that does not rely on communication.

4.1.3 Time Constants

DC power systems do not have the inertia of grid connected rotating electric machines, as AC power systems do. This inertia is to date inevitable in the operation of AC power systems as it can handle short-term imbalances, and it is limiting the rate of change of the balance indicator (grid frequency). This gives the primary frequency control time to react, and a response in the seconds-range is sufficient and has been applied successfully for many decades.

The balance indicator in DC power systems (the DC voltage) can change much faster than the AC frequency in AC power systems, as the rate of change is not limited by the inertia of large rotating electric machines, but by the capacitance of the electric power grid and the connected components. This results in much smaller time constants.

The time constant of a DC system is given by Equation 4.4.

$$T_{\mathrm{DC}} = \frac{V_{\mathrm{system}} * C_{\mathrm{total}}}{I_{\mathrm{total}}} \tag{4.4}$$

which demands the balacing control to be significantly faster, compared to AC system control. This is shown in Example 4.1.

Example 4.1

Calculation with Equation 4.3 for DCS3 from Publication VI with an outage of the ROWPP D1 (1 000 MW):

$V_{\mathrm{system}} \approx 800\,\mathrm{kV}$
$C_{\mathrm{total}} \approx 1,1\,\mathrm{mF}$
$I_{\mathrm{total}} = 4,375\,\mathrm{kA}$ ($P_{\mathrm{total}} = 3\,500\,\mathrm{MW}$)
$I_{\mathrm{error}} = 1,25\,\mathrm{kA}$ ($P_{\mathrm{error}} = 1\,000\,\mathrm{MW}$)

$T_{\mathrm{DCS3}} = V_{\mathrm{system}} * C_{\mathrm{total}}/I_{\mathrm{total}} = 0,201\,\mathrm{s}$
$\frac{\mathrm{d}V_{\mathrm{system}}}{\mathrm{d}t} = -1,136\,\mathrm{kV/ms}$
$\longrightarrow$ 5 % voltage change after $0,035\,\mathrm{s}$

Comparison with classical AC power systems:

$T_{\mathrm{AC}} \approx 15 - 20\,\mathrm{s}$

The values in Example 4.1 are only rough estimates. The transient voltages within the grid will differ from node to node right after an outage. Close to the outage location, the voltage might possibly drop significantly faster than calculated here. But even though this is a simplified calculation, it shows that a regular disturbance of the current balance (e.g. the outage of a WPP) will result in critically low voltages within a short time frame ($0,035\,\mathrm{s}$).

The calculated time constant for the DC system in Example 4.1 is two orders of magnitude smaller than the equivalent time constant of classical AC power systems. A DC system is however about one order of magnitude more robust to voltage changes than an AC power system to frequency changes. Combining these two facts indicates, that a DC system will reach a critical state about one order of magnitude faster than a comparable AC system.

4.2 Basic Voltage Control Principles

As described in the previous subsections, the DC grid is balanced by holding the DC voltage constant, which is done by keeping the currents in and out of the DC grid in balance.

The current balance can be disturbed by a variety of possible causes (e.g. converter outages, line faults). There is also some level of leakage current, which constantly disturbed the balance even under normal operation. An imbalance in the current is supplied by capacitive currents, being supplied from the capacity of the DC grid (mostly line capacitances and converter capacitors). The integral over the current imbalance is proportional to the resulting voltage change. As mentioned in the previous section, the time constant associated with a DC grid are in the ms range, leading to significant voltage changes within a short time.

All methods described in this thesis utilise local DC voltage measurements in order to not fully rely on external data for the control to work. However, the overall performance might be improved by using a common voltage signal for feedback as proposed in [Berggren et al., 2010].

Based on the described behaviour, it is clear that the current balance has to be restored as soon as possible in order to keep the voltage from falling or rising. All control structures discussed further in this thesis rely on the fact that the deviation with the controlled DC voltage (local measurement at each DC bus) is determined and corrected for by the control action, which come down to restoring the current balance.

There are two basic principles how DC voltage can be controlled: Current-based control and power-based control, both are found in [Beerten and Belmans, 2012] and [Wang et al., 2012].

4.2.1 Current-Based Control

In a current-based control scheme, the relationship to be used to control the DC voltage is an I-V characteristic [Prieto-Araujo et al., 2011] [Gomis-Bellmunt et al., 2011]. The main advantage of a current-voltage control characteristic is that it reflects linear control behaviour in the sense that a voltage deviation will result in an equivalent current deviation. As the voltage is linked with charging or discharging the capacitive DC system, the control is linear and is the same for all voltage deviations from any voltage setpoint. As always, the voltage power relation is consequently non-linear (parabolic).

Current-based control can be directly linked with the DC network dynamics: The charging of the capacitances in the DC network relies on a linear current voltage relation, which has the physical unit Ω. This makes current-based control intuitive from a physical perspective as it has the same physical units as the DC line impedance.

Current-based control can be integrated into standard dq-current control schemes [Beerten and Belmans, 2012]. The state of the art for VSC HVDC converter control is dq-current control, indicating the importance of compatibility with that control method.

4.2.2 Power-Based Control

As an alternative to the current-based control, the DC voltage control can be expressed in terms of active power, as discussed in [Hendriks et al., 2007] [Haileselassie et al., 2009] [Beerten et al., 2011]. The power voltage relation is here linear. Contrary to current-based control, power-based control has non-linear (hyperbolic) control behaviour. One should take into account the fact that DC voltage control therefore is non-linear.

Power-based control has the advantage that it is more intuitive from a power system perspective, where the focus often is on transmitted power. It is also somehow similar to power frequency control in AC systems. The power voltage relation would have a physical unit of 1/A or Ω/V, which does not have a direct intuitive physical meaning.

The integration of power-based control into existing dq-current control schemes used in VSC HVDC systems is easier than for current-based control. This is because power is a measure that exists on both sides of the converter, while DC current does not.

4.3 Classification of Voltage Control Methods

Several methods for DC node voltage control have been proposed in the literature, and these methods are gathered and classified in Publication XI. The control objectives and requirements and the steady state working conditions of DC node voltage control are discussed. How these converter voltage control strategies can be combined to grid voltage control strategies is also treated in Publication XI.

The classification of the converter control strategies is of great importance for this chapter. It is therefore included in this thesis and treated in more detail than in the mentioned publication. These converter voltage control strategies are based on the local voltage at the converter DC bus. However, remote voltage measurements can also be used, as proposed in [Berggren et al., 2010].

The approach in this chapter is general and systematic, while the actual control implementation is not covered. Slower control actions, like power rescheduling are not treated in this thesis. Mathematically, this means that no setpoint changes are considered for DC voltage control. The focus is purely on DC voltage control as a means of balancing control, similar to primary frequency control in AC systems.

The voltage control methods are displayed here in form of figures with the characteristic control curve in the *I*-*V* and *P*-*V* plane. All figures are drawn for a load converter, meaning a converter that transfers power from DC to AC (inverter mode). The data chosen for the figures in this section are given in Table 4.1.

These data are given in 'pu', and they do not represent realistic operational data for HVDC stations. They have been chosen for good visualisation of the relevant phenomena which are covered in this section of the thesis.

Table 4.1: Data for control method figures

Parameter	Value
Power limit	1,100 pu
Current limit	1,800 pu
Upper voltage limit	1,240 pu
Lower voltage limit	0,510 pu
Voltage setpoint	0,980 pu
Current setpoint	0,300 pu
Power setpoint	0,294 pu

The figures show the limits for voltage, current and power. These limits are just given in this thesis. A justification can be found in Publication XI.

Examples are given for some control strategies. These examples are concerning the load converter station B3 in DCS3 from Publication VI. The main data for that converter station are summarised in Table 4.2. The examples are not in 'pu'.

Table 4.2: Data for calculation examples

Parameter	Value
P_{nom}	2 400 MW
V_{nom}	800 kV
I_{nom}	3 kA
R_{nom}	$266,667\,\Omega$
P_{set}	1 700 MW
V_{set}	800 kV
I_{set}	$2,125$ kA
R_{equiv}	$376,471\,\Omega$

The equivalent resistance of a converter is calculated with Equation 4.5.

$$R_{\text{equiv}} = \frac{V_{\text{set}}}{I_{\text{set}}} \tag{4.5}$$

For a load converter this equivalent resistance is the size of a resistor that would give the same load as the converter does in the operating point. The equivalent resistance of a feeding converter is negative. The relationship between R_{equiv} and V_{set} and I_{set} is the same as the relationship between R_{nom} and V_{nom} and I_{nom}

4.3.1 Basic Converter Control Strategies

In the previous section, emphasis has been put on how a converter can control the DC voltage and the distinction that can be made, based on the P-V or I-V relationship. In this section, it will be discussed how different control schemes can be approached as a generalised case of a voltage droop control. The discussion holds both for current- and power-based droop control.

The control is complicated by the fact that the voltage in the DC grid varies as a result of the DC grid power flow. In order to obtain a certain power flow, the voltage setpoints have to be different for all converters and should reflect the steady-state power flow solution of the DC network.

The explanation provided in this section reflects the mathematical representation of the control objective in terms of droop characteristics. The actual implementation, however, does not necessarily rely on the proportional droop controller, as discussed below. The term ‘basic strategies’ refers to consistent control strategies, which do not depend on the operating point. The control strategies have only a single parameter, which is the droop value or control gain. The control is therefore linear. The advanced control schemes in Section 4.3.2 can be seen as a combination of the three control types discussed in this section.

4.3.1.1 Droop Control

Voltage droop control (positive droop constant) creates a proportional relationship between the voltage and the control base (current or power). The *I*-*V* diagram for droop control is shown in Figure 4.2, where the main section of current-based droop is a straight line.

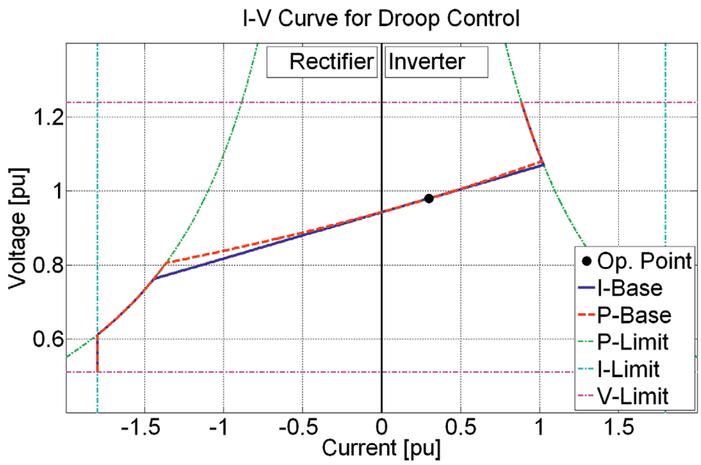

Figure 4.2: *I*-*V* curve for droop control

The *P*-*V* diagram for droop control is shown in Figure 4.3, where the main section of power-based droop is a straight line.

The slope of the *I*-*V* characteristic in Figure 4.2 and *P*-*V* characteristic in Figure 4.3 is determined by the droop constant, which is the inverse of the proportional controller gain used in the actual implementation.

The stability of the droop controller depends on the system to be controlled, the droop value and the actual implementation. If it is well designed, the voltage droop control leads to a stable operation. When a contingency occurs, the droop

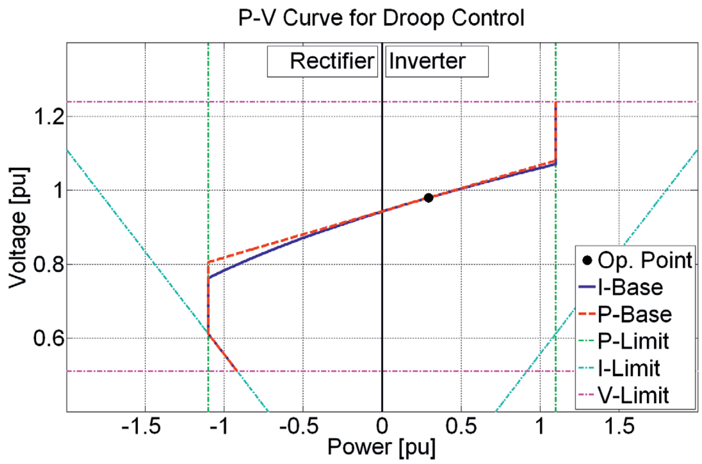

Figure 4.3: P-V curve for droop control

control is characterised by a steady-state deviation from the voltage setpoint as a result of the proportional control action.

The droop constant is called k. The control base is indicated by the subscript 'I' or 'P'. The subscript 'set' indicating the voltage, current and power setpoints, with the natural relationship: $P_{\text{set}} = V_{\text{set}} * I_{\text{set}}$. The voltage, current and power deviations are defined as: $\Delta V = V - V_{\text{set}}$ and $\Delta I = I - I_{\text{set}}$ and $\Delta P = P - P_{\text{set}}$.

4.3.1.1.1 Current-Based Droop Control

The I-V relation for current-based droop control can be written as:

$$\Delta I_I = \frac{1}{k_I} \Delta V \tag{4.6}$$

Rewriting the linear Equation 4.6 in terms of active power yields the corresponding power equation which is parabolic (the details of this derivation are shown in Appendix A):

$$\Delta P_I = \left(\frac{V_{\text{set}}}{k_I} + \frac{P_{\text{set}}}{V_{\text{set}}} \right) \Delta V + \frac{1}{k_I} \Delta V^2 \tag{4.7}$$

At the operating point, an equivalent power-based droop constant for current-based droop control can be derived from Equation 4.7. Due to the non-linearity of power, this equivalent value only holds for small deviation of the voltage.

$$k_{P,\,\text{equiv}} = \frac{1}{\frac{V_\text{set}}{k_I} + I_\text{set}} \tag{4.8}$$

For a feeding converter, the equivalent power droop constant turns negative, when $k_I > -V_\text{set}/I_\text{set}$. This does not appear for a load converter (with positive I_set, where the expression for the equivalent droop constant is always positive.

That means that a feeding converter, with current-based droop control and a high droop value, will decrease the power feed-in when the voltage falls. It is questionable whether it is good to decrease power in-feed when the voltage is falling. But even though a negative equivalent power-based droop constant might not be helping a lot to stabilise the system, it is at least not destabilising it, as it does not appear negative in the current balance.

4.3.1.1.2 Power-Based Droop Control

The expression for the P-V relation for power-based droop control is similar to Equation 4.6, namely:

$$\Delta P_P = \frac{1}{k_P} \Delta V \tag{4.9}$$

Rewriting the linear Equation 4.9 in terms of current yields the corresponding current equation which is hyperbolic (the details of this derivation are shown in Appendix A):

$$\Delta I_P = \left(\frac{1}{k_P} - I_\text{set} \right) \frac{\Delta V}{\Delta V + V_\text{set}} \tag{4.10}$$

At the operating point, an equivalent current-based droop constant for power-based droop control can be derived from Equation 4.10. Due to the non-linearity of power droop control, this equivalent value only holds for small deviation of the voltage.

$$k_{I,\,\text{equiv}} = \frac{V_\text{set}}{\frac{1}{k_P} - I_\text{set}} \tag{4.11}$$

For a load converter, the equivalent current droop constant turns negative, when $k_P > 1/I_\text{set}$. This does not appear for a feeding converter (with negative I_set, where the expression for the equivalent droop constant is always positive).

It is widely agreed that droop control is able to perform well and that it is able to realise a stable system control. It can therefore be concluded, that negative droop control will destabilise the system. A negative current-based droop constant has a destabilising influence on the current balance. This behaviour emulates a negative differential resistance in the operating point, and negative resistance also leads to negative damping.

In other words: when there is a current deficit in the system, the DC voltage is falling as indicated in Equation 4.3. A load converter with a negative equivalent current-based droop constant will react to the voltage change by increasing the load current. This helps to stabilise the power consumption of the load but will at the same time create an even larger current deficit in the system. A voltage change implies a current change in the wrong direction (from a power system perspective).

4.3.1.1.3 Selection of the Droop Constant

The resistance value of a current-based droop constant can be compared with the system parameters to gain a first indication if the droop constant is in the correct range. This is not suitable to fine tune the droop value, but it can give a good first indication in which range the droop value should be. The power-based droop constant does not have a direct physical interpretation and therefore cannot be compared with the system parameters. In the case of power-based droop, the equivalent current-based droop constant (Equation 4.11) can be applied. However, this is a linearisation and not a correct representation, thus the validity of the assessment can be questioned. An example of the selection of the droop constant is given in Example 4.2.

The droop constant should be chosen correctly to ensure small voltage deviation in case of a disturbance of the current balance. $0 \leq k_I << |R_{\text{equiv}}|$ can be used as an indicator that the droop controlled converter has a much stronger stabilising effect on the system than an equivalent resistor would have. A much larger k_I would not be good for voltage stability, leading to large voltage deviations in case of a disturbance of the current balance.

The droop constant should also be chosen correctly to ensure good control cooperation with other droop controlled converters. $k_I >> R_{\text{100km DC Line}}$ can be used as an indicator that after an outage, the new operating point will be mostly determined by all the droop controlled converters and for a smaller part by the influence of the line resistances. A much smaller k_I would not be good for the distributed voltage control of several droop controlled converters, as the line resistances would significantly influence the share of the converters depending on their distance to the fault.

$R_{\text{100km DC Line}} << k_I << |R_{\text{equiv}}|$ can be a first indication of a droop constant which is chosen in the correct range.

Example 4.2

Calculation for the load converter station B3 in DCS3 from Publication VI, based on the data given in Table 4.2.

$k_{\text{pu}} = 0,1$

$R_{\text{100km DC Line}} \approx 1\,\Omega$

Current-based droop control:

$k_I = R_{\text{nom}} * k_{I\text{pu}} = 26,667\,\Omega = 26,667\,\text{kV/kA}$

$R_{\text{100km DC Line}} << k_I << |R_{\text{equiv}}|$ is true.

Power-based droop control:

$k_P = V_{\text{nom}}/P_{\text{nom}} * k_{I\text{pu}} = 0,033\,\text{kA}^{-1} = 0,033\,\Omega/\text{kV} = 0,033\,\text{kV/MW}$

This value cannot directly be compared with the system parameters. The equivalent current-based droop constant can be used as an approximation.

$k_{I,\,\text{equiv}} = \frac{V_{\text{set}}}{\frac{1}{k_P} - I_{\text{set}}} = 29,630\,\Omega$

4.3.1.2 Constant Flow Control

Constant flow control (infinite droop constant) tries to hold the flow of current or power constant. Figure 4.4 shows the characteristic curves for both control bases in the *I*-*V* plane. Constant power control leads to hyperbolic behaviour in the *I*-*V* plane.

Figure 4.5 shows the characteristic curves for both control bases in the *P*-*V* plane. Constant current control leads to a linear behaviour in the *P*-*V* plane. It is therefore linear in current and power.

Constant current control and constant power control can respectively be represented as a vertical line segment in the *I*-*V* and *P*-*V* plane. Mathematically, the constant flow control can be expressed as a limiting case of the aforementioned voltage droop control, with a droop constant equal to infinity, thereby not changing the flow whenever the DC voltage changes. The converter will, at all cost try to maintain the flow constant, irrespective of the value of the DC voltage at its DC bus.

From a system perspective, constant power control is better for feeding converters and constant current control is better for load converters. When assessing the control types without case separation for load and feeding converters, constant current control is better for system stability than constant power control. This is explained in the following two paragraphs and in Example 4.3.

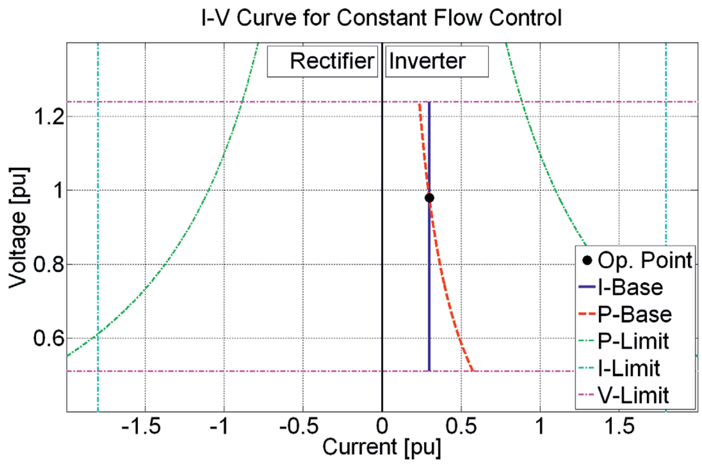

Figure 4.4: *I*-*V* curve for droop control with infinite droop constant

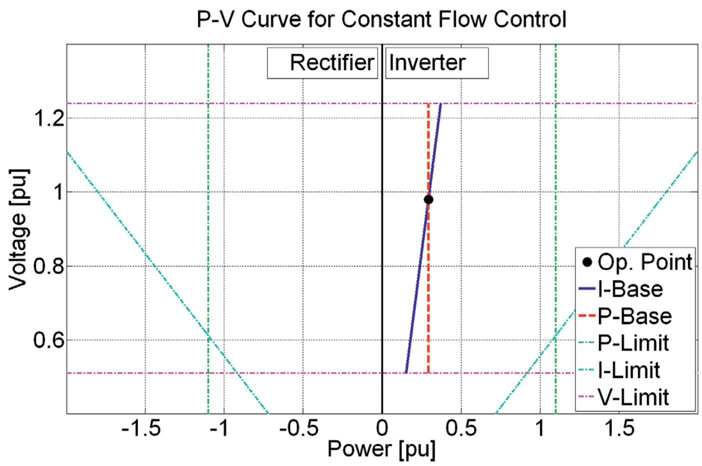

Figure 4.5: *P*-*V* curve for droop control with infinite droop constant

4.3.1.2.1 Constant Current Control

The equivalent power-based droop constant in the limiting case of a infinite current-based droop constant is derived from Equation 4.8 and given in Equation 4.12.

$$k_{P,\,\mathrm{equiv}} = \frac{1}{I_{\mathrm{set}}} \tag{4.12}$$

The equivalent power-based droop constant in this limiting case is not only valid at the operating point (the point of linearisation). It is valid at all times (which is a consequence of constant current control being linear in both current and power). The 'linearisation' of something that already is linear does not introduce any error.

For a load converter $k_{P,\,\mathrm{equiv}}$ is always positive, and there are no problems associated with this case.

A feeding converter with current-based droop control with a high droop constant behaves (at the operating point) like a converter with power-based droop control and a negative droop constant, as explained in Section 4.3.1.1. The limiting case of constant current control leads to the highest (lowest absolute value) negative equivalent power-based droop constant.

To visualise this, a feeding converter with constant current control is shown in Figure 4.6. This figure is identical with Figure 4.5 besides the reversed sign of the current setpoint, which makes the converter a feeding converter.

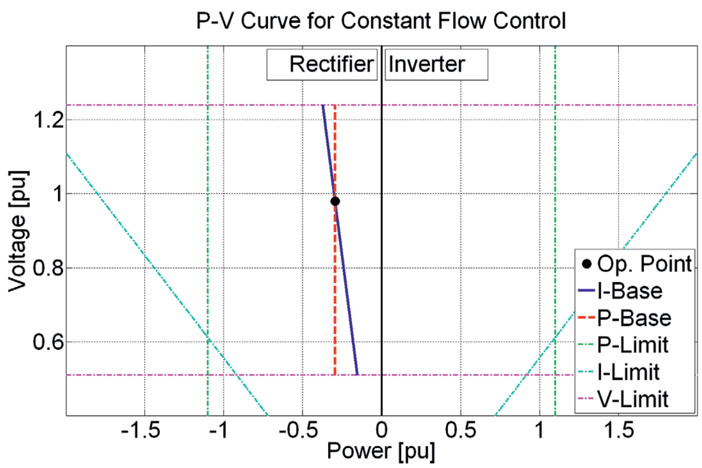

Figure 4.6: P-V curve for droop control with infinite droop constant (feeding)

The negative slope in the P-V plane of constant current control for feeding converters can clearly be observed in Figure 4.6. This negative slope indicates a reduction of the power infeed in case of a system deficit, which intuitively can be seen as counterproductive. However, constant current control does not appear negative (nor positive) in the current balance, as mentioned in Section 4.3.1.1.

Example 4.3

Calculation for the load converter station B3 in DCS3 from Publication VI, based on the data given in Table 4.2.

Constant current control:

$k_{P,\,\mathrm{equiv}} = \frac{1}{I_{\mathrm{set}}} = 0,471\,\mathrm{kA}^{-1} = 0,471\,\Omega/\mathrm{kV} = 0,471\,\mathrm{kV/MW}$

The equivalent power-based droop constant is positive. If the converter was a feeding converter, the equivalent power-based droop constant would have the same absolute value but be negative.

Constant power control:

$k_{I,\,\mathrm{equiv}} = -\frac{V_{\mathrm{set}}}{I_{\mathrm{set}}} = -376,471\,\Omega = -376,471\,\mathrm{kV/kA}$

This means, that if a disturbance in the current balance leads to a voltage drop of 10 kV, the converter would increase its load current by 0,027 kA and therefore disturbing the balance even further. This additional current imbalance is not large for a single converter, but a system with many similar converters could run into problems.

4.3.1.2.2 Constant Power Control

The equivalent current-based droop constant in the limiting case with infinite power-based droop constant is derived from Equation 4.11 and given in Equation 4.13.

$$k_{I,\,\mathrm{equiv}} = -\frac{V_{\mathrm{set}}}{I_{\mathrm{set}}} \tag{4.13}$$

A load converter with power-based droop control with a high droop constant behaves (at the operating point) like a converter with current-based droop control and a negative droop constant, as explained in Section 4.3.1.1. The limiting case of constant power control leads to the highest (lowest absolute value) negative equivalent current-based droop constant, and therefore to the largest negative effects. This behaviour can be see in Figure 4.4.

From a load point of view, it is in most cases desirable to consume constant power. The owner/operator of the load does not usually care about the system voltage and just wants to consume constant power. This makes constant power control appear favourable for load converters, especially for islanded loads like offshore Oil&Gas Platforms (OGPs). Before choosing this control mode, the destabilising effects should be addressed carefully.

For a feeding converter $k_{I,\text{equiv}}$ is always positive, and the mentioned problems do not exist in this case.

4.3.1.3 Constant Voltage Control

Constant voltage control (zero droop constant) can be represented as a horizontal line in the I-V plane, which is shown in Figure 4.7. No distinction between current- and power-based control is shown, since the curves are identical.

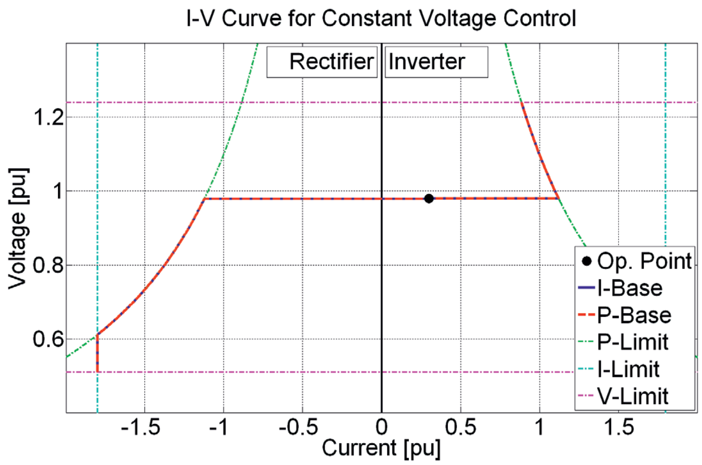

Figure 4.7: I-V curve for droop control with zero droop constant

In the P-V plane, it also appears as a horizontal line, which is shown in Figure 4.8. Also here the curves for power-based control and current-based control are identical.

The control base has no relevance for constant voltage control. The droop constants are zero and the equivalent droop constants are also zero.

DC voltage control can be regarded as the limiting case for which the droop constant goes to zero. From Equation 4.6 and Equation 4.9, it is clear that the converter in this case controls the voltage to its setpoint value. A converter with this type of control is often referred to as a DC slack bus.

This control modus relates to a proportional control gain of infinity. This of course is unrealistic and will lead to instability. Constant voltage control is

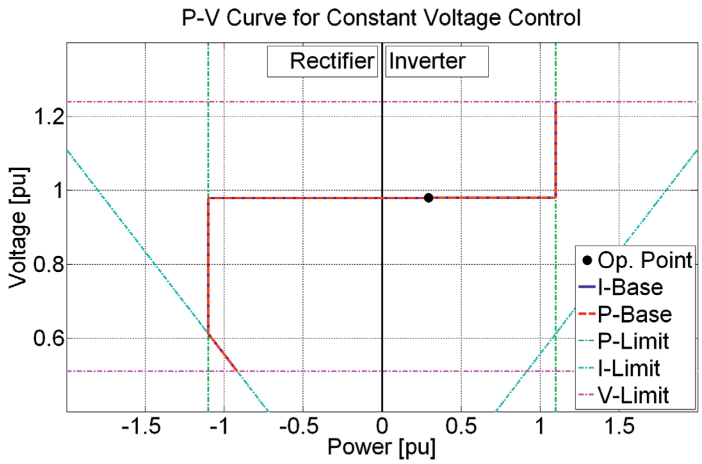

Figure 4.8: P-V curve for droop control with zero droop constant

therefore in reality not realised with an infinite gain, but with a PI controller. In theoretical steady state the outcome is the same, but due to dynamic reasons, the infinite control gain is not viable.

Constant voltage control becomes problematic when two or more converters are connected on the DC side by a very small resistance (connection to the same DC busbar). The constant voltage controllers of these converter might compete with each other, until all but one reach their limits (and therefore give up to force the voltage to their setpoint). It might even lead to poorly damped oscillations.

4.3.2 Advanced Converter Control Strategies

In this section control methods are covered, that cannot be described by a single control parameter. They are therefore non-linear, or to be more precise piecewise-linear. The actual control behaviour depends on the operating point, thereby making a distinction between normal and disturbed operation. The advanced converter control strategies behaviour changes when large disturbances occur.

The general motivation behind these strategies is the fact, that the desired control behaviour is not necessarily the same for normal and disturbed operation.

4.3.2.1 Voltage Margin Control

The I-V curve for voltage margin control is shown in Figure 4.9.

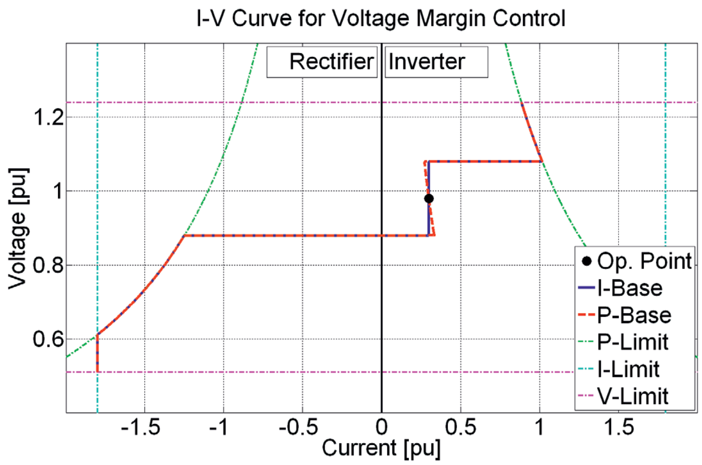

Figure 4.9: I-V curve for voltage margin control

Voltage margin control has first been proposed for DC networks in [Nakajima and Irokawa, 1999] and later been applied and developed further in [Lu and Ooi, 2003] and [Haileselassie et al., 2008]. It is a combination of constant flow control and constant voltage control. A converter with voltage margin control normally operates in constant flow control modus (as long as the voltage is within the normal operation voltage margin). If the voltage deviation reaches the limit of the voltage margin, the converter controller switches to constant voltage control, clamping the voltage at the margin limit to prevent further voltage deviation.

The curve has the same general direction (lower left to upper right corner, positive slope) as droop control. The negative slope in the constant power segment, as described in Section 4.3.1.2, can also be observed here.

The term 'voltage margin control' is used in this thesis as a converter control strategy, according to Publication XI. In Publication XII, it has been interpreted as a grid control strategy, based on the according converter control strategy. This interpretation has been discarded.

4.3.2.2 Dead-Band Droop Control

The I-V curve for dead-band droop control is shown in Figure 4.10.

Droop control can be implemented with an additional dead-band [Dierckxsens et al., 2012]. Just like with voltage margin control, the converter

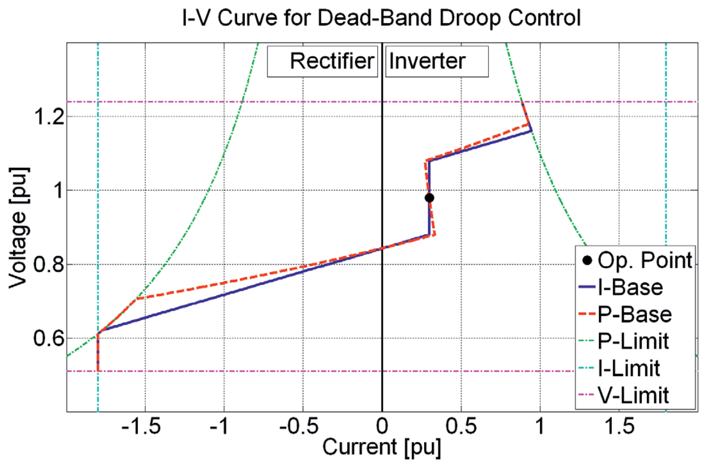

Figure 4.10: I-V curve for dead-band droop control

operates at constant current/power control modus as long as the voltage is within the normal operation band or margin. If the voltage deviates to the limit of the dead-band, the controller switches to droop control. Voltage margin control can be seen as the limiting case of dead-band droop control with a zero droop constant.

4.3.2.3 Alive-Band Droop Control

The I-V curve for alive-band droop control is shown in Figure 4.11.

Another advanced control strategy is constant voltage control with droop control as back-up. This strategy is a useful complement to dead-band droop control. It controls the voltage for small disturbances (where dead-band droop control is not active) and switches to droop control for large disturbances (just like dead-band droop control). As this strategy does not have a name yet, and as it is a complement to dead-band droop control, it has been called alive-band droop control in this thesis.

This control strategy has been described briefly in [Asplund et al., 2012], where it was referred to as droop control with a dead-band in power. This name can be misleading, as the converter control is very active controlling the DC voltage to the setpoint for small disturbances. The control is therefore absolutely not dead within the defined band, and therefore the term dead-band should not be applied here. There is not such a thing as a dead-band in power, as long as voltage is measured and the power is controlled accordingly, like it always is done in a fixed voltage system.

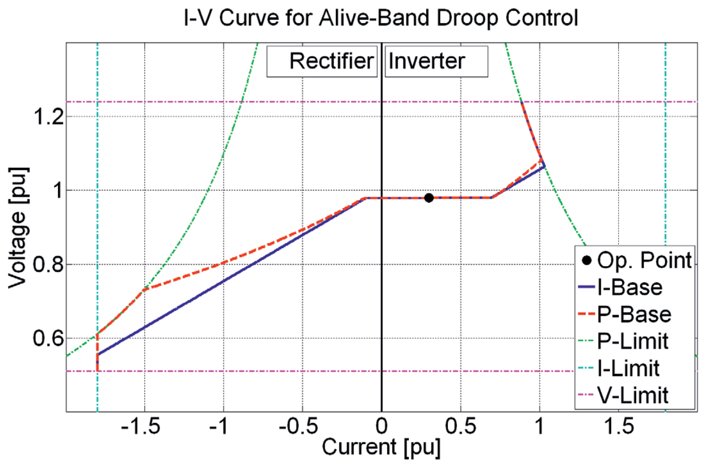

Figure 4.11: *I*-*V* curve for alive-band droop control

4.3.2.4 Autonomous Converter Control

Another advanced control strategy has been proposed in [Barker and Whitehouse, 2010], which they called autonomous converter control. It basically is droop control within a voltage margin. This strategy is shown in Figure 4.12.

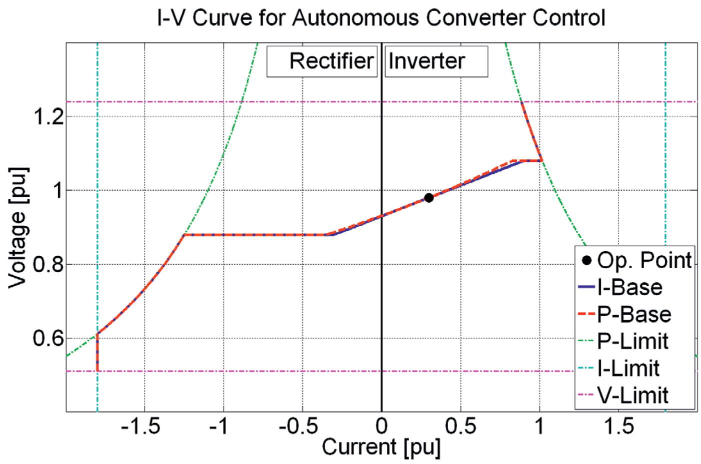

Figure 4.12: *I*-*V* curve for autonomous converter control

4.4 Simplified Linear Converter Models

It is possible to create a simplified linear converter model for the DC side of a HVDC converter station. This can be helpful to reduce the computation effort for the simulation of large systems. Even more relevant is its application for preliminary studies, where easy implementation and adaptation is more important than accuracy.

The simplified linear converter models are well suited for current-based voltage control, since it is linear as well. Power-based voltage control is non-linear (see Section 4.2.2), and therefore any simple linear model can only be applied in linearised conditions for small deviations around the operating point.

The simplified linear converter models can be generally applied for the basic converter control strategies, since these are linear within the entire operation range (besides when reaching the converter limits). The advanced converter control strategies cannot directly be represented by a linear model. For those methods, a linearisation is only valid within one segment of the piecewise linear characteristic curves (e.g. within the dead-band). For creating a linear model for the middle section, where the setpoint is located, the procedure is the same as for the basic converter control strategies.

4.4.1 Current-Based Control

The simplified linear converter models depend on the resistance value of the current-based droop constant.

4.4.1.1 Thevenin Equivalent Voltage Source

If $k_I < |R_{\text{equiv}}|$, the droop controlled converter's behaviour is similar to a voltage source. The converter can be represented by the Thevenin equivalent voltage source model as shown in Figure 4.13.

The droop constant k_I is the inner resistance of the equivalent voltage source. The Thevenin equivalent voltage source is given by Equation 4.14. An example is given in Example 4.4.

$$V_{\text{equiv}} = V_{\text{set}} - k_I * I_{\text{set}} \tag{4.14}$$

For converters with constant voltage control ($k_I = 0 \ll |R_{\text{equiv}}|$), the voltage setpoint and the Thevenin equivalent voltage source become identical $V_{\text{equiv}} = V_{\text{set}}$, as it is given by Equation 4.14. The zero inner resistance is irrelevant, so the model reduces to an ideal voltage source.

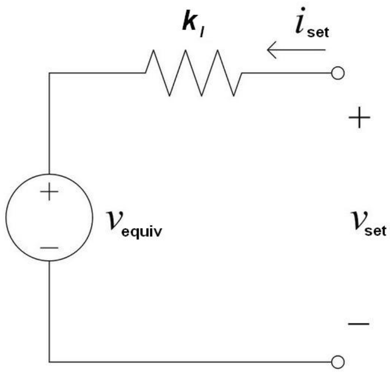

Figure 4.13: Thevenin equivalent voltage source of a converter

Example 4.4

Calculation for the load converter station B3 in DCS3 from Publication VI, based on the data given in Table 4.2.

$k_{\mathrm{pu}} = 0,1$

$k_I = R_{\mathrm{nom}} * k_{\mathrm{pu}} = 26,667\,\Omega$

$k_I < |R_{\mathrm{equiv}}|$ is true.

$V_{\mathrm{equiv}} = V_{\mathrm{set}} - k_I * I_{\mathrm{set}} = 743,333\,\mathrm{kV}$

4.4.1.2 Norton Equivalent Current Source

If $k_I > |R_{\mathrm{equiv}}|$, the droop controlled converter's behaviour is similar to a current source. The converter can be represented by the Norton equivalent current source model as shown in Figure 4.14.

The droop constant k_I is the inner resistance of the equivalent current source. The Norton equivalent current source is given by Equation 4.15.

$$I_{\mathrm{equiv}} = I_{\mathrm{set}} - \frac{V_{\mathrm{set}}}{k_I} \tag{4.15}$$

For converters with constant current control ($k_I = \infty \gg |R_{\mathrm{equiv}}|$), the current setpoint and the Norton equivalent current source become identical $I_{\mathrm{equiv}} = I_{\mathrm{set}}$, as it is given by Equation 4.15. The infinite inner resistance is irrelevant, so the model reduces to an ideal current source.

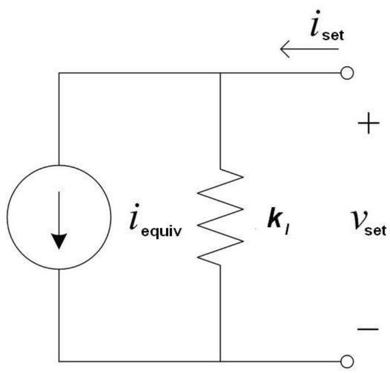

Figure 4.14: Norton equivalent current source of a converter

4.4.1.3 Equivalent Resistor

If $k_I = R_{\text{equiv}}$, the Thevenin and Norton equivalent sources become identical. V_{equiv} and I_{equiv} both become zero, and both equivalent sources reduce to the equivalent resistor.

If $k_I = -R_{\text{equiv}}$ (feeding converter), either the Thevenin or the Norton model can be used.

4.4.2 Power-Based Control

Power-based voltage control is non-linear (see Section 4.2.2), and therefore any simple linear model can only be applied in linearised conditions for small deviations around the operating point. For the implementation of such a linearised model, the equivalent current-based droop constant (Equation 4.11) can be applied. This is a linearisation and not a correct representation, and the validity of the simple linear models can be questioned. An example of the simple linear models is given in Example 4.5.

For feeding converters (R_{equiv} is negative), the condition for the equivalent resistor model $k_{I,\,\text{equiv}} = R_{\text{equiv}}$ could theoretically be possible, because the equivalent current-based droop constant of power-based droop can turn negative. Applying Equation 4.5 and Equation 4.11 yields $k_P = 1/2I_{\text{set}}$. I_{set} is negative for a feeding converter. This shows, that the condition $k_{I,\,\text{equiv}} = R_{\text{equiv}}$ cannot be fulfilled for real values of k_P, which are always positive.

Example 4.5

Calculation for the load converter station B3 in DCS3 from Publication VI, based on the data given in Table 4.2.

$k_{\text{pu}} = 0,1$

$k_P = V_{\text{nom}}/P_{\text{nom}} * k_{\text{pu}} = 0,033\,\text{kV/MW}$

$k_{I,\,\text{equiv}} = \frac{V_{\text{set}}}{\frac{1}{k_P} - I_{\text{set}}} = 28,700\,\Omega$

$V_{\text{equiv}} = V_{\text{set}} - k_{I,\,\text{equiv}} * I_{\text{set}} = 739,013\,\text{kV}$

4.5 Undead-Band Droop Control

All the above mentioned control methods have some disadvantages, that are described in Section 4.5.1. To overcome the disadvantages, a new control method has been proposed for steady-state operation in Publication XII.

The proposed method is based on a so-called ‘undead’-band, meaning that there is a special band around the operating point, but this band is not necessarily dead meaning that there can be (and should be) control action within the band.

The developed control strategy is designed to work for smaller systems that might be built in the near future, but it also can work for any size of HVDC grid, to avoid problems with future system expansions. The method definition is kept wide, leaving the possibility for control parameter optimisation. A validation of the control method on a meshed DC grid has been performed in Publication XIII.

This control method is also defined as a general control framework, and the other existing control methods from Section 4.3 can be seen as specific implementations of the proposed new control method. It can serve as a framework for the control of large DC grids, defining a common standard for the control scheme, but still leave a lot of freedom for individual adjustments, based on manufacturers’ preferences, converter topology, grid strength, etc.

The developed control strategy is mainly based on local measurements. The only external inputs are the setpoints for DC voltage and flow (current or power) which have to be determined by a central DC grid controller, which determines the desired system flow. Based on this desired flow, the central controller determines the voltage and flow setpoints and transmits these to all converters. This procedure is similar when other control methods (Section 4.3) are applied.

An improved version of the control for dynamic operation has been presented in Publication XIV.

The control is referred to as 'active power control' in Publication XII, Publication XIII and Publication XIV. This is however slightly misleading and outdated. First of all, it is not really active power control, but it is active power based DC voltage control. The control base has later been changed to DC current instead of active power (see Section 4.2).

4.5.1 Motivation

Since no large meshed DC grid has ever been built, the focus of the existing control strategies has traditionally often been on smaller DC systems that exist or might exist in the near future. These control methods therefore have some disadvantages when it comes to large DC grids. These disadvantages are treated in Publication XI, and also in Publication XII.

The basic control methods from Section 4.3.1 are very simple, which is an advantage but also a disadvantage. The control methods are described by a single parameter, the droop constant, and therefore behave identical for all disturbances. In a real grid operation situation, there are different kinds of disturbances (wind fluctuation, converter outage, etc.). A differentiated control response can be desirable. In other words, the controller should distinguish between normal and disturbed operation.

As an example, for a load converter supplying power to compressors on an offshore OGP, it could be desirable to operate at constant power and to disregard small voltage fluctuations around the operating point, to keep the rotational speed constant under normal operating conditions. But if there is a severe outage in the DC system and a significant voltage drop, it could be desirable that the converter supports grid stability by reducing consumption. This becomes especially important when a blackout can be prevented by doing so, where the load converter can avoid a discontinuation of its own power supply by being 'supportive'.

To introduce a possibility to have separate control behaviour under normal and disturbed conditions, the advanced control methods from Section 4.3.2 have been introduced. These have the common feature, that the characteristic curve is not a straight line but it consists of three straight segments, where the middle segment is around the operating point and the other two segments are on both sides. The two outer segments for disturbed operation have the same droop constant, which is different from the droop constant in the middle segment for normal operation.

These advanced strategies have the disadvantage, that some of the parameters are set to zero and infinity, which again gives no freedom for parameter tuning. There is no good reason to fix these parameters to zero or infinity, prior to the parameter tuning process. Zero and infinity are however valid possible outcomes of the tuning process.

To address these disadvantages, the new undead-band droop control strategy has been developed.

The autonomous converter control concept, as described in [Barker and Whitehouse, 2010], has later been modified in [Barker and Whitehouse, 2012a]. This modified version is very similar to undead-band droop control.

Also another large manufacturer of HVDC converters mentioned informally, that a similar concept is being considered. However, there are no official statements or publications available.

4.5.2 Control Description

A new control method called undead-band droop control has been proposed in Publication XII. The control is fully based on voltage droop, but distinguishes between normal and disturbed operation by defining different droop constants for these two operation regimes. It offers the possibility to optimise the droop constants and the overall control separately for normal and disturbed operation. This I-V curve is shown in Figure 4.15.

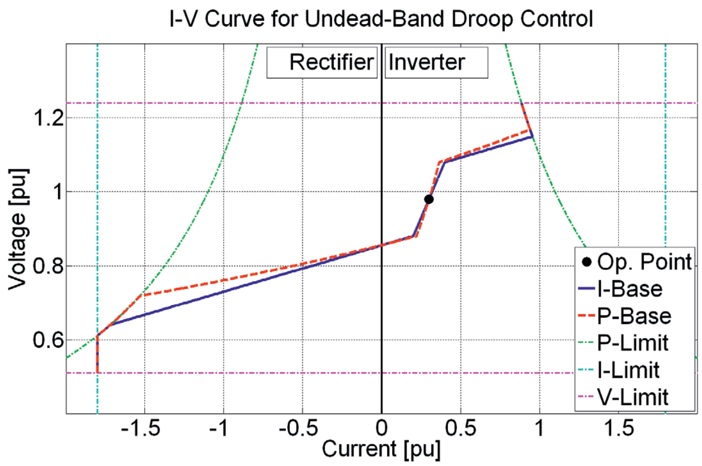

Figure 4.15: I-V curve for undead-band droop control

There are two separate droop values, for the two types of operating conditions (k_1 for normal and k_2 for disturbed operation).

Undead-band droop control is a general concept and holds for both current- and power-based control. But still, current-based control has advantages compared to power-based control (Section 4.2, Section 4.3.1.1 and Section 4.3.1.2), and is recommended as the control base for undead-band droop control.

During normal operation the system is controlled, using the k_1 parameter. This is similar to normal droop control, but the droop constant can be chosen more freely, since it is only being applied under normal operation.

For regular droop control, the droop constant has to be selected in a way so that it can also handle large disturbances. The ‘optimal’ droop constant might not be the same for normal operation and disturbed operation, and while regular droop control needs to find a compromise, the k_1 value can fully be optimised for normal operation. This is especially important if small and weak AC islands (like ROWPPs) are to be relieved from the burden of system balancing under normal operating conditions.

Regarding large disturbances, droop, dead-band droop and undead-band droop control behave similarly. All converters take their share in compensating the disturbance via their droop constant (k_2 for undead-band droop control). These shares, as well as the bands out of which k_2 is active, do not necessarily need to be equal, but can depend on the converter rating and the strength of the connected AC bus. The k_2 parameter can be optimised specifically for disturbed operation, as it is with dead-band droop control.

For undead-band droop control, all parameters can be optimised freely. As mentioned in Section 4.5.2.1, any of the other control methods could be the result of the optimisation process. Still, the desired differentiation between normal and disturbed operation and general concerns about control parameters being zero or infinity should in many instances lead to a different outcome.

4.5.2.1 Inclusion of Other Control Methods

An interesting feature of the developed control method is that all the other mentioned control methods can in fact be considered as specific implementations of parameter sets of undead-band droop control. This is shown in Table 4.3.

Table 4.3: Undead-band droop control parameters of other control methods

Control method	Normal	Disturbed
Undead-band droop control	k_1	k_2
Droop control	k	k
Constant voltage control	0	0
Constant flow control	∞	∞
Voltage margin control	∞	0
Dead-band droop control	∞	k
Alive-band droop control	0	k
Autonomous converter control	k	0

For example, dead-band droop control can be seen as the limiting case of undead-band droop control with an infinite k_1 (constant flow). Similarly, voltage margin control can be seen as the limiting case of undead-band droop control with an infinite k_1 (constant flow) and a zero k_2 (constant voltage). Regular droop control can be seen as the limiting case of undead-band droop control with $k_1 = k_2$. Also other strategies, not mentioned in this thesis, could be perceived accordingly.

A table similar to Table 4.3 can also be found in Publication XII. That table however does not refer to converter control strategies, but to grid control concepts that are based on these converter control strategies. To avoid confusion, it is recommended to focus on Table 4.3.

4.5.2.2 Comparison with Other Control Methods

From all the mentioned control methods, droop control and voltage margin control can be seen as the two most extreme cases. Undead-band droop control can be seen as a compromise between those two methods. This is shown in Figure 4.16.

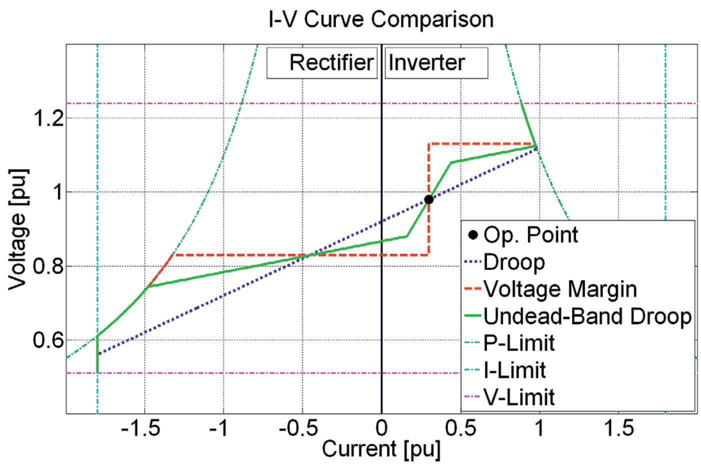

Figure 4.16: Comparison of control methods

Droop control is linear and it controls neither the voltage or nor the flow directly. It is perfectly suitable for distributed DC voltage control. It gives rather ‘fuzzy’ operating conditions as neither voltage nor flow is fixed at a specific value.

Voltage margin control is the most non-linear and it always directly controls either voltage or flow. It does not allow distributed DC voltage control, as the controller either controls voltage without regarding other converters or it ignores the voltage and controls the flow instead. It gives very exact operating conditions, as either voltage or flow are at a fixed and known value.

Both methods have some good reasons to be designed the way they are, but they can be seen as complements to each other. The advantages of droop control gain significant importance with increasing size of the power system.

Undead-band droop control can be seen as a compromise, combining the properties of the two mentioned methods together. It can be fine-tuned for each specific application depending on the importance of distributed control properties and the importance of the exact maintenance of the specific operating point.

With undead-band droop control, the selection of the control method no longer is a 'black-or-white' decision, but it allows for all shades of 'grey'.

4.5.3 Dynamic Control

The undead-band droop control, using a stepwise linear droop curve with different droop values, as published in Publication XII, has been designed for steady state operation. The dynamic performance of that control was not very good, because dynamic issues had not been addressed in the first instance. Therefore the control method has been revised and improved for dynamic performance (Publication XIV). Both non-linearities at the junctions of two linear parts and dynamic instability due to high control gains have been treated and a new improved control structure has been proposed.

4.5.3.1 Smooth Droop Curves

The droop curves with undead-band as in Figure 4.15 have sharp edges at the border between normal and disturbed conditions, where the controller switches over from one gain value to another gain value. At this point the controller behaves very non-linearly, which has disadvantages and may cause and/or worsen undesired oscillations.

To mitigate these disadvantages, the droop curves are smoothened with a moving average filter. Therefore the control gain will change progressively from one value to another, when the error exceeds the defined undead-band, rather than jumping to the new value. This of course can neither remove the non-linearity, nor should it. as the non-linearity actually is desired. Smoothing makes linear approximation possible at any point on the curve (not possible for unfiltered curves with sharp edges). The moment when the limit of the undead-band is reached does not cause a step change in the control behaviour. The smooth control characteristic, which reduces the non-linearity at the borders of the undead-band, is shown in Figure 4.17.

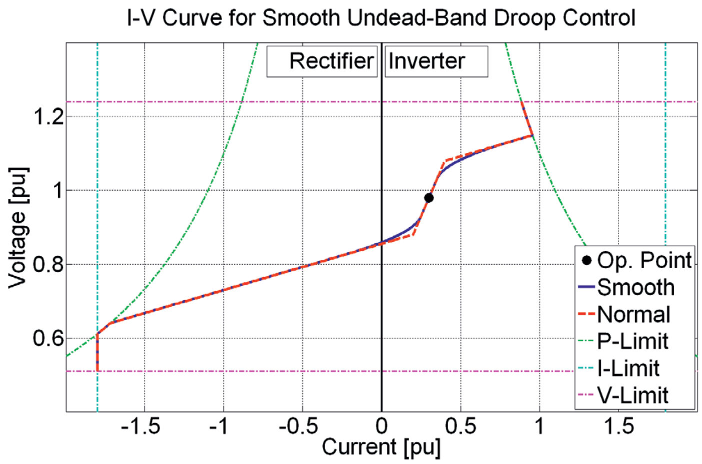

Figure 4.17: I-V curve for smooth undead-band droop control

The width of the moving average filter window should be around 25 % of the undead-band. This has been identified as a good compromise between the conflicting goals of good smoothening (large window) and linear behaviour around the setpoint at small voltage deviations (small window). The filter window applied to Figure 4.17 has been a bit larger for better graphic illustration.

Filtering is always done with regard to the control input (voltage). The filtered curve looks rather unusual, because the control input is on the y-axis. This is due to the strange convention for plotting droop characteristic curves, with x-axis and y-axis switched. Normally, the input of a function is on the x-axis.

4.5.3.2 Separate Dynamic Control Curves

If the DC voltage is to be controlled without larger deviations, high control gains are necessary for the controllers. Even though a high gain will give the desired result in steady state, it might lead to dynamic instability and oscillations. This problem has been addressed by introducing separate characteristic curves for steady-state and for dynamic operation. These curves have a similar nature, as shown in Figure 4.15 and smoothened like in Figure 4.17, but have different control gains. The dynamic control gains have to be limited to values that do not endanger stability, but the static control gains can be higher.

The two different characteristic curves are applied to two parallel controllers. Both controllers receive the measured DC voltage deviation as an input signal, and give the resulting control action as an output signal. These output signals are filtered: For the dynamic controller with a high pass filter and for the static controller with a low pass filter. These two filtered output signals are finally added.

By applying the same time constant to both filters a smooth fade-over from dynamic control to static control can be achieved. The filter time constant has to be chosen considering the resonance frequencies of the oscillations that are to be avoided. For the simulations a time constant of 50 ms has been applied. The complete control block diagram is shown in Figure 4.18.

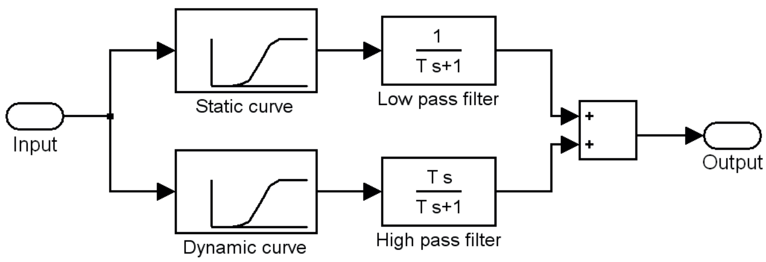

Figure 4.18: Block diagram of improved undead-band droop control

For undead-band droop control, the control gain becomes a function of both DC voltage deviation and time. The controller output (change of the DC current) is the product of the control gain and the voltage deviation. The relationship between control output, DC voltage deviation and time is shown in Figure 4.19.

The smoothening effect of the moving average filter can be observed. Also clearly visible is the gain increase over time from the dynamic value to the static value. This applies only outside the undead-band (in this specific figure), where the normal operation gain is low, and no separate dynamic gain is needed for normal operation. If a high gain for normal operation is chosen, a separate dynamic gain might be needed there as well.

4.5.4 Validation

The proposed control method has been implemented and tested in the power system simulation tool DIgSILENT Power Factory, in order to achieve validation of the control principles and functionality of the undead-band droop controller. The characteristic curves for the different control strategies have been created in MatLab and imported into Power Factory as look-up tables.

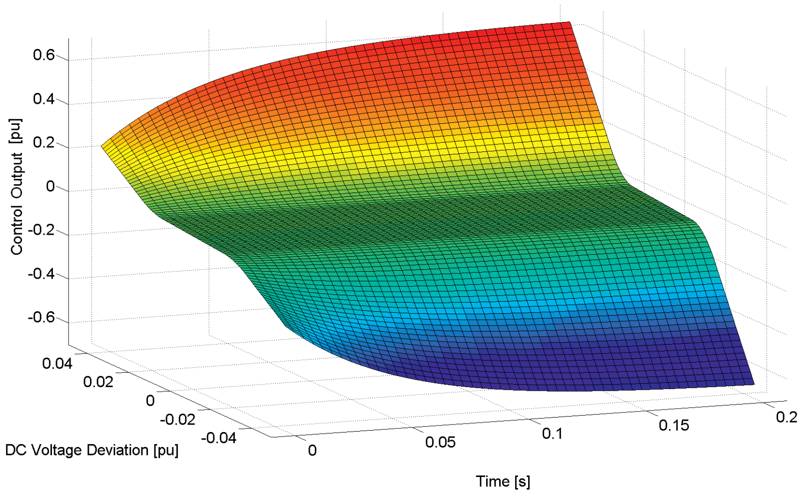

Figure 4.19: Control output as a function of DC voltage deviation and time

A first Validation of the new control method has been performed on a simple three-terminal DC system. This validation has been published in Publication XII.

To get a more realistic view of the control behaviour, a large DC grid test system has been designed and implemented. This is documented in Publication VI. The control method has been realised for this DC grid test system, and the results are given in Publication XIII. The improved dynamic undead-band droop control has also been validated with that test system in Publication XIV.

4.5.4.1 Simple Test System

The undead-band droop control has been inserted into the simple three-terminal model for control validation. The steady-state behaviour of the system was working well as expected, demonstrating the validity of the approach. The details of this validation can be found in Publication XII.

The three-terminal model used in the validation has been developed during a workshop at DTU Wind Energy in December 2011 in the OffshoreDC Nordic project. In order to achieve a realistic scenario, a possible connection between Germany and England with a third terminal in the Netherlands was represented, utilising two AC grids and three HVDC converters. The basic model is freely usable and distributable under the GNU General Public License and is available at [Offshore DC Project].

The grid layout that has been used in this work is the same as in the original model, while its control has been modified in order to perform the described undead-band droop control.

The three HVDC converters are controlled with three different concepts. One converter is operating with droop control, one converter with constant power control and one converter with undead-band droop control.

The simulation case included two power setpoint changes of the converter with constant power control. It has been observed how the other two converters act, based on their control strategy, in order to accommodate the caused imbalance.

4.5.4.2 Full Test System

The next step in the demonstration of the validity of the approach was the application in a larger network, including nodes with different nature. Hence, the undead-band droop control has been applied to a larger network, demonstrating its efficiency in systems with more relevant size and illustrating how the strategy can be easily adapted to nodes with different characteristics. The details of this validation can be found in Publication XIII.

The system used was the CIGRE B4 DC grid test system. This system in its final version is described in Publication VI, but as it was not yet finalised when the simulations were carried out, a preliminary version of that system has been used for the validation study. The differences between the two versions of the test system were assessed as not having any significant impact on the validation study. Some information on that earlier version of the test system can be found in Publication XIII.

The undead-band droop controller has been inserted for all four onshore HVDC converters in the test system. All converters are given different control parameters to display the flexibility of the undead-band droop control approach. The four implementations of undead-band droop control are:

- Droop control with high droop value.
- Droop control with low droop value.
- Constant power control.
- 'Real' undead-band droop control, with high droop value for normal operation and low droop value for disturbed operation.

These four completely different types of control behaviour of the four converters could be achieved without making any changes to the control blocks of the undead-band droop controller. It is only the control parameters that differ between the converters.

The simulated case is at first a loss of load (100 MW) and later a loss of generation (1 000 MW). This is a significant disturbance, since 25 % of the total generation of the DC system is lost. As expected, the loss of load causes the voltage to rise and the loss of generation causes a voltage drop.

The voltage profile of the network is changed after the severe disturbance, due to a changed power flow. This is of course a result of the different control strategies of the four converters.

The converter with low droop value absorbs most of the first disturbance, but reaches its limitation during the second heavier disturbance. The consequence is that the voltage drops outside the undead-band. This leads to the undead-band droop controlled converter switching from the normal operation droop value to the disturbed operation droop value. This significantly increases its control contribution, which stops the voltage from falling even further.

For validation of the dynamic improvements of undead-band droop control, a loss of generation scenario has been simulated in Publication XIV. There it can be observed, that oscillations could be avoided with the application of the dynamic controller.

4.6 Primary Frequency Control Support through HVDC Grids

In classical AC power systems, the power is supplied by conventional power stations. These contribute to primary frequency control and enable stable and secure operation of the system.

In a future AC power system, a large share of the power could be supplied from a offshore HVDC grid, or to be more precise from the HVDC converter stations. Primary frequency control might become challenging as there will not be as many conventional power stations.

The most obvious solution to this problem would be to implement the HVDC converters in a way that they do not only replace conventional power stations as a means of a power source, but also as a source for regulating power. In other words, the HVDC converter would need to take part in primary frequency control [Haileselassie and Uhlen, 2010].

4.6.1 AC Frequency Droop Control

Primary frequency control is implemented in a distributed way, where many power stations contribute with power-based frequency droop control. An HVDC converter station could do the same, but this is conflicting with other control tasks of that converter station. For both constant DC voltage control and constant flow control, the output of the converter is determined, and cannot be a function of the AC frequency. This problem does not occur for DC voltage droop control. Here, the converter output becomes a function of both AC frequency and DC voltage (the two balance indicators on both sides). A possible control approach, based on droop control, to achieve this has been presented in Publication XV.

The proposed control strategy implements droop control for the DC voltage and for the AC frequency at the same time. This links the balances of the AC and DC sides together. A balance deviation on one side leads to a corrective control action. This control action is experienced on the other side as a balance deviation.

This way, the imbalance on one side is turned into a shared imbalance on both sides of the converter. The disadvantage is, that both sides of a converter are affected by a disturbance on one side. The advantage is, that the consequences of an outage are distributed on a larger area, leading to a less severe impact.

The control base applied for AC frequency droop control is power. The application of the DC current would not make sense here, as DC current is not a relevant measure on the AC side.

A significant advantage of the strategy is the fact that if several asynchronous AC power systems are connected to the same DC grid (three AC areas around the North Sea), the proposed control strategy automatically exchanges primary reserves between the AC systems. If the DC system contains energy storage, it is also automatically activated.

4.6.2 Undead-Band AC Frequency Droop Control

The same control concepts with undead-band droop control, which have been introduced for DC voltage control can also be applied for AC frequency support. This is given in Publication XII.

The combined DC voltage and AC frequency control characteristic is shown in Figure 4.20. When reading the figure the three parameters on the three axes should be observed carefully, giving the figure a different appearance than regular droop curves. For simplicity and clearer graphic illustration, power has been used as a control base in this figure for both DC voltage and AC frequency.

The central square-shaped area with small slope is the normal operation area. The steeper band-shaped areas indicate disturbed operation. The remaining very steep areas apply when both voltage and frequency are outside the tolerance. The completely flat areas at the top and bottom indicate the power limitation of the converters.

Also for AC frequency control a distinction between normal and disturbed operation is desirable. Load shedding is a good example of an AC frequency

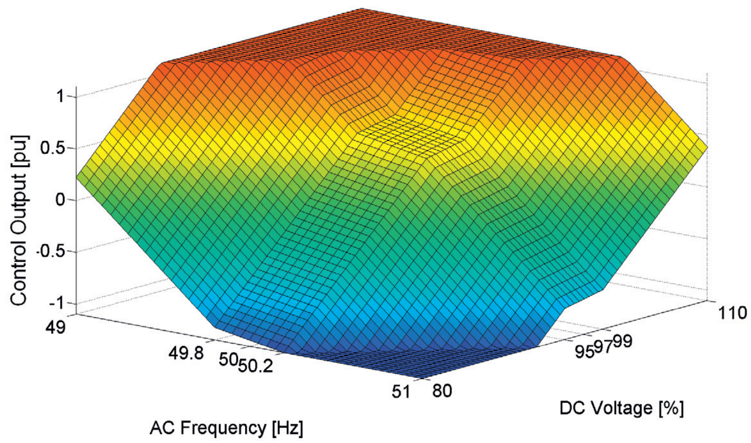

Figure 4.20: Control output as a function of DC voltage and AC frequency

support mechanism that is not active at all during normal operation, and which is the main mechanism under heavily disturbed operation (power shortage).

The desirable case separation for small and large disturbances of the frequency can be achieved with undead-band AC frequency droop control. The application is even easier than for DC voltage droop, since AC frequency is a global measure, the frequency setpoint for all converters is equal to 1 pu (50 Hz). As an example, the normal frequency band could be set to a margin of $0,4\,\%$ ($0,2$ Hz).

The resulting undead-band AC frequency droop curves in the P-f plane look similar to undead-band DC voltage droop curves in the P-V plane. The main difference is the negative slope of frequency droop curves compared to the positive slope of DC voltage droop curves, as mentioned in Section 4.1.1.

4.7 Summary

HVDC systems were until now always limited in size (few nodes) and therefore complexity and could therefore be treated and controlled in a deterministic way. AC systems like the interconnected continental European power system can have a very large number of nodes and have therefore to be treated and controlled differently.

Many challenges have to be addressed to make HVDC grids feasible. Several of these challenges are based on the fact that operational principles, known from AC systems,often cannot be directly applied to DC systems but they need to be adopted, modified or even redesigned. One of these challenges, balancing control, has received special attention in this thesis.

The balance in a DC system should not be considered as a power balance (as it is done in AC systems) but as a current balance. This is a major advantage of DC systems, based on the fact that there is no reactive current and power flow in DC. All current is ‘active’ current, and the balance of the system is a balance of the current in and out of the system. Actually it comes down to the number of electrons being stable.

The best balance indicator in a DC system is the DC voltage. This is due to the capacitive character of such a system and the linear relationship of voltage and current in a capacitor. Controlling the voltage within a narrow band is an effective method for balancing the flows in and out of a DC grid. Voltage control has to be quick, as the capacitance of the system can only cope with imbalances for a short time.

The best and most natural way to influence the DC voltage and therefore the DC current balance with control is to use DC current as a control base. This is breaking with the state-of-the-art control concepts for HVDC converter stations which are based on active and reactive power and not on DC current.

Several methods have been proposed for voltage control. A balancing controller with linear relationship between voltage and current is droop control. Constant voltage control and constant flow control (current or power) can be seen as limiting cases of droop control. More advanced control strategies like voltage margin control or dead-band droop control are piecewise linear and can be seen as case sensitive droop controllers.

A new strategy called undead-band droop control has been proposed, which is a general piecewise linear controller. The other mentioned control methods can be seen as specific implementations of undead-band droop control. Its definition is general and flexible, and it can therefore unify the voltage control methods, and serve as a general framework for voltage control.

The specific realisation of undead-band droop control as shown in Figure 4.17 has a low gain (high droop constant) for normal operation and a high gain (low droop constant) for disturbed operation, and can be compared to the other control methods.

The normal operation gain can be chosen to find a compromise between well-defined operation of the converter (smaller gain, voltage margin control) and grid stability support (higher gain, droop control). If zero gains (and especially negative equivalent gains as for constant power loads) are avoided, stable grid operation can be achieved, where all converters cooperate to maintain the system balance.

Low droop values can significantly contribute to the ability of a system to handle large disturbances. Low droop values are generally better for the entire system, while high droop values are better for the individual converters. Instead of finding a compromise, undead-band droop control gives the possibility to prioritise. For normal operation, converters can be prioritised, while in case of a heavy system disturbance, the system stability can be prioritised. If many converters are operated that way, large voltage deviations can effectively be avoided.

If zero droop constant (constant voltage control) is avoided, the DC voltage maintains its function as an information carrier which can be measured and which contains information about a possible disturbance of the balance.

New converters can be added to a undead-band droop controlled system without changing the control of the existing converters. The undead-band droop controllers of the new converters can be tuned individually depending on their capabilities and limitations.

This control method operates with a minimum of required communication. A temporary loss of communication can be handled, since the converters receive only their general setpoints from a central system control. The real setpoints for the inner control loops are determined locally, based on the received general setpoints. Even if wrong general setpoints are received, stability is not necessarily lost; the central controller cannot directly force the converters to behave in a malicious way.

This control method is well suited to achieve high reliability standards due to the distributed control approach.

The autonomous converter control concept, as described in [Barker and Whitehouse, 2010], has later been modified in [Barker and Whitehouse, 2012a]. This modified version is very similar to undead-band droop control.

Also another large manufacturer of HVDC converters mentioned informally, that a similar concept is being considered. However, there are no official statements or publications available.

The earlier developed AC frequency control method (Section 3.6) can be seen as a basis for the later developed DC voltage control method (Section 4.5). The basic principle is the same: Proportional control with a control gain increase for large deviations of the input signal. The detailed implementation of that principle is significantly different though. The main differences are:

- The AC frequency control method has a strong differential control part. This requires significant low pass filtering of the input signal (grid frequency). Such filtering with a long time constant is only possible due to the stiffness of the AC frequency. DC voltage can fluctuate much faster, so the idea of differential control has been discarded.

- The DC voltage control method is meant to control the DC voltage in a system. The AC frequency control method is only meant to assist existing frequency control.
- The AC frequency control method relates the control output to the output setpoint, while the DC voltage control method relates it to the rated output. This clearly indicates the priorities. The relation to the setpoint gives priority to the individual converter, while a relation to the rated output gives priority to the entire system.

The next step in the development of undead-band droop control will be to implement it on the final version of the CIGRE B4 DC Grid Test System. Results could be compared with other control methods applied on the same reference test system.

Chapter 5

Conclusion

The changes in how electric energy is produced and consumed directly lead to changing requirements for the electric power transmission infrastructure. In northern Europe significant amounts of additional transmission capacity will be required, especially offshore in the North Sea region. The construction of the North Sea Super Grid is seen by many as the best solution for future high power long distance transmission in the region. The NSSG will probably also extend onshore towards load centres, eventually forming the European Super Grid.

HVDC technology has significant advantages for high power long distance transmission, especially when power cables are used instead of overhead lines. Since overhead lines cannot be applied offshore, HVDC is the best technology for the NSSG and the ESG. Voltage source converter technology is well suited for HVDC systems with more than two terminals.

Even though HVDC system normally are capable of transferring power in both directions, unidirectional systems should be considered for the NSSG. The developed method for identifying network branches with partly unidirectional loading can be applied for this task. Here unidirectional HVDC systems can be applied without reducing operational flexibility. The aspects of unidirectional loading should carefully be assessed, to not miss possible technical and economic advantages of unidirectional HVDC systems.

Offshore nodes of a HVDC-based super grid could be both AC or DC. AC is the state of the art, but DC might offer advantages in the future. The NSSG will therefore consist of both AC and DC technologies and could be seen as a hybrid (neither AC nor DC) grid, but the share of these technologies is not known yet. Meshed grid structures offer the most advantages for super grids, but they also lead to the biggest challenges.

The developed CIGRE B4 DC Grid Test System can serve for a variety of different studies concerning DC grids. The test system will be valuable to the research community within and outside CIGRE B4.

Balancing control is one of the challenges regarding DC grids, and it has been given special attention in this thesis.

HVDC systems were until now always limited in size (few nodes) and therefore complexity and could therefore be treated and controlled in a deterministic way. The known control principles for HVDC systems are not suitable for large DC grids.

AC systems like the interconnected continental European power system can have a very large number of nodes. The utilised control principles are well suited for large systems, but they cannot directly be applied to DC systems. However there are some significant similarities between AC and DC balancing control, and lessons can be learned. Therefore, AC balancing control has also been addressed in this thesis.

As AC power systems are undergoing changes, balancing control in AC power systems is also undergoing changes. This is mostly due to the large-scale deployment of power electronic systems. This development is highly relevant for DC grids, because they will be dominated by power electronic components.

These power electronic systems can have a positive or negative influence on grid frequency stability. The example of photovoltaic generation systems in Germany has shown how inadequate control design of power electronic systems can endanger power system frequency stability.

The newly developed control method for power electronic systems integrates AC grid frequency support functions. Power electronic grid assets with this control method have an enormous potential to contribute to power system frequency stability. This control method can be seen as a basis for the later developed undead-band droop control method.

The balance in a DC system should not be considered as a power balance (as done in AC systems) but as a current balance. The best balance indicator in a DC system is the DC voltage. The relationship between voltage and current is linear.

The best and most natural way to influence the DC voltage and therefore the DC current balance with control is to use DC current as a control base. This is breaking with the state-of-the-art control concepts for HVDC converter stations which are based on active and reactive power and not on DC current. This linear control approach is the best option to address the linear balance task.

The different control methods that have been proposed in the literature can be seen as special cases of droop control. These methods are either linear or piece-wise linear. Conceptual similarities have enabled for a systematic classification of these methods.

HVDC converter stations with linear control can be modelled on the DC side as Thevenin and Norton equivalent circuits. For non-linear power-based control, this simplified models can only be applied in linearised conditions around the operating point. For piece-wise linear control concepts, those models only hold within the segment where the operating point is located.

A new generalised control method for voltage control in HVDC grids called undead-band droop control has been developed and proposed in this thesis. It is based on the conceptual similarities of the other control methods and represents a general piecewise linear controller. This method combines the advantages of the existing methods. It can also serve as a generalised control framework as the other methods can be seen as specific implementations of it. Its definition is general and flexible, and it can therefore unify the voltage control methods, and serve as a general framework for DC voltage control.

It is however difficult to separate DC voltage control and AC frequency control. Both are system balancing control mechanisms for power systems and a HVDC converter station is the interface between an AC and a DC system. Any control action to balance one side will automatically be a disturbance to the other side. It is therefore useful to implement a combined balancing control for the AC and DC sides.

5.1 Outlook

System protection is probably the most prominent remaining unsolved issue when it comes to the operation of HVDC grids. It is not only the often mentioned DC circuit breaker that is likely to be needed, but also a protection concept as a whole. Before reliable and affordable protection schemes are available, the implementation of meshed DC structures seems questionable.

A standardised DC voltage level (as it exists for AC in Europe) is also needed to enable the construction of a super grid. As DC-DC converters are significantly more expensive than AC-AC transformers, there would be economic disadvantages if many different voltage levels are connected together.

Also an operational concept for the voltage profile in meshed HVDC grids is still missing. A simple economic view would lead to the as-high-as-possible concept for the voltage to minimise transmission losses. However, this is not the correct method to operate any important infrastructure. The threat of outage-induced over-voltages needs to be addressed very carefully. Unlike AC overhead lines, short-term over-voltages can have severe consequences on DC cables.

The next step in the development of undead-band droop control would be to implement it on the final version of the CIGRE B4 DC Grid Test System. Results could be compared with other control methods applied on the same reference test system.

A validation of an electromagnetic transient simulation software platform would also be valuable, as the applied average value simulations, that have been performed, do not necessarily capture all relevant phenomena. System oscillations are an issue that needs to be addressed carefully. Damping in a HVDC system is not likely to be good, due to significant line reactances and converter and cable capacitance, in combination with low line resistance. The situation might even become more complicated if DC inductors are applied as fault current limiters as part of a future protection plan.

HVDC converter technology has seen rapid changes in the last few years. This makes the assessment of system oscillation more difficult, since there is no established standard for converters and control at the moment, which could be used for general stability assessment.

The concepts on integrated AC frequency control support (Section 4.6) should also be validated with computer simulations. This could be done with the developed test system. However, this test system has a clear focus on the DC side, and a more complex AC+DC grid test system might be needed for a good validation.

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Appendix A

Derivation of Equations

Two equations are derived in Section 4.3.1.1, Equation 4.7 and Equation 4.10. The details of the derivation can be found here.

A.1 The P-V Relation for Current-Based Droop

Equation 4.7 is derived, based on Equation 4.6

$$\Delta I_I = \frac{1}{k_I} \Delta V \tag{A.1}$$

$$I_I - I_{set} = \frac{1}{k_I} \left(V - V_{set}\right) \tag{A.2}$$

$$V \left(I_I - I_{set}\right) = V \frac{1}{k_I} \left(V - V_{set}\right) \tag{A.3}$$

$$V I_I - V I_{set} = \frac{1}{k_I} \left(V^2 - V V_{set}\right) \tag{A.4}$$

$$V I_I - V I_{set} = \frac{1}{k_I} \left(V^2 - 2V V_{set} + V_{set}^2\right) + \frac{1}{k_I} \left(V V_{set} - V_{set}^2\right) \tag{A.5}$$

$$V I_I - V I_{set} = \frac{1}{k_I} \left(V - V_{set}\right)^2 + \frac{V_{set}}{k_I} \left(V - V_{set}\right) \tag{A.6}$$

$$V I_I - V_{set} I_{set} = \frac{1}{k_I} \left(V - V_{set}\right)^2 + \frac{V_{set}}{k_I} \left(V - V_{set}\right) + V I_{set} - V_{set} I_{set} \tag{A.7}$$

$$V I_I - V_{set} I_{set} = \frac{1}{k_I} \left(V - V_{set}\right)^2 + \frac{V_{set}}{k_I} \left(V - V_{set}\right) + I_{set} \left(V - V_{set}\right) \tag{A.8}$$

$$V I_I - V_{set} I_{set} = \frac{1}{k_I} \left(V - V_{set}\right)^2 + \left(\frac{V_{set}}{k_I} + I_{set}\right) \left(V - V_{set}\right) \tag{A.9}$$

$$P_I - P_{set} = \frac{1}{k_I} \left(V - V_{set}\right)^2 + \left(\frac{V_{set}}{k_I} + \frac{P_{\text{set}}}{V_{\text{set}}}\right) \left(V - V_{set}\right) \tag{A.10}$$

$$\Delta P_I = \frac{1}{k_I} \Delta V^2 + \left(\frac{V_{\text{set}}}{k_I} + \frac{P_{\text{set}}}{V_{\text{set}}}\right) \Delta V \tag{A.11}$$

$$\Delta P_I = \left(\frac{V_{\text{set}}}{k_I} + \frac{P_{\text{set}}}{V_{\text{set}}}\right) \Delta V + \frac{1}{k_I} \Delta V^2 \tag{A.12}$$

A.2 The I-V Relation for Power-Based Droop

Equation 4.10 is derived, based on Equation 4.9

$$\Delta P_P = \frac{1}{k_P}\Delta V \tag{A.13}$$

$$P_P - P_{set} = \frac{1}{k_P}\left(V - V_{set}\right) \tag{A.14}$$

$$V I_P - V_{set} I_{set} = \frac{1}{k_P}V - \frac{1}{k_P}V_{set} \tag{A.15}$$

$$V I_P = \frac{1}{k_P}V - \frac{1}{k_P}V_{set} + V_{set} I_{set} \tag{A.16}$$

$$I_P = \frac{1}{k_P} - \frac{1}{k_P}\frac{V_{set}}{V} + \frac{V_{set}}{V}I_{set} \tag{A.17}$$

$$I_P - I_{set} = \frac{1}{k_P} - \frac{1}{k_P}\frac{V_{set}}{V} + \frac{V_{set}}{V}I_{set} - I_{set} \tag{A.18}$$

$$I_P - I_{set} = \frac{1}{k_P} - I_{set} - \left(\frac{1}{k_P} - I_{set}\right)\frac{V_{set}}{V} \tag{A.19}$$

$$I_P - I_{set} = \left(\frac{1}{k_P} - I_{set}\right)\left(1 - \frac{V_{set}}{V}\right) \tag{A.20}$$

$$I_P - I_{set} = \left(\frac{1}{k_P} - I_{set}\right)\frac{V - V_{set}}{V} \tag{A.21}$$

$$I_P - I_{set} = \left(\frac{1}{k_P} - I_{set}\right)\frac{V - V_{set}}{V - V_{set} + V_{set}} \tag{A.22}$$

$$\Delta I_P = \left(\frac{1}{k_P} - I_{\mathrm{set}}\right)\frac{\Delta V}{\Delta V + V_{\mathrm{set}}} \tag{A.23}$$

Appendix B

Publications regarding Chapter 2

Technical Aspects of the North Sea Super Grid

Is not included due to copyright

Benefits of Asymmetric HVDC Links for Large Scale Offshore Wind Integration

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***Abstract*—The large remote offshore wind clusters that are planned in the North Sea will most likely be connected with a meshed HVDC grid. Power will mostly flow from the offshore wind clusters to shore, creating asymmetrical requirements for the HVDC links that will consist of several parallel HVDC systems. To realise an asymmetrical link, some of those systems could be designed unidirectional, resulting in possible changes and simplifications (especially to the protection system). Assessment of a future scenario has shown that 42% of the HVDC systems can only be operated unidirectional. The remaining systems could in theory be used both directions, but power flow optimisation has shown, that this will in many cases not happen. A first cost calculation has shown that almost 6% of the investment cost can be saved when asymmetric design is implemented. This indicates the need to consider asymmetric design and to develop unidirectional HVDC systems.**

***Index Terms*—Offshore Wind Farm, HVDC, DC Grid, Subsea Cables, VSC, CSC, Hybrid HVDC.**

I. Introduction

The massive deployment of offshore wind farms in the North Sea, of which many are located far away from shore, will require a large number of subsea cables to transfer the produced electric power to shore. A stronger inter-connection of the three synchronous zones around the North Sea is also desired to improve market coupling and to enable more efficient balancing of wind generation fluctuations.

The number and the large power rating of the needed links imply the consideration of an advantageous meshed grid structure [1]. Several studies like [2-5] have indicated, that a meshed grid offers economic benefits compared to a solution consisting only of point to point connections. Moreover the countries around the North Sea have agreed in the creation of the North Sea Super Grid (NSSG) under the North Seas Countries Offshore Grid Initiative (NSCOGI) [6].

Most of these future links need to utilise HVDC technology due to the long distances involved. Several of the HVDC links will need high power ratings, which cannot be supplied by a single HVDC system. Reliability requirements also oppose the use of single systems for important transmission corridors. These important HVDC links will consist of several parallel HVDC systems. Conventional HVDC systems are designed to be able to transfer power in both directions offering operational flexibility.

The NSSG is a pioneer project leading to new requirements for HVDC links. All connections must of course be cables rather than overhead lines. On several of the links, the power flow will be highly unbalanced, meaning that power will mostly flow from the offshore clusters (containing the wind farms) to shore. This property is not related to specific layouts, future scenarios or technological solutions. It is purely based on the fact, that the offshore cluster will have a large power surplus. Since the application of those HVDC links is asymmetrical, an asymmetrical design of the links should be considered. An asymmetrical HVDC link can be realised by designing some of the parallel systems unidirectional.

II. Unidirectional HVDC Systems

There are three types of HVDC systems: VSC, CSC and hybrid HVDC. VSC is likely to be the dominating technology when it comes to offshore projects [7, 8]. Hybrid HVDC consists of a VSC on one side and a CSC on the other side of the line. Since VSCs operate at fixed voltage with fixed polarity and CSCs with variable unidirectional current, hybrid is naturally unidirectional. While VSC and CSC have been implemented many times, hybrid is still in an early research state. The voltage and current properties of the different HVDC types is given in Table I. A technology overview can be found in [1].

TABLE I
HVDC Technology Overview

HVDC	Voltage		Current	
Type	Amplitude	Sign	Amplitude	Sign
Bi.-VSC	Fixed	Fixed	Variable	Variable
Uni.-VSC	Fixed	Fixed	Variable	Fixed
Bi.-CSC	Fixed	Variable	Variable	Fixed
Uni.-CSC	Fixed	Fixed	Variable	Fixed
Uni.-Hyb.	Fixed	Fixed	Variable	Fixed

All HVDC types operate at fixed voltage amplitude and variable current amplitude. VSC systems usually have variable current direction while CSC systems have variable voltage polarity, but these variabilities are not the case for

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unidirectional systems. All unidirectional systems are operated in a similar manner, not depending on the applied converter.

The disadvantage of unidirectional systems is obvious: Power flow direction cannot be reversed. The assessment of the advantages is more complex and some indications are given in this section.

The main advantage is a simplification of the protection system for unidirectional systems. State of the art point to point HVDC systems do not have a DC protection system. The entire pole is disconnected on the AC side in case of a DC cable fault. For large meshed HVDC grids a system shut down is not acceptable creating the need for DC protection and DC circuit breakers.

AC circuit breakers can always break current in both directions, since a clear current direction does not exist for AC. For DC circuit breakers, the current direction is highly relevant. The HVDC converter current for a cable fault is displayed in a simplified way in Fig. 1. Important for the developed protection concept is the fact, that the current on the receiving end crosses zero, while the sending end current keeps its direction. For the unidirectional system, sending end and receiving end are fixed. The protection system can therefore be tailor-made, taking this fact into account.

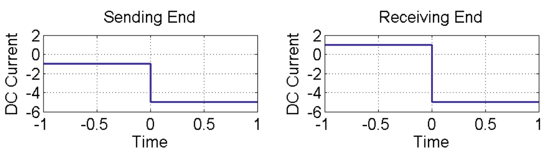

Fig. 1. DC fault currents

To explain this concept, a section of the future NSSG is shown in Fig. 2. The illustration shows a large wind farm connected to the NSSG via two parallel HVDC systems. One of those is bidirectional, to be able to black start the wind farm, while the other is unidirectional, to transfer bulk power from farm to grid. Focus will of course be on the unidirectional system; the bidirectional system serves as a reference.

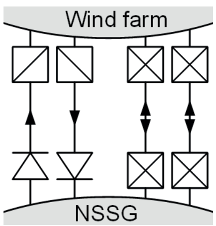

Fig. 2. Section of the NSSG

The bidirectional system needs bidirectional circuit breakers on both ends of both cables, which consist of a separate stack of IGBTs and anti-parallel diodes for each direction [9]. This leads to a total of 8 IGBT stacks with 8 stacks of diodes.

The unidirectional system needs unidirectional breakers on the sending ends, which would only need a single stack of IGBTs and anti-parallel diodes (reduction by 50%). The natural current zero at the receiving end converters makes protection even more simple, where diodes can be used for protection. The unidirectional system only needs two unidirectional circuit breakers and two diodes, leading to a total of 2 IGBT stacks and 4 diode stacks. This leads to a significant reduction in size, mass, losses and cost.

Another advantage of unidirectional systems: The receiving end converter voltage can be rated a bit smaller than the sending end converter, taking transmission losses into account. Additionally to these general advantages, there are some technology specific advantages, which are explained in the following.

A. *VSC HVDC*

One significant disadvantage of VSC is that a DC voltage collapse caused by a short circuit cannot be handled. If DC voltage drops below AC voltage, the converters diodes start conducting. In this situation the converter behaves like an uncontrolled diode rectifier and feeds energy to the fault. To avoid this, fast protection based on diodes rather than circuit breakers for the receiving end converter would be a great advantage.

B. *CSC HVDC*

Considering CSC a significant advantage of unidirectional cable systems would result from the fixed voltage polarity. A unidirectional setup would enable the use of XLPE-cables, which offer several advantages compared to mass impregnated cables.

C. *Hybrid HVDC*

Hybrid HVDC is naturally unidirectional, and could offer benefits for the NSSG due to its asymmetric nature, which fits well with the asymmetrical utilisation of the HVDC links within the NSSG. The compact and flexible VSC could be placed offshore and the efficient and robust CSC onshore.

III. Identification of Inherently Asymmetric Links

The NSSG will have a huge power surplus due to the large number of wind farms and the small amount of total offshore loads. This surplus leads to a preferred power flow direction, from offshore cluster to shore. To design asymmetric HVDC links, it is important to calculate the amount of unidirectional capacity within the link.

An offshore cluster is connected to n HVDC links (which can consist of several parallel cables). The power rating of those links are called P_i while P_1 is the most powerful link. The total generation capacity P_{Gen} of the cluster is mostly based on the connected offshore wind farms, but could also include other sources like wave power plants or UPS-systems. The maximum total load P_{Load} mostly consists of the consumption of connected offshore oil&gas platforms and the internal loads of the wind farms.

The maximum power for the largest link P_1 of a cluster for import into and export from that cluster is:

$$P_{1,Import} = P_{Load} + \sum_{i=2}^{n} P_i \qquad (1)$$

$$P_{1,Export} = P_{Gen} + \sum_{i=2}^{n} P_i \qquad (2)$$

If both of those values are smaller than P_1 the link is overrated. If none of the values is smaller, the link can be fully loaded in both directions. The interesting case is when only one of those values is significantly smaller than P_1. This indicates the link can only be fully loaded in one direction and is overrated in the other direction, resulting in asymmetric requirements for that link.

In the studied case of the NSSG, this would typically be the case for the links between large offshore wind clusters and the nearest shore. It directly appears natural, that a scenario where the offshore wind cluster imports large amounts of power from the shore is impossible, since that power cannot go anywhere. This defines the inherently unidirectional capacity: Transmission capacity which physically cannot be used to transfer power in reverse direction (from shore to offshore). This capacity can be designed unidirectional without degrading operational flexibility of the entire system.

The inherently unidirectional part of P_1 in this case is:

$$P_{1,Uni} = P_1 - P_{1,Import} \tag{3}$$

IV. Application on a NSSG Scenario from the WindSpeed Project

To apply the developed method, the “Grand Design”-scenario from the IEE-EU WindSpeed project has been chosen [4, 10, 11]. The IEE-EU WindSpeed project, which is funded under the Intelligent Energy for Europe (IEE) programme, assesses the potential for further development of offshore wind energy (OWE) in the Central and Southern North Sea. The overall objective of the project is to develop a 2020-2030 roadmap for the deployment of OWE in this region of the North Sea as bounded by Belgium, Denmark, Germany, the Netherlands, Norway and the United Kingdom.

A. The “Grand Design" Scenario

The “Grand Design” scenario is the most pro-offshore wind scenario considered in this project. In this scenario it is assumed that high level trans-national coordination for the development of an offshore grid is possible. In addition, the possibility of zero “minimum” production for generation sources like oil, gas and coal is permitted. The phasing-out of these carbon-emitting generation sources by large scale deployment of offshore wind energy is therefore investigated in this scenario. Complete phase-out of nuclear power is assumed.

A maximum possible potential (~88GW) for the installed capacity at the offshore clusters is assumed. The phasing-out of nuclear power assumed in this scenario e.g. implies a significant reduction of the available generation capacity for the UK.

Fig. 3 shows the offshore wind clusters that are far away from shore, and therefore considered for the North Sea Super Grid. All near shore wind farms do not appear in the optimization, since they are radially connected to the onshore grids via AC cables. Eight offshore nodes are considered.

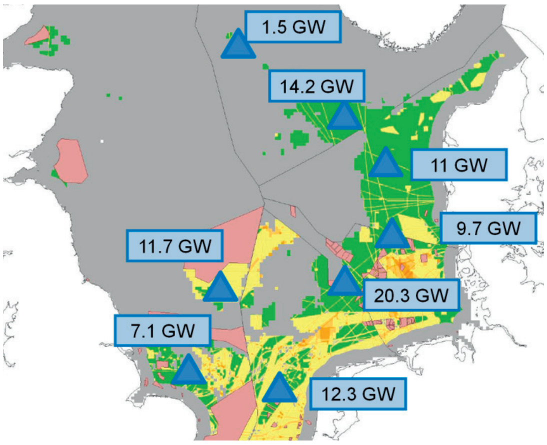

Fig. 3. Offshore wind clusters (from [10])

In Table II the ratings of the clusters are shown. The wind farm ratings are directly taken from the scenario. The offshore load ratings are estimations of the wind farm internal loads plus connected offshore oil&gas platforms. Since the offshore loads are small compared to the offshore generation capacity, the estimation does not significantly influence the outcome of the calculations.

TABLE II
Offshore Cluster Ratings

Offshore Cluster	Generation [MW]	Load [MW]
Ijmuiden	12300	500
Hornsea	7100	600
Doggerbank	11700	200
Gaia	20300	300
DanTysk	9700	100
Dansk	11000	100
Norsk-S	14200	400
Norsk-SW	1500	300

B. The Optimised NSSG Structure

The optimization algorithm has found the grid topology shown in Fig. 4. Of the eight offshore nodes, only five are connected to a meshed offshore grid structure. Two are connected in a small structure between continental Europe and the UK. One is connected in the middle of a point to point connection between Scandinavia and the UK.

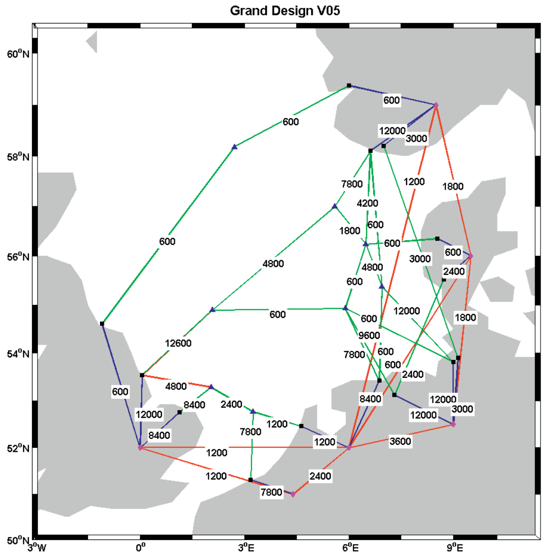

Fig. 4. Optimised grid structure (from [10])

From this complete grid topology the meshed part is extracted and shown in Fig. 5. The meshed grid contains a total of 69 GW of HVDC links.

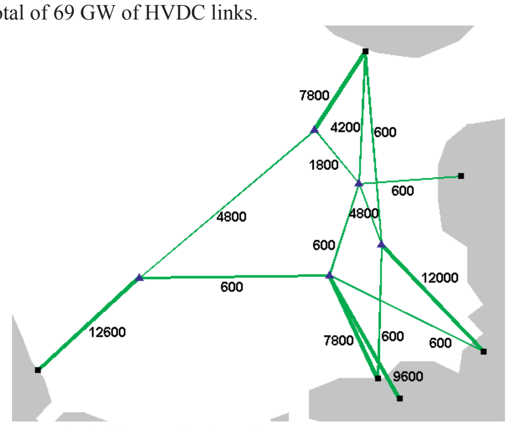

Fig. 5. Meshed offshore grid (adapted from [10])

Most of the transmission capacity of the meshed offshore grid is concentrated in the four strongest HVDC links of the system (indicated by thick lines in Fig. 5). The two links from the Gaia node to Germany and the Netherlands are seen as one link, since their connection points onshore are nearby. Basic information for those four links is given in Table III.

TABLE III
MESHED OFFSHORE GRID LINK INFORMATION

Node	Strongest Link to	Length [km]
Doggerbank	England	197
Gaia	Ger. + Neth.	164
DanTysk	Germany	193
Norsk-S	Norway	154

C. *Unidirectional HVDC Links*

The meshed offshore grid incorporates five offshore nodes, of which four fulfil the developed criteria that the strongest link can only be fully loaded towards shore. The most important parameters of those four links are shown in Table IV. Those four links contain a total unidirectional power of 29GW, which is 58% the capacity of those links. Compared to all links of the meshed offshore grid, it is 42% of the total HVDC transmission capacity.

TABLE IV
MESHED OFFSHORE GRID LINK RATINGS

Node	P1	P2-∞	Load	P1-Bi	P1-Uni
Doggerbank	12600	5400	200	5600	7000
Gaia	17400	1800	300	2100	15300
DanTysk	12000	6000	100	6100	5900
Norsk-S	7800	6600	400	7000	800
Total	49800	------	-------	20800	29000

V. Additional Unidirectional Transmission Capacity

If other HVDC systems than the ones identified with the method from Section III are designed unidirectional, the operational flexibility of the entire DC grid will somehow be reduced. In this section, it is analysed if this flexibility reduction would have relevant consequences for system operation.

A detailed power flow study considering a variety of scenarios and network conditions can identify additional interconnection capacity, which could in theory be used in both directions, but never actually is used that way under any realistic operating condition. Taking the power flow results from the [10], it can be seen, that most of the bidirectional capacity is actually used unidirectionally. As an example, the duration curve of the HVDC link between the Doggerbank and England is shown in Fig. 6. This link has a bidirectional part of 5600MW as seen in Table 3, but, since the flow for this link is always positive the bidirectional capacity is not used during a single hour during the entire year calculated.

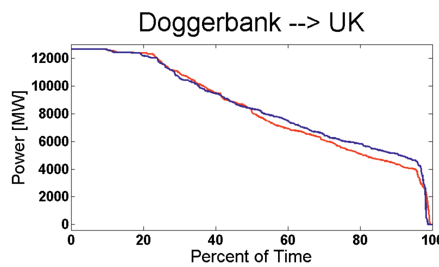

Fig. 6. Duration curve of the Doggerbank-England connection (from [10])

These findings can even increase the possible benefits of the asymmetric link approach. It gives a clear indication: A significant share of the remaining 58% or 40GW bidirectional capacity does not need to be bidirectional. A unidirectional setup for some of those HVDC systems would degrade the theoretical capabilities of the system, but it might have no significant impact on system performance. Therefore unidirectional HVDC systems should also be considered for not inherently unidirectional capacity.

There is no clear method to determine how much bidirectional capacity the link from the UK to the Doggerbank should have. But still, 5600MW appears even under very strict availability and redundancy requirements overrated for a wind cluster black start. Massive power exports from the UK to other countries at a time, when power production at the Doggerbank is very low, also seem unrealistic.

If more than the inherently unidirectional capacity should be designed unidirectional, deeper investigation of these matters is required. It is not further addressed in this article.

VI. Economic Benefits and Cost Calculation

The identified total amount of HVDC transmission capacity which can only be loaded in one direction indicates the need for asymmetric HVDC links. For all types of HVDC systems, a unidirectional setup results in possible changes and simplifications, which in turn result in cost savings and possibly other advantages like increased reliability. Due to this massive investment volume, only slight changes and improvements can lead to significant cost savings.

Assumptions on cost data for cables, converter stations, switchgear and offshore platforms are used to calculate the investment costs for electrical infrastructure as provided in [10] and listed in Table V.

TABLE V
Cost data – 600MW unit (from [10])

Cable/Trench/laying cost	0.76 M€/km
Cable project fixed charge	5.0 M€
Converter onshore	136.1 M€
Converter and platform offshore	167.2 M€
DC protection onshore, per cable	45.36M€
DC protection offshore, per cable	55.73M€

The cost for DC breaker and switching gear onshore (offshore) is assumed to be a 1/β fraction of the cost for AC/DC converter station (and platform offshore) onshore. The β equal to 3 has been used [10]. This value corresponds to a situation where point-to-point and meshed solutions can appear simultaneously, allowing for hybrid offshore grid strategies. The value 1/3 also relates to the fact that a regular 2-level converter consists of 6 IGBTs, while a solid state DC circuit breaker consists of 2 IGBTs (one for each direction).

Both cables and converter stations are built in whole units. The implemented block capacity is 600MW and multiple blocks can be built. In this case, each new block incurs the full costs defined in Table V.

The data of Table V has been used to calculate the costs of the connections indicated in Table IV (considering only inherently unidirectional capacity). First the costs associated with investment needed to deploy of the whole P_1 capacity as fully bidirectional are calculated. Then as a second step the same calculation is done for the $P_{1,Bi}$ capacity which is the minimum indicated bidirectional capacity needed according to our analysis. Finally the costs associated with the investment of the unidirectional part $P_{1,Uni}$ are considered. In this case no DC breaker is assumed on the onshore side of the connection and only offshore DC breakers are assumed. This means that the cost of each 600MW unit is reduced by 45.36M€.

The results of the cost calculation are given in Table VI. The cost benefit of using both bi- and unidirectional solutions for the four relevant HVDC links is 2694M€ which is almost 6% cost reduction from the total cost for the case with all connections being bidirectional. The total figures should be taken carefully due to the number of assumptions considered when calculating the costs and should not be taken as final values reflecting a detailed calculation for the investment decision of developing these connections. Most relevant for our article is the ~6% value of the relative benefit due to the use of unidirectional technology. The benefit would even be larger if the additional unidirectional capacity identified with the power flow was regarded.

TABLE VI
Costs and benefits

Technical Solution	Investment Cost [M€]
All Bidirectional	45409
Bi- and Unidirectional	42715

VII. Conclusion

The technical requirements for HVDC links depend highly on the application, and the NSSG will have asymmetrical requirements for several connections. Even though regular design is symmetrical, an asymmetric design should be considered because it leads to reduced investment costs.

An optimistic future scenario for the North Sea has been chosen, which includes a meshed offshore NSSG with a total of 69GW of HVDC systems. 42% of those systems can only be operated with power transfer from offshore to shore. The remaining systems could in theory be used both directions, but power flow optimisation has shown, that this will in many cases not happen. This significant amount of unidirectional capacity exists due to the large power imbalance within the offshore grid (lots of wind farms and very few loads), and is not based on specific assumptions or scenarios.

The unidirectional capacity found is mostly within four strong HVDC links with many parallel systems, of which some can be designed unidirectional. A first cost calculation has shown that almost 6% of the investment cost for those links can be saved when asymmetric design is implemented. These cost calculations are based on estimations and the accuracy of the calculated numbers should not be overestimated. The goal is rather the show the need to consider asymmetric design and to develop unidirectional HVDC systems. The most important points are:

- Many HVDC systems of the NSSG will be operated unidirectional
- These systems should also be designed unidirectional
- Protection for unidirectional HVDC systems is less complicated
- Relevant cost savings are achievable with asymmetric HVDC link design

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IX. Biographies

Til Kristian Vrana was born in Hamburg, Germany in 1982 and graduated from the Academic School of the Johanneum in Hamburg in 2001.

From 2002 on he studied at RWTH Aachen University in Germany, where he received his Bachelor in electrical engineering and information technology in 2005 and his master in electric power engineering in 2008.

Since 2009 he is pursuing a PhD with focus on offshore electric grids at the Norwegian University of Science and Technology in Trondheim.

Daniel Huertas-Hernando was born in Segovia, Spain May 6 1975. Daniel has a Ph.D. in Theoretical Solid State Physics from Deft University of Technology (TUDelft) and has worked as Postdoctoral Researcher at Yale University and the Norwegian University of Science and Technology (NTNU) before joining SINTEF Energy Research in 2009.

At SINTEF Energy Research his activity focus on grid connection of large scale offshore wind power, wind forecast uncertainty, balancing of variable renewable generation and market integration and system operation.

Olav Bjarte Fosso graduated from The Department of Electrical Engineering, the Norwegian Institute of Technology, Trondheim, Norway with the M.Sc in 1985, and received his Ph.D. in electrical engineering at the same institute in 1989.

From 1989 to 2002 he has been with SINTEF Energy Research except for an employment in 1997/1998 at Powel (a company providing decision support tools in a deregulated market environment).

A main responsibility at SINTEF Energy Research has been development of tools for analysis and decision support in transmission and power production systems. The topics covered are use of optimization techniques in short- and mid-term hydro scheduling in deregulated market systems, voltage stability analysis, dynamic simulations and sensitivity studies.

Since March 2002, he holds a full-time professor position at the Norwegian University of Science and Technology (NTNU) and a part-time position at SINTEF Energy Research as Scientific Advisor.

A EUROPEAN SUPERGRID: PRESENT STATE AND FUTURE CHALLENGES

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Abstract – Europe has a clear objective of obtaining a large share of wind power in the overall energy mix. A significant part of the installed wind power capacity will come from offshore wind farms. As an alternative to connecting every wind farm to the onshore grid separately, the 'supergrid' concept has been proposed. A supergrid would allow international trade and balancing, and can accommodate renewable energy sources, such as concentrated solar power and offshore wind energy. In this paper, we give an overview of technical challenges associated to meshed multi-terminal direct current supergrids, and present alternatives and a roadmap that could expedite the development of a European supergrid.

Keywords: Supergrid, HVDC

1 INTRODUCTION

The development of a 'supergrid' has been hailed as a means to attain the ambitious renewable energy targets Europe has set. The supergrid idea is finding acceptance in academic, industrial and political circles. The basic definition of a supergrid can be derived directly from the word's etymology: a supergrid is a grid which resides 'on top' of the existing grid. This basic definition is important in that it immediately makes clear that the supergrid is not just an extension of the existing grid, but a whole new layer or backbone, or at the very least a new independent structure, connected to the existing grid. The definition of supergrid as an overlaying grid is very broad. To arrive at a workable definition, it has to be further specified what is meant by a 'supergrid'. A supergrid could be based on Alternating current (AC) or Direct Current (DC), it could be offshore or onshore, fully meshed or with alternative topologies integrating point-to-point links, or a combination of all of the above. In section 2 it is argued that in the European context a number of key drivers will lead to many offshore developments such as wind farms and interconnectors. Therefore, a European supergrid will have a large offshore part that could rationalize the offshore developments. Voltage Source Converter High Voltage Direct Current (VSC HVDC) is often put forward as the ideal technology for supergrids, as VSC HVDC supports multi-terminal operation. However, as we will explain in section 4, many technological challenges associated to multi-terminal VSC HVDC systems remain. One should therefore not lose sight of other supergrid options (section 5). In view of the numerous offshore developments already existing, 'green field' approaches to the conception of a supergrid seem questionable. It is more likely that the development of the supergrid will follow an organic process as explained in section 6. It is finally argued that the alternatives could well expedite supergrid development as they are based on proven technology. In section 7, a selection of ongoing initiatives on supergrids is given. Special attention goes to the supergrid proposals of Friends of the Supergrid and Medgrid, which have a paper in the invited lecture on supergrids in the PSCC 2011 conference.

2 DRIVERS FOR THE SUPERGRID

The supergrid will not serve a single purpose. In fact, there is a wide variety of drivers, which are introduced in this section.

2.1 Offshore Wind Development

According to the European Wind Energy Association (EWEA) scenarios, 40 GW offshore wind farms will be installed by 2020, and 150 GW by 2030 [1]. The fast developing offshore wind projects call for a new type of electric infrastructure: offshore transmission systems. EWEA identifies the main markets for offshore wind farms as the United Kingdom, Denmark, The Netherlands, Sweden, Germany, Belgium, and Norway. It is thus expected that future offshore developments are mainly concentrated in the North and Baltic Sea. Instead of connecting each wind farm to shore by a dedicated connection, it could be more efficient to collect offshore wind energy in an offshore grid that is connected to shore, or directly to the main load centers.

2.2 Large-scale Concentrated Solar Power

The objective of a diversified energy supply and the observation that a small part of the desert has enough solar energy potential to cover the electrical energy needs of the whole world, make a case for Concentrated Solar Power (CSP). The idea is to install large-scale CSP in the Sahara region, and to transmit the electricity it generates directly to European load centers. This would require a supergrid structure, linking Europe to Africa and the Middle East.

2.3 Interconnection for Balancing

A growing share of intermittent renewable in the grid leads to a number of problems, many of which were identified in The European Wind Integration Study (EWIS), a study conducted by the European TSOs [2]. In particular, the intermittent nature of renewable sources is considered as a huge problem. Balancing becomes more difficult as more uncontrollable sources such as wind energy are connected to the grid. Long distance transmission, interconnecting remote RES, are instrumental in balancing regional fluctuations. Harnessing the tremendous value of the storage capacity and flexibility of Norwegian hydro could be even more advantageous from a balancing perspective. A large European supergrid could not only connect offshore wind farms, but also a variety of other sources such as hydro power, CSP and even ocean energy in future.

2.4 Interconnections/Trade

A supergrid would not only be used for connecting offshore wind farms, but also for international trade. In Europe, a large number of submarine cables are already installed for international trading purposes, and more are planned. A supergrid spanning multiple and far away countries would increase the potential for international trade.

2.5 Bootstraps

TSOs are facing difficulties in getting permits to construct overhead lines. An alternative are offshore HVDC 'bootstraps' that link two onshore connection points. The idea has been proposed for the France-Spain interconnector, but was ultimately discarded. The UK Transmission System Operator (TSO), National Grid, considers two HVDC bootstraps, connecting Scotland and England on the west and east coast (Fig. 1). The bootstrap function is inherently present in a supergrid. A supergrid would combine the three functions of bootstraps, international trade and offshore wind farm connections.

Figure 1: Bootstraps (Figure extracted from [3]).

3 TECHNOLOGY

The main drivers described in the previous section give an indication of the requirements for the supergrid. The present section lists the requirements and the possible technological answers.

3.1 Requirements

Based on the applications that form the drivers for the supergrid, the technical requirements for a supergrid can be defined. A first requirement is long-distance transmission. A supergrid would connect renewable source from different, often remote regions. An example is concentrated solar power in the Sahara. A second requirement is that sufficient ratings can be achieved, to allow connection of large-scale renewable energy sources. A third requirement is the meshed nature of the supergrid. Meshing a transmission grid increases its overall reliability. When large-scale renewable energy sources are connected to the load centers, it is desirable that they do not rely on a single connection for the export of power. Lastly, it is clear that the European supergrid will have a significant offshore component. All equipment should therefore be suitable for offshore use.

3.2 Technological Answers

Much experience is gained in offshore power technology in the last years due to the increasing number of offshore projects, mainly offshore wind farms, but also offshore oil and gas rigs. In future commercial oceanic energy projects, harvesting tidal or wave energy may see the light of day. Moreover, vast experience exists in Europe on submarine connections, both in AC and DC technology. However, for supergrid applications, AC and classical HVDC systems reach their technological boundaries. AC cables require reactive compensation for large distance transmission, which is very inconvenient in offshore applications. Classical HVDC converter stations cannot be used offshore because they need a voltage source to commutate and because of their large footprint. VSC HVDC on the other hand, complies with all of the technological requirements for a supergrid. VSC HVDC can be used for long-distance transmission, it can be meshed and is used for the connection of offshore wind farms and oil rigs. While today the power ratings are not up to par with those of Current Source Converter (CSC) HVDC systems, they have been sufficiently developed to allow large-scale power transmission. VSC HVDC is therefore considered to be a major enabler of the supergrid.

4 CHALLENGES AND R&D NEEDS FOR MULTI-TERMINAL VSC HVDC BASED SUPERGRIDS

While VSC HVDC allows in theory easy multi-terminal operation, many technical challenges remain.

4.1 Operation of AC-DC Systems

Future HVDC transmission grids, either offshore or onshore, will have to be operated in parallel with AC transmission grids, thus creating hybrid transmission systems. The security and stability of those hybrid systems have to be handled both in normal and disturbed conditions, to maintain continuity of energy supply to domestic consumers and crossborder trade. Moreover, this continuity of service will have to be provided at “non-prohibitive” economic conditions for all parties involved. These are crucial pre-requisites for the feasibility of future HVDC grids, that might strongly influence the stakeholders decisions (TSO’s, regulators, governments, …) at the very beginning of the design process.

On one hand, HVDC grids will have to react “correctly” against disturbances affecting HVDC devices. On the other hand, as the DC and AC transmission grids will be operated in parallel, a harmonized and efficient coordination will have to be set up to control and limit any possible spreading of negative effects from AC to DC and vice-versa.

It should be kept in mind that dynamics will be the major key issue to deal with. This is the huge challenge TSO’s, developers and manufacturers have to meet together for a successful outcome in future decades.

4.2 DC Breakers

In existing two-terminal or point-to-point VSC HVDC connection, a DC fault is cleared by opening the AC circuit breakers. This circumvents the need for DC breakers. Note that the current control loop cannot limit the DC fault currents as the IGBTs are blocked and the diodes connected in anti-parallel to the IGBTs keep feeding the fault. Keeping the same protection strategy in a multi-terminal system would mean that the whole grid has to be shut down in order to clear a DC fault, which is unacceptable. A large supergrid connecting diverse renewable energy sources and load centers would be a critical infrastructure. It would be desirable to have the same criteria as for AC grids regarding reliability and availability. One desired feature would be selectivity: only the faulted line should be isolated, while the rest of the DC grid keeps operating. This necessitates DC breakers.

DC breakers are currently not yet available. However, manufacturers acknowledge the importance of DC breakers for supergrids and are working hard to release a first prototype.

4.3 DC Voltage Control

In VSC systems, it is imperative that DC voltage remain very close to the nominal voltage. Therefore, in a point-to-point VSC HVDC transmission system, one converter always controls the DC voltage. When the other converter changes its active power, the voltage controlling converter automatically changes its active power in such a way that the DC voltage remains at the nominal value.

In a multi-terminal network, wherein many converters can change the setpoint of their injected active power, the voltage controlling converter cannot always provide the power required to balance the network. In Fig. 2, a meshed four terminal DC network is shown. The bottom right converter is the voltage controlling converter. If the bottom left converter fails, the voltage controlling converter has to compensate for the reduced output by increasing its output from 100 MW to 200 MW. If the converter rating is below 200 MW, the DC voltage could rise to an unacceptable level if no provisions were made.

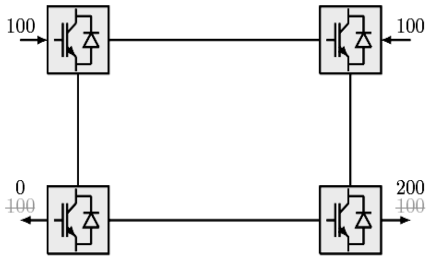

Figure 2: Voltage regulation in MTDC network.

It is obvious from the above discussion that a more elaborate voltage control method is needed in multi-terminal systems. Two methods are proposed in literature: voltage margin control and voltage droop control. In voltage margin control, the voltage is controlled by one converter, but aided by another one when it fails or when voltage becomes too low. In voltage droop control, all converters contribute to voltage control. The relative contribution of every converter to voltage control can be chosen [4].

4.4 Standardization and Interoperability

At present, standardization of HVDC systems is at its infancy and no initiative on standardization of multi-terminal DC systems exists. Nevertheless, standardization is an important issue, since the supergrid will incorporate a wide variety of facilities from different suppliers, some of them already existing, and has to cope with rapid advances in HVDC technology. Interoperability is a must, as different technologies and equipment from different manufacturers must be compatible. Moreover, the supergrid should be flexible and modular so that it can grow in an organic way.

Once the supergrid starts to emerge, a DC grid code must be available. At present, no attempt has been made to come up with a fully-fledged DC grid code. However, some grid codes, such as the grid code from the UK TSO, NGET, have been rewritten to cater for offshore grids. While still a far cry from a multinational supergrid grid code, such initiatives might spur the development of a DC grid code.

4.5 Protection

The availability of DC breakers is not enough to guarantee a high reliability of the DC grid protection. A suitable protection strategy needs to be available that can accurately detect and rapidly isolate the fault. The DC fault current will rise very rapidly in a DC network. Practically, the fault needs to be correctly detected within 1 ms and without using communication between the converter stations [5]. The problem is compounded by the fact that traditional AC protection methods are not applicable in HVDC networks.

Preliminary analyses on the protection of HVDC networks for off-shore wind farms have been discussed in the TWENTIES project (www.twenties-project.eu) launched in April 2010 and financed by EC funds in the FP7 framework ([6], [7]). The main concepts addressed and partial results achieved through first simulations, are summarized below.

- The simplest MTDC system is the three-terminal one, the most complex a meshed network. Many intermediate topologies can be designed in between. Radial connections of wind farms or point-to-point interconnectors are not HVDC grids, as they do not offer alternative paths to power flows in case a fault occurs on a cable. However they have to be considered up to 2020, as preliminary steps for further off-shore grid developments beyond 2020 and towards a "target network" still to be designed.
- Short-circuits on DC cables, and mainly pole-to-pole ones are the most severe faults to get through, in very few ms (<10ms). Substantial research work based on detailed dynamic simulations is therefore mandatory to better understand and characterize the physical phenomena occurring in a DC grid affected by a short-circuit.
- DC short-circuits can be subdivided into several classes, depending on the magnitude of the peak fault current and the range of di/dt. These parameters vary according to fault location on the DC grid and characteristics of the AC grid to which the DC grid is connected. Each class will require specific current breaking functions and / or different types of DC breakers.
- Protections commonly used for AC grids cannot be simply transposed to DC grids and have to be adapted to DC needs (overcurrent, distance, line current differential, cable directional, busbar current differential, ...). More specific protections coordinated with converter actions will probably have to be designed. Back-up and reclosing also need to be addressed in future work.
- The DC grid protection system has to be specifically designed for the DC technology (CSC, VSC, specific converters architecture) and grid topology (from three-terminal MTDC to a meshed network) under concern. It has to integrate the detection, selection and elimination of the faulty section in very few ms, taking into account the short-circuit classes (item 3).
- A robust and fast DC breaker is a crucial component of the protection system. However, the DC breaker alone will not be sufficient to properly clear short-circuits in future meshed DC topologies. The whole protection system including sensors, actuators and signal processing units also have to meet the required dynamics and accuracy.
- The converters and other equipments such as inductors can help limiting the fault peak current, leaving thus more room to the selective fault elimination process and making it easier and more reliable. The first generation of DC breakers will probably have to benefit from this conjunction of actions.
- Finally, the coupling of DC grids to AC grids will require careful coordination of protection schemes on both sides. More simulation work on reference events is still needed, and might show that AC protections have to be adapted to avoid fault current infeeds from AC to DC and vice versa.

5 ALTERNATIVE SUPERGRID STRUCTURES

However, a meshed, multi-terminal VSC HVDC system is not the only option for a supergrid. Especially in the North Sea, where new transmission infrastructure is needed in the near future, other concepts can be applied. This future offshore transmission system can generally be described by four levels (Fig. 3). The first level consists of the individual wind turbines. The second level is the wind farm collection grid that connects all wind turbines in the same wind farm. The third level is the cluster grid, which interconnects several wind farms. The third level can also accommodate loads such as oil rigs as shown in the figure, or other generation such as solar power or ocean power. Finally, long distance transmission to the main load centers or to other clusters is the fourth level. The levels three and four could constitute the first step of a supergrid. Levels one to three can use AC or DC technology, while level four uses DC due to the long distances involved. Taking into account the possibility of gradual organic growth of the supergrid, it is likely that it will contain AC parts.

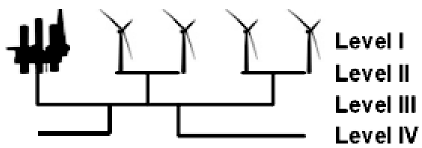

Figure 3: Offshore grid levels.

5.1 Collection grid known concept

The wind farm collection grid connects all the wind turbines in a farm to a common transformer (or converter) station. A wind farm with all turbines is usually planned in a single process, enabling good coordination of the activities. The system is constructed in one step and not changed significantly afterwards.

5.1.1 AC Collection Grids

The state of the art regarding collection grids is AC technology, and is applied to all existing wind farms. Far offshore wind farms with HVDC interconnection are a special challenge, since they are operated as an electrical island. Even though a lot of experience exists for the operation of AC grids, it is not possible to directly transfer all proven operation principles to offshore AC collection grids. Since no direct AC coupling to shore exists, the grid is an electrical island with its own frequency. This grid frequency is not linked to the rotational speed of electrical machines, and consequently it does not need to be the same as the main grid's frequency. Operational experience and knowledge on purely power converter based AC grids is limited. Control schemes for the operation of parallel inverters have been developed [8], but have so far been applied only in small scale. The feasibility for real life systems will hopefully soon be demonstrated at the Bard Offshore I wind farm.

5.1.2 DC Collection Grids

Long distance subsea power transmission has to be realized with HVDC. Wind turbines with permanent magnet generators directly rectify the generators output to DC. Considering both turbine output and transmission being DC, it is a logical consequence to question if a conversion to AC is needed.

This concept seems promising, avoiding unnecessary conversion steps, reactive power flows, the need for a third pole, and other known advantages of DC technology.

The feasibility of DC collection grids has been studied in literature and might gain importance in the future [9].

5.2 Offshore Cluster Grids

An offshore cluster grid connects several wind farms together. The future offshore clusters will be much larger than a single wind farm. The planning and operation of an offshore cluster grid can be challenging, since it will incorporate several wind farms of different operators and manufacturers that might use different types of collection grids.

5.2.1 AC Cluster Grids

Since the wind farm collection grids are usually realized with AC technology, it is convenient to realize a cluster grid also with AC. This choice is advantageous, since AC technology is mature, and a lot of components are available. Circuit breakers enable reliable and cost effective protection and sectioning schemes.

If the chosen frequency is set by the largest converter, control is easy but vulnerable if the reference unit fails. In larger systems the frequency should be determined by all units (like in a regular AC grid). Wind farms that have been constructed as stand-alone farms, creating their own frequency, will have to adapt to synchronizing with the other farms.

Wind farms with DC collection grid, and an HVDC converter station would need an extra converter to be able to connect to the AC cluster grid. The same applies for wind farms which use a different frequency.

5.2.2 DC Cluster Grids

In theory, both the internal wind farm collection grid, as well as the wind farm cluster grid could be realized using DC technology.

Wind farms with DC collection grids could connect more easily to such a cluster grid, possibly using the same converter, which was used for connection to shore via HVDC. Wind farms with AC collection grid also already have a HVDC converter, which might be used to connect to the cluster grid, rather than to a radial link to shore. All AC wind farms could also maintain their own frequency, avoiding the need for synchronization (but also loosing the benefits).

The operational experience with DC grids is still limited, which makes AC a more attractive technology for this task today. On the other hand, the construction of large offshore cluster is not happening today, so DC technology might improve and be ready, when it is needed.

In the future, when several DC cluster grids are interconnected with several HVDC lines, cluster grids and long distance transmission might merge to a single structure, dissolving the distinction between level III and IV.

6 ROADMAP

A question that naturally arises once the need for a supergrid has been established, is what the supergrid should look like. A plethora of topologies have been proposed. Czisch, who makes the remarkable claim that a supergrid would allow a 100% CO_2 free, affordable electricity supply for Europe in the near future [10], proposes a supergrid that is the outcome of a large-scale mathematical optimization (about 2.45 million constraints and 2.2 million control variables) [11]. Such a 'green field' approach would require perfect coordination between member states. Moreover, it fails to recognize that there are already a large number of offshore equipment installed, such as HVDC cables, offshore wind farms, and oil rigs. It is more realistic that the supergrid will develop in an organic way.

A second argument for the gradual development of the supergrid is that many technical challenges remain, before a meshed multi-terminal supergrid will become a reality. Moreover, multi-terminal operation of VSC HVDC is hitherto unproven. Between a first pilot project and a full-blown supergrid, many years will pass.

A first realistic intermediate scenario between point-to-point connections and a meshed multi-terminal HVDC grid could be a wind farm or CSP unit connected to different countries (Fig. 4).

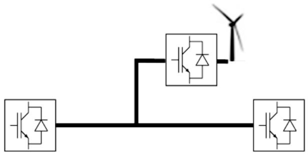

Figure 4: Three-terminal MTDC system.

A pilot project in the Baltic Sea is currently under study. It is studied whether the Kriegers Flak offshore wind development area in the Baltic Sea with a potential of 1800 MW could be connected to three countries Sweden, Denmark, and Germany. Recently, Sweden has withdrawn from the project.

A second example of an intermediate step is a system of two point-to-point connections between wind farms or CSP units and load centers that are interconnected at the generation side (Fig. 5).

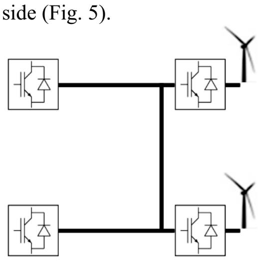

Figure 5: Four-terminal MTDC system.

When more generation such as wind farms, solar power and load centers are added, a three- or four-terminal HVDC system could gradually evolve into a meshed supergrid.

7 ONGOING INITIATIVES

A variety of initiatives on supergrids planning and development are launched in recent years. This section gives a brief overview, and covers the two projects "Friends of the Supergrid" and "Medgrid" in more detail. Both projects present an invited paper to the PSCC 2011 session on supergrids ([12], [13]). They exemplify the growing interest of industry in supergrids.

7.1 Friends of the Supergrid

The Friends of the Supergrid (FOSG) is an organization pushing for an offshore supergrid in the North Sea. Their definition of a supergrid is "an electricity transmission system, mainly based on direct current, designed to facilitate large-scale sustainable power generation in remote areas for transmission to centres of consumption, one of whose fundamental attributes will be the enhancement of the market in electricity." [12].

FOSG has proposed a roadmap in three steps to 2050. Phase I of the roadmap would link the UK with Belgium, Norway, and Germany. It recognizes the growing offshore wind projects in UK, Belgium and Germany, and balancing potential of the Norwegian hydro power.

FOSG believes that the first phase should be under development before 2020. This tight timing is deemed viable because the 'supernode' concept will be used. In terms of the terminology introduced in the previous chapter of this paper, a supernode can be regarded as several AC collection grids, connected to an AC cluster node. Several point-to-point HVDC links connect the node to shore. The supernode concept would circumvent technical problems related to multi-terminal DC grids, such as DC breakers, fast fault detection, etc. A major drawback of this concept, recognized by FOSG, is that a large number of AC/DC conversions stations are needed.

7.2 Medgrid

While FOSG concentrates on a North Sea supergrid, the Medgrid initiative focuses on the Mediterranean. Medgrid pursues a better interconnection of North Africa and Europe. Currently, only Spain and Morocco are linked. Proposed links are e.g. Algeria-spain or Tunisia-Italy. Medgrid committed to five main tasks:

- Design the Mediterranean grid master plan for 2020;
- Promote a regulatory framework for the exchanges of green electricity;
- Assess the benefits of investment in grid infrastructures;
- Develop technical and technological cooperation with South and East countries in the area of power grids;
- Promote advanced HVDC technologies for power transmission.

At this moment, no details on technical concepts are given, and the proposal is not backed by economical studies. However, Medgrid has established five working groups: master plan, economic studies, finance, regulation, technology. The time horizon of the Medgrid project is 2020, with a target of 5 GW of interconnections.

7.3 Various

The many ongoing activities and initiatives on supergrids indicate that the supergrid is seen as an important concept for the future. Among the many initiatives, we mention the following four:

- Twenties: one of the goals of the Twenties project's demo DCGRID is to analyze the technical feasibility of several topologies for future offshore DC networks, and to set out for each of them the technical challenges that need to be met before they can be operated in a safe way. (http://www.twenties-project.eu).
- The Desertec project proposes a supergrid to collect CSP from Africa and transmit it to Europe. The idea is based on studies from the German Aerospace Center [14], [15], [16].
- OffshoreGrid is a European project focusing on a regulatory framework for offshore grids

including technical, economical, policy, and regulatory aspects (www.offshoregrid.eu).

- The North Seas Countries' Offshore Grid Initiative is a framework for regional cooperation on possible future grid infrastructure developments in the North Seas. Deliverables are expected on: grid configuration and integration, market and regulatory issues, and planning and authorization procedures [17].

8 CONCLUSIONS

In future, an increase in offshore activities is expected. Offshore connections and wind farms, driven by trading and renewable energy agenda. An offshore grid infrastructure could serve the needs for trading and for connecting wind farms to shore. Furthermore, it would allow balancing renewable energy sources and create additional transmission capacity. Meshed multi-terminal VSC HVDC systems have been proposed as a solution to the technical requirements of a supergrid. However, we have shown that a large number of exciting technical challenges still remain, leading to the conclusion that a large meshed supergrid based on multi-terminal VSC HVDC will not be constructed at once. Rather, the meshed supergrid is the final step in a gradual process consisting of intermediate steps that can be based on a combination of AC and DC technologies, or on multi-terminal schemes that are not meshed. These configurations are better known than multi-terminal VSC HVDC. Their implementation could expedite the development of a European supergrid.

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The CIGRE B4 DC Grid Test System

Is not included due to copyright

Appendix C

Publications regarding Chapter 3

VII Improved Requirements for the Connection to the Low Voltage Grid

IX A novel control method for dispersed converters providing dynamic frequency response

IMPROVED REQUIREMENTS FOR THE CONNECTION TO THE LOW VOLTAGE GRID

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ABSTRACT

In Germany, about 80% of installed photovoltaic power is connected to the low voltage grid. During the summer of 2011, more than 10 GW actual feed-in is expected on a regular basis, indicating that low voltage power producers have gained significant system relevance. As a consequence they need to contribute to grid stabilisation, whereas former guidelines often demanded an immediate disconnection in case of disturbances. Meanwhile, this has become counter-productive and will be taken care of in new requirements for grid connection.

In this paper the risk of a major disturbance in case of an over frequency event is explained. The solutions which have been found for the high voltage and medium voltage levels are discussed. Differences to the low voltage grid are shown in order to explain the proposed modifications. Results of a simulation with a European Grid model are presented. Finally, measures for the incident and risk management as well as anticipatory precautions are proposed.

1 INTRODUCTION

The German Renewable Energy Act induced a rapid deployment of wind, biomass, and photovoltaic (PV) installations. The latter grew significantly in the last few years, as seen in **figure 1**. In 2010, an estimated 8 GW were added to the existing PV installations.

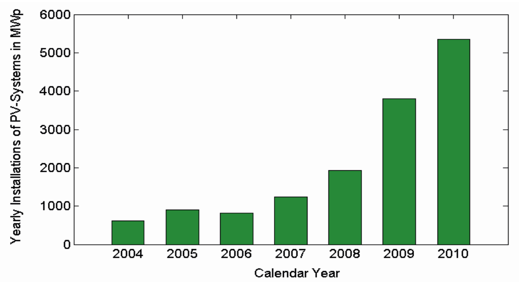

Fig. 1: New PV Installations in Germany, 2010 figures until October [1]

The majority of PV systems are connected to the low voltage grid. Together with other small generators e.g. microCHP, small hydro, and mini wind turbines these LV devices are gaining responsibility for ensuring grid stability. Especially PV may cause high power peaks at noon in the range of 10 GW (**figure 2**). A simultaneous loss of generation is a major threat to the safe operational range of the continental synchronous zone. This could occur as a result of the past technical guidelines for LV devices, which demanded a rather fast disconnection in case of grid disturbances.

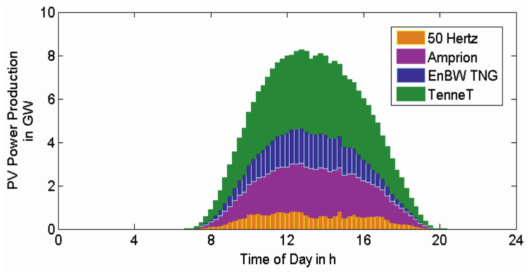

Fig. 2: German PV feed-in on 2010-09-06 [2]

This paper is outlined as follows: First, the theoretical background is described. The reason for inapt frequency dependent behaviour is not the PV system itself, but the chosen settings in several standards. Then, a simulation will clarify the effects on the grid frequency. Finally, possible measures to improve the situation are discussed.

2 RISK OF MAJOR SYSTEM DISTURBANCE

As frequency is a system-wide, global variable, the frequency response of LV generators is important for Transmission System Operators (TSO). In the past, LV generating units had been regarded as "noise generators" and were beyond the focus of TSOs. On the other hand, distribution system operators (DSO) are not responsible for frequency stability and they concentrated on a secure operation, i.e. staff safety with the objective to avoid an unintended islanding.

2.1 Norms & Standards

Some relevant standards for connection to the low voltage grid are the following:

DIN V VDE V 0126-1-1:2006-02

VDE 0126-1-1 demands a disconnection within 0.2 s if a frequency of ≥ 50.2 Hz is detected. A reconnection is allowed after 30s in the valid frequency range 47.5-50.2 Hz. Several other European countries use this standard as well.

DIN EN 50438:2008-08 & DIN CLC/TS 50549:2010-08

EN 50438 is a valid European Standard with an over frequency threshold of 51 Hz. Several national exemption rules are given in its annex such as VDE 0126 for Germany. TS 50549 is a technical standard, serving as a pre-norm, and covering generators larger than 16 A per phase.

IEEE 1547-2003

IEEE 1547 is used mainly in the United States for Distributed Energy Resources (DER). There is a fixed over frequency related disconnection threshold of 60.5 Hz and even worse an underfrequency trigger level of 59.3 Hz.

ENTSO-E Requirements for Grid Connection (Draft)

ENTSO-E published a working draft [3], which covers the size categories from A to D. A is the smallest class and relevant for LV generators from 400 W to 100 kW. A couple of requirements such as the active power frequency response (over frequency) are mandatory for class A, see **figure 4**.

2.2 System Behaviour of the Grid

The frequency response of the grid shows PID-characteristics. In the scope of this paper only the differential ($\Delta P \sim df/dt$) and proportional ($\Delta P \sim \Delta f$) part are relevant.

D-behaviour results from the rotating masses which provide inertia to the electrical system. P-behaviour comes from primary control as well as the self-regulation effect [4]. As a first approximation, the frequency response after a load step is of PT1-type. The overshooting comes from the fact that primary control needs up to 30s to ramp up in contrast to the self-regulation effect, which is instantaneously available.

2.3 Risk of non-linear Oscillations

In the case of a severe disturbance with several GW of sudden surplus power (loss of load as happened in 2003 or 2006) the frequency may rise considerably. This could lead to a simultaneous disconnection of low voltage generators. The frequency measurement precision is usually in the range of only a couple mHz, so that the threshold of +200 mHz will be detected everywhere more or less at the same time. Considering the time lag of 0,2 s and a rather high ROCOF, it can be assumed within the following model from the simulation section that all low voltage DERs will shut off.

30 s after returning into the allowed frequency range, LV-DER may reconnect and begin to feed-in again. A yo-yo effect could emerge as a general pattern.

The frequency development during a winter day is shown in **figure 3.** During ramp up and down periods, 1-h-block energy trading causes frequency variations of up to 100 mHz on a regular basis and sometimes more [5]. The security margin is largely spent during these few minutes at the full hour. A tripping of a large exporting HVDC line such as the Cross-Channel link at that time could be enough to hit the trigger level of +200 mHz.

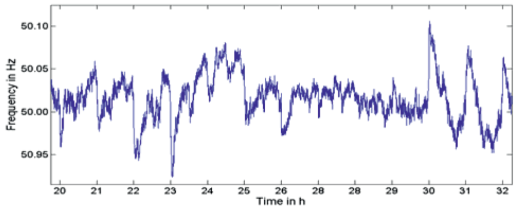

Fig. 3: Frequency Development during a 12 hour measurement period on 2010-12-22

2.4 Preferable Features of Low Voltage Connection Requirements regarding Frequency Response

According to VDN's TransmissionCode 2007 and BDEW's Technical Guideline "Generating Plants Connected to the Medium-Voltage Network" from 2008, an active power reduction is demanded with a gradient of 40% per Hz (droop of 5%). A higher gradient is proposed for the LV grid, as it shifts the influence of control power towards the high voltage grid during a major disturbance [6]. Furthermore, distribution system operators are faced with the situation to operate grid segments with gen-sets during maintenance or emergency supply. In order to avoid feeding back into the gen-set, all DERs are switched off by operating the distribution grid at increased frequency.

Therefore, a droop of s=1.6 % (K_f=125%/Hz) is proposed in this paper. At 51 Hz power production reaches a level of 0% P_{nom}. This may help to avoid hitting another disconnection threshold according to EN 50438, e.g. photovoltaics in Spain. It also leaves a frequency band for operating an islanded distribution grid segment above 51 Hz to ensure that all DERs are powered down.

In order to avoid any reconnection issues, no hysteresis is used when the frequency decreases back to normal after the disturbance. Power is ramped up according to the droop curve. Thus, the frequency is still a clear signal for the load situation of the synchronous zone. As an alterative for switchable units, which are not capable to modulate such as some micro CHP generators, randomised switching thresholds should be used.

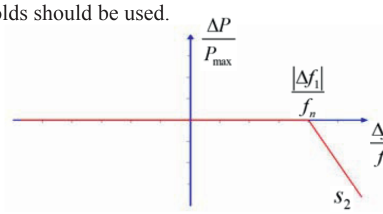

Fig. 4: Active Power Frequency Response (over frequency), R5.9 [3]

Currently, Forum Network Technology / Network Operation (FNN) is moderating the process of enhancing the German requirements for the connections to the low voltage grid. A first draft of this technical rule has been presented and a final version is expected in the first half of 2011.

3 SIMULATION OF FREQUENCY RESPONSE

In this section, the frequency development during a major over frequency event is presented. Two scenarios are shown, one with a sudden surplus power of 5 and another one with 10 GW. Italy's import volume was 7 GW on 2003-09-28.

Three simulations are run simultaneously:
1. PV shows no reaction to frequency excursions.
2. PV disconnects for 30 s if 50.2 Hz is exceeded.
3. Photovoltaic reduces production above 50.2 Hz reaching zero at 51.0 Hz (K_f=125% per Hertz).

3.1 Model Description

To evaluate the effect of PV-systems on the grid frequency stability a Simulink model of the continental part of the grid controlled by the European Network of Transmission System Operators for Electricity (ENTSO-E), called UCTE-grid (**figure 5**) has been devised. The model simplifies the grid as it neglects its spatial extent. For the purposes of this paper it is assumed that the frequency is the same at any point of the grid.

This UCTE frequency model is simplified, yet accurate enough to calculate the effect of power imbalances on the grid frequency. The model takes into account:
• system inertia
• self-regulation effect
• primary control
• load shedding
• pumped storage power plants
• photovoltaic feed-in

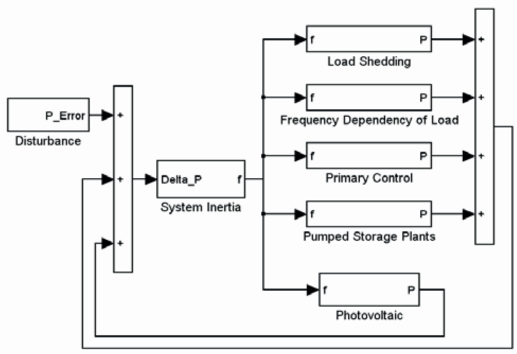

Fig. 5: The UCTE-Frequency Model

Secondary control is neglected, since it has little influence on the system within the first few seconds after a fault occurs. Reactive power is also neglected, since it does not directly influence the grid frequency. The model approximates the actual system behavior, as it is today in Europe. The system modeling is mostly based on [7] and [8]. A more detailed model description can be found in [9].

The model was used to simulate several kinds of system disturbances with different amounts of connected photovoltaic systems. The simulations presented within this paper will however focus on scenarios, where a significant share of the load is lost, leading to a rise of the grid frequency.

3.2 Simulation Results

The frequency development after a sudden loss of load at t=10s in the range of 5 GW is shown in **figure 6**. After ~2 s the 50.2 Hz level is hit and 10 GW of LV sources disconnect from the grid. The frequency decline is stabilised by the self-regulation effect, primary control and pumped storage. 30s later, LV generators begin to resume their feed-in, driving frequency again over the 50.2 Hz threshold.

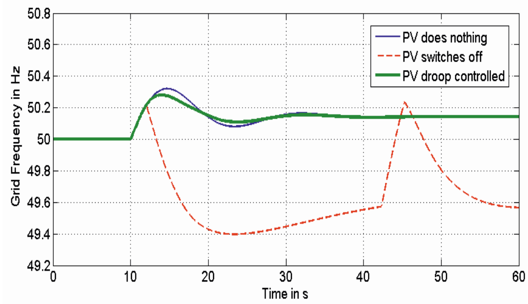

Fig. 6: 10 GW Photovoltaic with a Loss of Load of 5 GW

The scenario with 10 GW surplus power is displayed in **figure 7**. As the loss of load and the disconnecting PV power impulse equal each other, frequency stabilises temporarily around 50 Hz. Nevertheless, a yo-yo effect can be seen here as well.

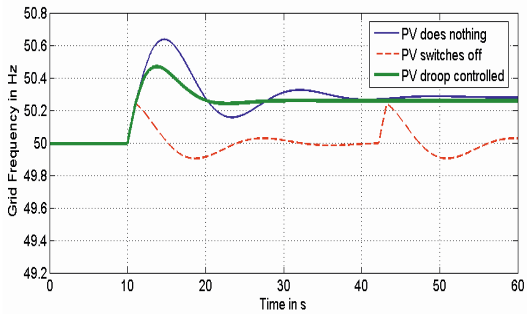

Fig. 7: 10 GW Photovoltaic with a Loss of Load of 10 GW

3.3 Discussion of the Results

Obviously, from a system point of view, the synchronous disconnection of LV generators is worse than no reaction at all. Droop controlled power reduction can be regarded as a method for a smooth stabilising strategy after the first disturbing impact at t=10s.

An important item is the reconnection issue. Even if not all PV inverters begin to resume with active power injection 30 s after frequency falls below 50.2 Hz, most of them do this within 30s-60s. MicroCHPs may need up to a couple of minutes for the restarting procedure. Finally, the automatically activated ramp up of LV power may outweigh the balancing power capacity available to TSOs.

4 DISCUSSION & OUTLOOK

As shown above, old requirements for grid connection of low voltage generators did not anticipate the system relevance of LV feedings. These unfitting connection standards enlarge the risk for major grid disturbances. Suitable countermeasures are discussed in the following section.

4.1 New Guidelines

Amended guidelines should come into effect as soon as possible. As frequency is a global variable within the grid (the effect of inter-area oscillations is neglected here), frequency response should be harmonised on all voltage levels vertically as well as horizontally between participating countries of synchronous zones.

4.2 Incident Management

In case of hitting the 50.2 Hz trigger level, a yo-yo effect as shown in the simulations above may occur. To stabilise this non linear oscillation in the GW range, two options are seen by the authors:
a) Stabilisation of grid frequency within 30s after the first LV shut-off above 50.2 Hz by load shedding until sunset.
b) Keep frequency low by quickly powering down dedicated plants so that the surge after reconnection will not hit the 50.2 Hz threshold again.

4.3 Risk Management

In order to defuse the existing legacy, incentives should be considered to update grid monitoring software in inverters. Modern PV-inverters are ready to update the firmware, but opening a splash proof cabinet to flash new code causes extra maintenance expenses. Monetary incentives could help to make already installed PV systems more grid friendly, please compare with SDLWindV. A simple approach is to randomise the over frequency setting in an evenly distributed interval of 50.2 – 51 Hz.

Synthetic Inertia
Hydro Québec's TransÉnergie already demands a compensation for the decrease of natural system inertia usally provided by synchronous machines. In the UK there are similar thoughts [10]. GE calls this feature of its wind turbines *WindINERTIA*, and Enercon has named it *Inertia Emulation*. Several research projects in industry and research institutions on emulating synchronous machine behaviour with inverters are in progress [11] [12] [13]. ENTSO-E drafted a requirement for power park modules (PPM) larger than 1 MW, see **figure 8**.

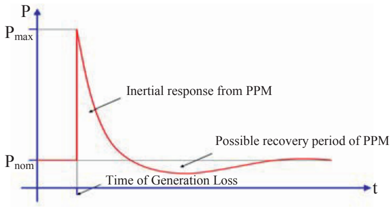

Fig. 8: Active Power Provision by Inertia, R7.10 [3]

Artificially enhanced self-regulation effect
The self-regulation effect is shrinking, as more and more drives are inverter powered and not directly connected to the grid. Frequency dependent power consumption may be introduced to fridges, air conditioning, electric vehicles, etc. They are able to deliver a new kind of ancillary service.

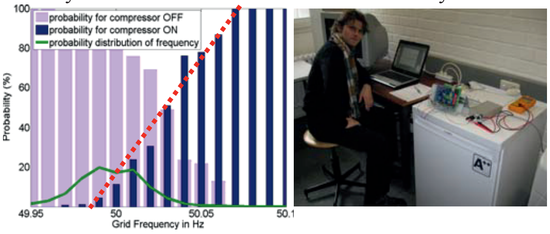

Fig. 9: Student project at TU Clausthal with a Smart Grid Device Controller, results from 32h data recording

Thus, the grid should get "harder" or at least avoid getting "softer", in order to miss the 50.2 Hz threshold. Another option for lowering the likelihood for action from over frequency protection is to popularise intra day trading with ¼-h-blocks which will minimise frequency excursions at the full hour and recover the security margin of 200 mHz intended for unplanned power imbalances.

5 SUMMARY

Existing grid codes for low voltage networks are endangering the system stability with advancing decentralisation of electric power production. Responsible stakeholders need to pay attention towards this issue. Three types of countermeasures have to be addressed: First, amended grid codes shall come into effect as soon as possible. Then, strategies for defusing existing installations have to be agreed on. Additionally, emergency plans in case of an over frequency incident shall be developed according to Policy 5 of ENTSO-E's Operational Handbook.

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ORIGINAL PAPER

A novel control method for dispersed converters providing dynamic frequency response

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Abstract Active power converters are flexible and highly dynamic. Many power converters, as battery charging devices, use only a small part of their technical capabilities. This paper develops a new control method that combines the primary converter function with grid frequency control. Doing this, the frequency stability can be influenced positively, using the power converters control potential, without penetrating its primary functions under normal power system conditions. In case of severe frequency deviations, priority is given to this grid support functionality, which can significantly improve the security of supply. If the converter's control algorithm does not take frequency stability aspects into consideration, the impact of thousands of these devices on the grid frequency stability will be negative. Electric and hybrid cars with battery storage and plug-in capabilities are used as an example for power conversion units. The impact of many cars, with the referred control method, on the UCTE (Union for the Co-ordination of Transmission of Electricity) grid frequency can be observed by simulations. Even a small percentage of electric cars can significantly influence the grid frequency after a power plant disconnection fault. No communication between network operator and converter is necessary for the basic grid supporting functions. Dispersed frequency support as suggested by the developed control method could be adopted as a requirement to future grid codes.

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Keywords Battery chargers · Control algorithm · Frequency control · Frequency stability · Road vehicle power systems

1 Introduction

Frequency stability in AC grids is important for the entire system, since electrical motors and generators can be damaged, if operated at an inappropriate frequency. As a reliable power quality is a main advantage of high-wage industrial countries, frequency deviations pose the risk of severe economic impacts.

Under normal operating conditions, the frequency is held within a narrow margin by the primary control, the rotating inertia of generators and motors and by the fact that the power consumption of motors depends on the frequency.

The primary control on the one hand is mainly provided by large thermal power generation units and can directly be influenced via the controllers of those power stations. The rotating inertia and the frequency dependency on the other hand are based on the physical properties of all electrical generators and motors connected to the grid. These important stability mechanisms cannot be influenced directly.

The number of loads and generation units, connected via power converters, is steadily increasing. Therefore, the number of classical electrical motors and generators will decrease, since they are partly replaced by modern converter-based systems. The transition from synchronous generators used in thermal power stations, to induction generators, often used in wind turbines, causes similar problems. This development will bring up new challenges regarding frequency stability.

The serious incidents affecting the UCTE-grid in 2003 [1] and 2006 [2] have shown that critical system conditions are worsened by converter systems with improperly designed control units. It is possible though, to design converter system controllers in a way to avoid these problems [3].

Different concepts were proposed, how dispersed generation units could take part in frequency support. Hughes et al. [4] proposes a controller for doubly fed induction generator based wind turbines, that can supply additional power drawn from the energy that is mechanically stored in the rotor. The impact of wind turbines and a possible frequency support functionality is discussed in Lalor et al. [5] regarding the Irish power system.

In Dynamic Demand [6], a refrigerator is dynamically controlled depending on the frequency to support frequency stability. This load is not converter-based and therefore not suitable for the developed control method, but the case indicates how flexible loads can take part in frequency control.

The feasibility of droop control in low voltage grids has been investigated in Engler and de Brabandere [7,8], though focusing on local phenomena like harmonics, short circuits, and synchronism to the grid frequency. Stabilization of the grid frequency via droop control based on a flywheel energy storage system with converter interface is described in Hamsic et al. [9].

Modern converter systems are highly dynamic. Most of the converter systems do not utilize all of their technical possibilities to fulfil their primary task. Battery charging devices create not more than a DC current and can therefore take other tasks at the same time. Electrical vehicles with large batteries and plug-in capability are a good example for converter systems, which could support frequency control. Technical aspects of plug-in vehicles and vehicle-to-grid capabilities have been addressed in literature like Kramer et al. [10]. The grid supporting capabilities of grid connected electric vehicles are especially important for micro grids [11], which lack regular primary and secondary control. Plug-in vehicles are used as an example in this study, but there are several other converter systems that are suitable for the developed control method.

It is possible to imitate the behaviour of an electrical generator or motor with a power converter, by implementing a suitable control algorithm. Power converter systems with a control emulating the behaviour of a real synchronous machine are called virtual synchronous machines [12]. These virtual synchronous machines can operate both as a motor or generator.

Compared with other conventional loads, synchronous motors show an advantageous behaviour regarding frequency stability. The advantage of virtual synchronous machines towards real electrical machines is that physical properties such as the momentum of inertia can be chosen freely and changed easily, by adapting the relevant parameters of the control algorithm. The parameter values can exceed the range which is feasible for actual electrical machines and it is possible not only to imitate real machines, but also to achieve more beneficial properties than those found in conventional loads.

Under extreme emergency conditions, when the reserve power mechanisms are not capable of balancing the production and consumption, shedding of loads or generation units is the last option to keep the grid frequency within admissible boundaries. Non-priority converters can shed themselves in order to prevent more important systems from being shed. Continuous shedding comprises advantages as compared to classical stepwise shedding. This approach can be highly beneficial in case of the unlikely event of a severe system disturbance, but it has not been sufficiently addressed up to now.

Owing to an increasing share of volatile generation units, the demand for power reserves might double until 2040 [13]. If classical electrical generators and motors are not replaced by converter systems with a standard control, but with frequency supporting controllers, the frequency stability can benefit significantly from this change. The aim of the developed control algorithm is to be simple and general, so it can be adapted to future grid codes. No communication between network operator and vehicle is necessary for the basic grid supporting functions. More sophisticated vehicle-to-grid applications like the ones described in Kempton and Tomic [14] and Guille and Gross [15] are compatible with this control method.

2 The UCTE frequency model

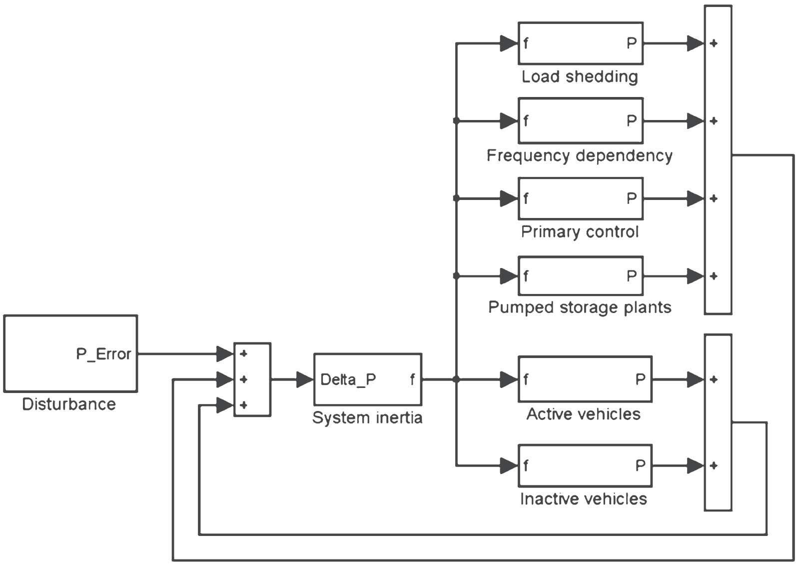
To be able to evaluate the effect of the developed control method on the grid frequency stability a Simulink model of the continental part of the grid controlled by the European Network of Transmission System Operators for Electricity (ENTSO-E) called UCTE-grid (Fig. 1) has been devised. The model simplifies the grid as it neglects its spatial extent. For the purposes of this paper, it is assumed that the frequency is the same at any point of the grid. For the implementation of load shedding, a fuzzy logic approach was used to compensate for the error created by this assumption.

This UCTE frequency model is simplified, yet accurate enough to calculate the effect of power imbalances on the grid frequency. The model takes into consideration:

- system inertia
- primary control
- frequency dependency of load
- load shedding
- pump storage power plants

Secondary control is neglected, since it has little influence on the system for the first few seconds in whom the fault occurs.

Fig. 1 The UCTE frequency model



Reactive power is also neglected, since it does not directly influence the grid frequency. The system modelling is mostly based on Haubrich and UCTE [16, 17].

The model approximates the actual system behaviour, like it is today in Europe. Two simulations are run simultaneously, while one represents the grid control as it is today, and one which also comprises converter systems, controlled with the developed method.

These converter systems are represented by an active and an inactive electric car fleet:

- Active: The vehicle is connected to the grid and either loading the battery or supplying power to the grid.
- Inactive: The vehicle is connected to the grid but no energy is being transferred (battery has been charged to demanded level).

Electric vehicles can either receive energy or feed energy back into the grid. To make use of this capability, the state of charge of the batteries must at any time be neither completely full nor empty.

The two simulations make it possible to observe and evaluate the effect of additional dispersed converter-based frequency control. The developed control method is in principle suitable for most kinds of converter systems, but is exemplified by electric cars.

The model was used to simulate several kinds of system disturbances considering different quantities of vehicles. The simulations presented within this paper will however focus on a reconstruction of the fatal incident in November 2006, when the UCTE-grid was split into three zones [2]. The two critical zones (Western Europe and North-Eastern Europe) were simulated and the results are presented in Sect. 5.

3 Mathematical equations of a synchronous motor

To develop a control algorithm based on a virtual synchronous motor, the power–frequency behaviour of the real synchronous motor has to be analyzed mathematically. It is sufficient for the development of a control algorithm to assume a machine with one pair of poles for each phase. Transient phenomena are ignored, so angular velocity of the grid voltages and the machine are equal at all times. All equations are linearised at the operation point ω_0 for the nominal angular velocity.

First the normalized angular velocity deviation is defined:

$$\omega' = \frac{\omega - \omega_0}{\omega_0} \tag{1}$$

The dependency of the torque on the angular velocity in steady state can be approximated with a Fourier sequence. Since the deviations of the angular velocity in electric grids are very small (0.4% under normal conditions) a linear approximation is sufficient. The quadratic term and all following can be neglected. The torque of a synchronous motor, which consists of a steady state and a dynamic part, can be written:

$$M(\omega) = M_0 \cdot \left(1 + K_{\mathrm{M}} \cdot \omega'\right) + L_0 \frac{\mathrm{d}\omega'}{\mathrm{dt}} \tag{2}$$

The parameter K_M represents the dependency of the torque on the angular velocity. L_0 is the angular momentum at ω_0. Now, the frequency dependency of the power consumption is calculated, since this is relevant for the power frequency control. The standard equation for mechanical power in rotating systems is

$$P = M \cdot \omega \tag{3}$$

(2) inserted into the power equation (3) results in:

$$P = M_0 \cdot \left(1 + K_M \cdot \omega'\right) \cdot \omega + L_0 \cdot \omega \cdot \frac{d\omega'}{dt} \tag{4}$$

The angular velocity can be expressed via the normalized angular velocity deviation:

$$\omega = \omega_0 \cdot \left(1 + \omega'\right) \tag{5}$$

(5) inserted into (4) leads to

$$P = M_0 \left(1 + K_M \cdot \omega'\right) \omega_0 \left(1 + \omega'\right) + L_0 \omega_0 \left(1 + \omega'\right) \frac{d\omega'}{dt} \tag{6}$$

Now the following approximations are introduced:

$$\omega'^2 \approx 0 \tag{7}$$

$$1 + \omega' \approx 1 \tag{8}$$

Using (7) and (8), (6) can be rewritten as:

$$P = M_0 \omega_0 \left(1 + (1 + K_M) \cdot \omega'\right) + L_0 \omega_0 \frac{d\omega'}{dt} \tag{9}$$

The nominal power is introduced

$$P_0 = M_0 \cdot \omega_0 \tag{10}$$

This leads to

$$P = P_0 + P_0 \cdot (1 + K_M) \cdot \omega' + P_0 \frac{L_0 \omega_0}{P_0} \frac{d\omega'}{dt} \tag{11}$$

Similar to the angular velocity, the normalized power deviation can be defined

$$P' = \frac{P - P_0}{P_0} \tag{12}$$

(11) can be written as

$$P' = (1 + K_M) \cdot \omega' + \frac{L_0 \omega_0}{P_0} \frac{d\omega'}{dt} \tag{13}$$

Now two new parameters are introduced:

$$K_P = 1 + K_M \tag{14}$$

$$T_A = \frac{L_0 \cdot \omega_0}{P_0 \cdot K_P} \tag{15}$$

This leads to:

$$P' = K_P \left(\omega' + T_A \frac{d\omega'}{dt}\right) \tag{16}$$

Equation (16) demonstrates that the synchronous motor shows the behaviour of an ideal PD controller. In Sect. 4, a control method for power converters is developed, which is based on this behaviour.

4 The control strategy

In this section, the active power control strategy of the converters is presented. The reactive power of the converter is set to zero as demanded by actual grid codes [18], which should be subject to further investigation. The structure of the control is shown in Fig. 2.

Every converter is operated at a specific value for the demanded power. For the short time frame addressed here, this demanded power can be seen as constant. On a longer time scale, it is of course not constant, but depends on the battery charging strategy. Possible vehicle-2-grid application like providing secondary frequency control power from electric vehicles can be combined with the developed control strategy. This promising future option is however beyond the scope of this article, which focuses on autonomous and automatic basic grid support. The developed control method is designed to allow vehicle-to-grid applications in addition to the basic grid support via influencing the demanded power. It is important although that any changes in the demanded power happen rather slowly to avoid interaction with the faster inner control loops.

Based on the demanded power, the steady state power order is calculated, which is a function of the frequency. This represents the proportional part of the control. Based on the frequency gradient, the differential part of the control is calculated and added, to determine the ideal power. This ideal power is then low pass filtered, to avoid unwanted reactions towards frequency noise. The filtered ideal power is finally limited, if it exceeds the rated power of the converter.

The developed control strategy works for loads, sources and also bidirectional storage units. In this paper, the example of loading electric vehicles is chosen, which appear as loads. All further explanations will focus on converter systems operated as loads.

4.1 Proportional part of the control

Under normal grid operation conditions, the active power should behave like a virtual synchronous motor. For more critical system states, different strategies are used and described in the following. First the stationary power order of the converter depending on the grid frequency is explained:

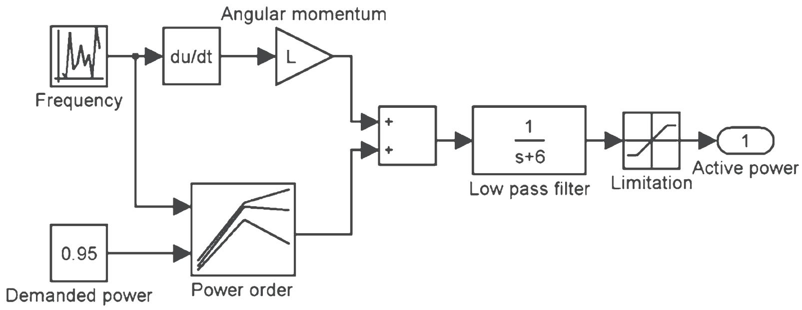


Fig. 2 The structure of the active power control

Seven important frequencies are given by the operational practices of the UCTE-grid [17]:

- $f1 = 47.5\,\text{Hz}$
- $f2 = 49.0\,\text{Hz}$
- $f3 = 49.8\,\text{Hz}$
- $f4 = 50.0\,\text{Hz}$
- $f5 = 50.2\,\text{Hz}$
- $f6 = 51.0\,\text{Hz}$
- $f7 = 52.5\,\text{Hz}$

$f4$ is the standard grid frequency; $f3$ and $f5$ are the limits of normal operational conditions. If the grid frequency lies outside the margin of 200 mHz above and beneath $f4$, the system operates under major fault conditions. The boundaries for the major fault conditions band are $f2 = 49.0$ and $f6 = 51.0\,\text{Hz}$. If that frequency band is abandoned, the system is in disaster conditions. The final borders of system operation are $f1$ and $f7$. If this frequency band is exceeded, the system will collapse.

The power order of the converter depending on the grid frequency is shown in Fig. 3. The different graphs show different demanded power values from maximal battery charging to zero power consumption. Each curve shows the frequency dependent power order of a converter with a specific value for the demanded power, while positive power order represents power consumption.

The upper curve shows a converter operated at the maximum demanded power of 95% of its rated power. The lowest curve shows the case of an inactive power converter, so the power order is zero under normal grid operating conditions.

Below $f2$ and above $f6$ all converters show the same behaviour, since their primary task is neglected in these cases. The details in Fig. 3 are described in the following subsections.

4.1.1 Normal operation

To achieve synchronous motor behaviour under normal system conditions, power consumption is supposed to rise linearly between $f3$ and $f5$. The maximal demanded power has to be limited at $f4$ to keep a margin to react towards rising frequency. The maximum value for the frequency dependency is determined by the size of that margin. A margin of 5% should be tolerable, so the demanded power of the converters is limited to 95% at $f4$. If the power order of a converter operated at the limit should reach 100% at $f5$, the frequency dependency is 26.3%/Hz. Regular loads only reach values up to 6%/Hz.

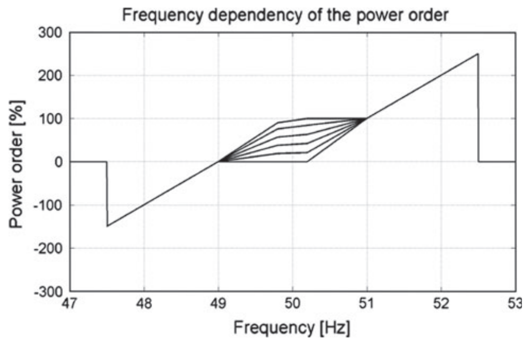


Fig. 3 The frequency dependency of the power order for loads

This margin should be feasible, since converters are usually not operated at their absolute limit. Owing to the short-term over-power capability of converters, it should be possible to implement this control without relevant draw backs. This of course will need to be verified, to make sure the frequency support task does not interfere with the primary task of the converter. If this assumption will be proven wrong, the margin and frequency dependency could be reduced. To achieve a frequency dependency of 6%/Hz, a margin of only 1.2% would be needed. The UCTE assumes the average frequency dependency to be only 1%/Hz [17], which could be achieved with a margin of 0.2%.

If the frequency dependency would be chosen zero, the converter could operate in the dead band between $f3$ and $f5$ without being under the influence of the grid frequency. Assuming a large part of the future load being converter-based, this is problematic. Within the dead band, the frequency would become more volatile due to the smaller share of load without a dead band.

If the required margin turns out to be problematic, the control method could also still be applied at times, when the converter operates at lower power than the absolute maximum. Battery loading strategies suggest that this will be the case for most part of the loading cycle.

The power variations have to be relative to the demanded power, not to rated power. Otherwise operation at low demanded power would be disturbed [18]. If the proportional part of the control would relate to the rated power, it could be in the same range as the demanded power (if that is at a low value). In this case, the control power would have significant influence on the primary task of the converter, which cannot be tolerated under normal operation conditions.

This leads to a converter operated at maximum capacity (95% at $f4$) reaching a power setting of 100% at $f5$, while a converter utilizing half its capacity (47.5% at $f4$) will reach a power setting of 50% at $f5$.

4.1.2 Major fault condition

If the frequency falls below $f3$, it is helpful to shed non-priority loads to save more important loads. Converter systems like battery charging devices can measure the frequency and shed themselves autonomously. Therefore, all converter loads should decrease their power consumption to reach minimal consumption at $f2$. If frequency rises above $f5$ consumption should increase for all converters, reaching 100% at $f6$. While a converter operated at the maximum capacity of 95% reaches 100% at $f5$, all converters reach 100% at $f6$ not depending on their demanded power setting.

Continuously shedding dispersed non-priority loads is an ideal system to handle large power imbalances. A PD controller without this feature would counteract frequency restoration after a massive frequency drop because it would try to stop the rising frequency (due to the differential part), disregarding the under frequency condition and such a problem occurred in de Haan and Visscher [19].

4.1.3 Disaster control

Below $f2$ and above $f6$ the entire power system is under disaster conditions. The primary task of the converters should therefore be neglected, and the control should switch to full grid support. The proportional part of the control should then exceed 100% to disable the differential part.

All converters have a power frequency relationship of 100%/Hz, not depending on the demanded power setting. At $f1$ power consumption reaches −150% and at $f7$ power consumption reaches 250% as well. A differential part of more than 150% would be needed, to make a difference. Therefore, converters will still not consume power at 48.0 Hz even if the frequency is rising slowly.

4.1.4 Collapsed grid

The final borders of system operation are $f1$ and $f7$. If this frequency band is exceeded, the system will collapse. The collapse above $f7$ will not happen in reality, since at that frequency generation units will disconnect from the grid, which will automatically restore the balance [16]. In these cases, the converters should as well be disconnected from the grid.

It is important although that if the collapsed grid is reactivated, converters do not switch on instantly. The black start of a collapsed grid is a difficult process. The converters should not interfere in the first seconds after a black start, but they should reconnect themselves slowly, and ramp up to their regular behaviour within minutes.

4.2 Differential part of the control

The differential part of the frequency control of a virtual synchronous machine is proportional to the angular momentum of the machine, which was chosen as a control parameter. Since the differential control part highly reacts towards high frequent noise, it is necessary to apply a low pass filter on the control, which was also identified in Lalor et al. [5].

The angular momentum should be as large as possible if it were not limited by the noise. A too large angular momentum would also have the disadvantage, that the reaction towards a fault would exceed the limitations of the power converter. This problem was identified in de Haan and Visscher [19].

The choice of the angular momentum highly depends on the low-pass noise filter chosen. If noise is reduced significantly by that filter, a larger angular momentum can be chosen, but the control will react slower due to that filter. The best compromise was found at an angular momentum of $4s^2$ times the rated power of the converter (with a filter time constant of 6s). This compromise is based on the simulations with different fault types and noise levels.

This angular momentum is by far larger than the corresponding value of real electrical machines and relates to a start up time constant of about 10 min. A real synchronous machine with such a large momentum would probably lose synchronism if the frequency changes, but this will not cause problems for virtual synchronous machines.

4.3 Low-pass noise filter

To reduce the reaction on the frequency noise, the control output needs to be filtered with a low pass filter. This filter should be a simple first-order low pass, to reduce oscillations when primary control and converter system trigger each other. Simulation results show that a filter time constant of 6 s is a good compromise, between control dynamics and noise resistance. Longer time constants are better suitable for reduced noise level, but the control will be slowed down. Since the main advantage of this dispersed converter-based control is the fact that it can react faster than the primary control, a large time constant of the filter is counterproductive.

In comparison with real electrical machines 6 s is a large time constant, which indicates that the robustness towards frequency noise of a virtual synchronous machine with the suggested control method would be rather good.

4.4 Power and energy limitations

The power (consumption or production) of the converter consists of the demanded power plus the filtered control power. The determined power value can exceed the power rating of the converter. Therefore a limitation is necessary, to protect the hardware from being overloaded. The same applies to storage systems that at some point are not capable of consuming or delivering power.

4.5 Converter systems operating as sources

If the control strategy is applied to power sources, the proportional part of the control has to be adapted, while the differential part and the low pass filter remain unchanged.

Converter systems, which are not operated as loads, but as generation units, also have to be frequency depended. The reaction towards frequency deviations has to be inverted, to support grid stability. If the frequency drops, consumption should decrease, while generation has to increase. This behaviour of the implemented control deviates from the behaviour of real synchronous generators.

The main part of the set of curves, which is in Fig. 3 between 100 and 0%, is now placed between −100 and 0%, since power consumption is considered positive. This will move the upper total boundary to +150% and the lower total boundary to −250%. The equivalent set of curves can be found in Fig. 6 in the Appendix.

4.6 Bidirectional converter systems

Bidirectional converter systems with energy storage can support the power system with consumption and production. The main part of the set of curves from Fig. 3 is therefore between −100% and +100% in this case. The total boundaries are at +250% and −250%. The equivalent set of curves can be found in Fig. 7 in the Appendix.

An inactive converter system (the middle curve) has a zero power order between $f3$ and $f5$. If the grid frequency drops below $f3$ power is produced, and if grid frequency rises above $f5$ power is consumed from the grid.

Bidirectional system offer the best grid support functionality and electric vehicles with battery would be perfectly suitable for this. However, the electrical distribution infrastructure was designed for unidirectional use, so a bidirectional power converter cannot be used without adaptations of the system. Smart substations or some other kind of control entity would be needed to guarantee that reversed power flows stay within permitted boundaries.

The recent developments in the smart grid field imply, that smart substation could be realized in the near future, to make bi-directional vehicle-to-grid (V2G) applications possible, which would also enable electric vehicles to connect as bidirectional systems, improving the grid support functions. This would also solve possible problems with conventional load shedding, since regions which supply power could be shed, if no flexible control is applied.

Owing to safety reasons, the connection type must instantly be switched to standard, if the communication between the converter system and the smart substation is lost; otherwise, a region that has been intentionally cut off could supply itself with dispersed generation and feeding converters.

Intelligent substations could also regulate the reactive power supply by the converter systems and support voltage stability.

4.7 Active and inactive converters

Converters connected to the grid can either be active or inactive. An active converter is either supplying or consuming power, while an inactive converter is operated at a preferred power rating of zero. An example for an inactive converter is an electric car, which is charged to the demanded level, and therefore not consuming any more power. The difference between an inactive converter and an active converter with a demanded power of zero is that for the inactive converter the differential part of the control is disabled.

Those inactive converters can supply a service in emergency situations, but they need to remain in standby and observe the grid frequency constantly, to detect these situations. If the grid frequency falls below $f3$, inactive converters (generation and storage) can activate themselves and then behave like regular active converters with a desired power of zero. The same applies if the frequency rises above $f5$ (storage and loads). If system conditions are stabilized and grid frequency comes back to the normal operation band, these activated converters can deactivate themselves again, but should do this slowly within minutes.

If smart substation are realized in the future, inactive converters should remain logged in, to allow a better overview over the available resources.

5 Simulation results

To show the improvement of frequency stability using the developed control method, the incident in 2006 leading to a blackout situation in parts of the UCTE-grid and described in Maas et al. [2] is reconstructed using the developed Simulink model. The simulation has been conducted with and without a fleet of electric cars that use the proposed control strategy.

5.1 Western part of the UCTE-grid

The fleet in the part of the network consists of 1,300,000 electric cars actively charging their batteries at the maximum rating of 95%. Already 100,000 vehicles are capable of influencing the grid frequency, but are not able to balance the power during such a heavy disturbance as in 2006. The number of vehicles in standby mode is not relevant in this case, since they could only increase power consumption. The rated power of the connection is chosen to be 11 kW, like it is usual for regular three phase connections in Germany.

The result shown in Fig. 4 confirms that the frequency stability can be improved. Without the reaction of electric cars, the frequency drops quickly down to 49 Hz, which triggers load shedding. About 15 GW loads are shed, which stops the frequency from falling even lower and creates a small power surplus. This, in combination with the primary reserve, leads to a slowly rising frequency.

The red dashed curve shows the simulation with electric vehicles. Those react quickly to the frequency drop due to the differential part of the control. Therefore the frequency decreases much slower, and stays above 49 Hz. Only about 3 GW of loads are shed in this simulation, of which half are pump storage power plants. After 24 s of the disturbance, the frequency is lower than it is without the electric cars. This seems contradictory, but it is purely based on the fact, that fewer loads were shed.

During the first minute after fault, the simulation without virtual synchronous machines is close to the real frequency behaviour during the fault in Europe in 2006. The system behaviour after the first minute cannot be reproduced with the developed model, due to its limitation on primary reserve and system inertia.

If the power rating is chosen higher, a smaller number of vehicles will lead to similar results. If the vehicles are connected with bidirectional connections, enabling them to feed power into the grid, also inactive vehicles could support the grid, and actively changing vehicles could support the grid more effectively. Similar results can be achieved with a smaller number of vehicles with bidirectional connection.

5.2 North-eastern part of the UCTE-grid

In Fig. 5 the simulation results for the north-eastern part of the grid are plotted. In this part of the network, a large power surplus endangered the system after splitting off from the rest of Europe. The solid black curve shows how strongly the frequency oscillates right after the grid is split. If 500,000 inactive electric cars placed within the north-eastern region react to frequency changes, activate themselves, and consume power to absorb the surplus until the primary reserve is activated, the oscillations can be avoided.

About 1 min after the disturbance, the frequencies are almost identical, with and without electric vehicles. This indicates, that the contribution of the converters is only of short duration, basically bridging the time gap between disturbance and primary reserve activation.

6 Summary

A new control method for power converters in electrical grids is developed, which is based on the principle of a virtual synchronous machine. The developed control method is suitable for converter loads, storage and generation and can significantly improve frequency stability. Since a lot of power converters like battery charging devices use only a small part of their technical potential, the unused capacities can be utilized to influence the power balance of the entire grid. The additional control power can support frequency stability even before the primary reserve is activated.

Converter systems without flexibility, like the drives of an industrial robot, cannot take part in grid stabilization, since their active power flows are already determined at any moment by their primary task.

The chosen control parameters like frequency dependency and virtual angular momentum are much larger than the parameters of a real synchronous machine. This positively influences the frequency stability of the power system.

In case of severe frequency deviations, priority is given to the frequency support functionality of the converter. While at 50.0 Hz the control only fulfils the primary task of the converter, it changes more and more in direction of full grid support, the more and faster the frequency changes. This can help in keeping the power balance in case of large power shortages that exceed the capability of the primary reserves. The frequency can be stabilized until the secondary control is activated and therefore load shedding can be avoided, which significantly improves the overall security of supply.

The control can be applied to converter system representing loads, sources and even bidirectional storage units, which can reverse power flow to support the grid under severe disturbance.

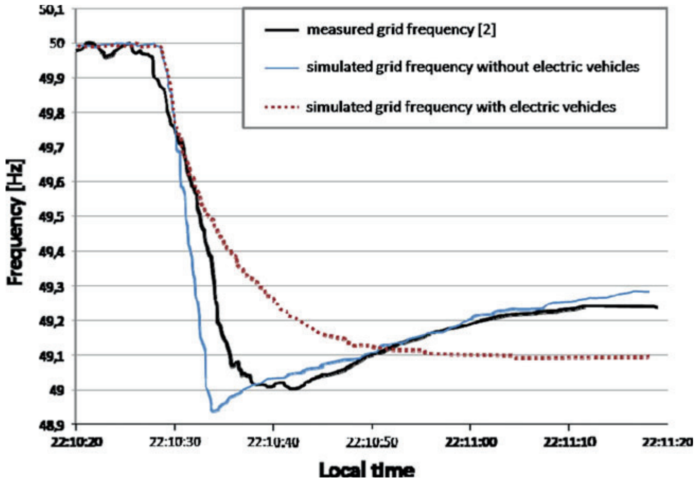


Fig. 4 Simulated and measured grid frequency in western grid part 2006 [2]

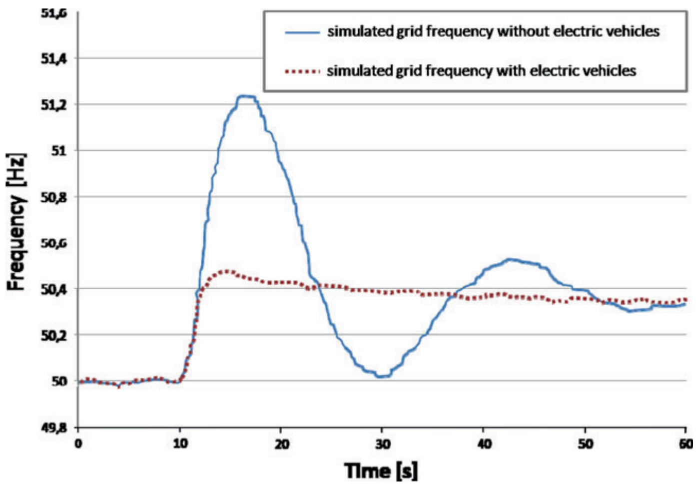


Fig. 5 The simulated grid frequency in the north eastern grid part 2006

Not only active power converters are taken into account by this control method. Electric vehicles with a fully charged battery are inactive, but can still engage in frequency response under emergency conditions if necessary.

An advantage of this control algorithm is its autonomous behaviour. No communication between network operator and vehicle is necessary for the basic grid supporting functions.

The differential part of the developed control algorithm is also an important addition to classical droop-based controllers. Droop control only reacts, if the frequency already has changed, while the differential control reacts earlier and tries to prevent a frequency change.

The simulation results[1] indicate that a small percentage of vehicles equipped with the developed control strategy can significantly influence the grid frequency in Europe in a positive way.

[1] The control method was developed and the simulation was conducted as part of the diploma thesis by T. K. Vrana, "Analysis and Definition of Technical Specifications of Dispersed Inverter-Based Energy Conversion Units in Distribution Grids" (2008).

Appendix

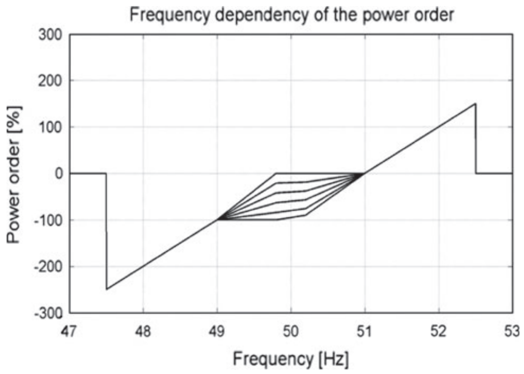


Fig. 6 The frequency dependency of the power order for generation units

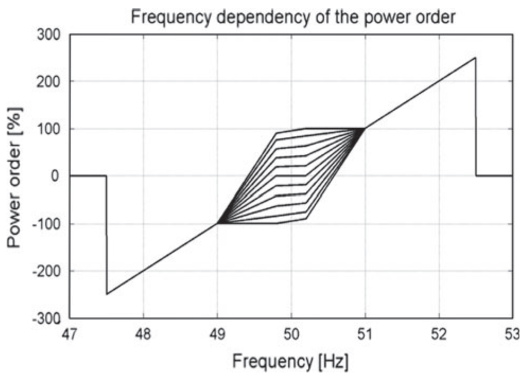


Fig. 7 The frequency dependency of the power order for bidirectional converter systems

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Appendix D

Publications regarding Chapter 4

XI A Classification of DC Node Voltage Control Methods for HVDC Grids

XII Active Power Control with Undead-Band Voltage & Frequency Droop for HVDC Converters in Large Meshed DC Grids

XIV Dynamic Active Power Control with Improved Undead-Band Droop for HVDC Grids

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Review

A classification of DC node voltage control methods for HVDC grids

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A B S T R A C T

In a DC grid, contingencies such as converter outages give rise to a current imbalance that is reflected in the DC node voltages in the grid. This imbalance has to be accounted for by changing the currents flowing in and out of the DC system. These DC node voltages can be directly influenced by controlling the DC current of the HVDC converter at that node. Different control strategies can be applied to balance the currents in a DC grid after a contingency.

In this paper, the different converter control strategies are introduced systematically, thereby aiming to provide a framework for classifying the different converter control strategies available in literature. It is discussed how all converter control strategies theoretically can be regarded as limiting cases of a voltage droop control. It is also explained how the different converter control concepts can be combined, leading to more advanced converter control schemes such as voltage margin control, dead-band droop control and undead-band droop control.

Based on the introduced converter control strategies, different grid control strategies are introduced and classified. The application of the advanced converter control strategies results in advanced grid control strategies and the advantages of those are discussed.

Contents

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1. Introduction

The academic community as well as transmission grid operators and manufacturers have gained a strong interest in meshed HVDC grids [1]. No system of this kind has ever been built, and the entire subject is a future vision and still subject to basic research. The drivers for this development are both technology push and demand pull. Improved semiconductors, increasing power ratings for AC/DC converters and the first prototypes of DC breakers put HVDC grids within reach. The widespread renewable energy development demands new solutions for electric power transmission, especially when it comes to remote offshore wind farms.

The first place where meshed HVDC grids could emerge is the North Sea [2]. In this region massive wind farm construction has started and is planned for the coming decades, and many of these farms will be far away from shore. These remote offshore wind farms require HVDC connections, since long distance subsea transmission is not suitable for AC. The large number of planned wind farms and HVDC links within the North Sea indicates that an integrated grid-based system solution will offer significant benefits (compared to a one cable per farm solution) [3–6]. The countries around the North Sea have agreed to build the North Sea Super Grid (NSSG) under the North Seas Countries Offshore Grid Initiative [7].

A second future application could be the European Super Grid. Although still more a vision than a project, the super grid concept has gained remarkable attention during the last years, since it could be of high relevance for the desired pan-European electricity market. A super grid, interconnecting various regions with their own generation mixes and load patterns, would be beneficial for a large-scale renewable energy development. A HVDC based electricity grid spanning over entire Europe is envisioned [8], with possible extensions to northern Africa [9].

Although many similarities exist, the working principles and operational characteristics of such a DC grid are different from the ones in AC systems. The main differences result from the fact that no reactive current, reactive power and phase angle exist. Therefore the DC node voltages are the most important measure, which define the system state and the power flow. Since DC voltages are directly linked with DC currents, it makes sense to refer to a current balance in the DC system rather than a power balance as in an AC system.

This article aims at classifying the different node voltage control methods, which have been proposed in literature in the recent years. The control objectives and requirements and the steady state working conditions of DC node voltage control are discussed, while the actual control implementation is not covered. Slower control actions, like power rescheduling are not treated in this article. Mathematically, this means that no set-point changes are considered for DC voltage control. The focus is purely on DC voltage control as a means of active power balancing, similar to primary frequency control in AC systems.

2. HVDC converter control requirements for large DC grids

The requirements for HVDC converters connected to large DC grids are substantially different from the state of the art control requirements for two-terminal HVDC schemes. Additional challenges arise when small AC islands like offshore wind farms are connected. The main requirements of large DC grids are explained in this section.

2.1. High reliability

For all existing point-to-point HVDC systems, single component faults can degrade system performance and even lead to system shut down. A meshed HVDC grid, possibly integrating many gigawatts of generation units, has to be much more reliable, since its performance is essential for the connected AC grids.

2.2. Integration of electrical islands

Requirements of the HVDC converter control depend on what type of AC system they are connected to. It is expected that onshore power systems are more suited to contribute to balancing control, when compared to offshore wind farms. The wind farms can be considered to be electrical island with a large volatile power source. Hence, the offshore wind farm converters have much less flexibility with respect to controlling the power injection to the DC grid, as they need to deliver the wind power to the DC grid, in real time. Therefore, fewer possibilities exist for the wind farms to participate in the aforementioned balancing control, which has to be performed mainly by the onshore stations, which are connected to larger AC systems.

2.3. Plug and play

The principle of “plug and play” is important, meaning the controls have to be defined in a general way. This takes into account the specifics of the DC grid dynamics, whilst assuring the interoperability of different types of converters. Meanwhile, these general control principles should include control specifics that can be different for each converter in a multi-vendor set-up, while not compromising the interoperability and overall functionality of the grid. This means that the general control principles of the first converters installed should be controlled in such a way, that its control outline would not be subject to change in the case where many more converters are added to the same DC system in the future.

2.4. Autonomous converter control

A loss of communication is always a possible threat. Therefore all converters must be able to survive with local measurements only. This is similar to onshore AC power systems, where primary frequency control ensures reliable system operation without the need for communication.

2.5. AC grid integration

When the DC grid interconnects different non-synchronized zones, it is possible to share the primary frequency reserves of these different zones by implementing an AC frequency control.

If a significant part of the power that is supplied to the AC systems is coming from the DC grid, it is beneficial if the HVDC converters take part in the AC frequency control. In [10], a control scheme was presented to combine the aforementioned DC voltage control with an AC frequency control.

3. Basic control principles

All methods described in this article utilise local DC voltage measurements in order not to fully rely on external data for the control to work. However, the overall performance might be improved by using a common voltage signal for feedback, as proposed in [11].

In this article, positive current and power is defined as flowing out of the DC grid, which is coherent with the physical definitions of voltage, current and power. In power systems, a reverse convention is often in use, which might be more intuitive as production being positive and loads being negative. Given the definition on the DC side and the convention on the AC side, an HVDC converter in inverter mode has positive current and power and in rectifier mode negative. The direction reference is therefore consistently defined for both the AC and the DC side. This leads to regular AC frequency droop curves having a negative slope, and DC voltage droop curves (e.g. Fig. 2, Section 4) having a positive slope.

The control of the DC voltage shows a lot of similarities with frequency control in an AC power system. Whenever a deficit occurs in the current that flows in/out the DC grid, the voltage at the different nodes will immediately react to this change as a result of the capacitors and cable capacitance discharging or charging. This current deficit can occur, for example when a converter faces an outage. If the converter was exporting to the AC system, the outage will cause a current surplus leading to a voltage increase. On the contrary, if the converter was importing into the DC grid, the converter outage causes a current shortage leading to a voltage decrease. DC voltage can therefore be taken as a balance indicator, similar to AC frequency in AC power systems.

In AC systems however, the frequency is the same throughout the entire system. The active power flow on a line is observed through the phase angle. In DC systems, DC voltage is both influenced by the global balance as well as by the currents on the lines. Therefore DC voltage is not a true global measure and it is therefore more challenging to use the DC voltage as a reference for balancing control. Despite these difficulties in terms of control, the DC voltage still appears to be the best indicator for stable DC grid operation.

Based on the described behaviour, it is clear that the current balance has to be restored as soon as possible in order to keep the voltage from falling or rising. All control structures discussed further on in this article rely on the fact that the deviation with the controlled DC voltage (local measurement at each DC bus) is determined and corrected for by the control action, which come down to restoring the current balance.

Assuming a lossless system, all node voltages would be identical and the current balance can be directly rewritten as a power balance. In a real system, DC line losses will add to the power balance equation and cause a mismatch between imported and exported power. Still, the general phenomena are the same: A change in the power balance will cause the DC voltage to deviate.

There are two basic principles how DC voltage can be controlled: Current based control and power based control [12,13]. It is important to mention, that both current based control and power based control behave identically at the operating point. The larger the DC voltage deviates from the reference value, the larger the differences between power and current based control become.

3.1. Current based control

In a current-based control scheme, the relationship to be used to control the DC voltage is an *I*–*V* characteristic [14,15]. The main advantage of a voltage–current control characteristic is that it reflects linear control behaviour in the sense that a voltage deviation will result in an equivalent current deviation. As the voltage is linked with charging or discharging the capacitive DC system, the control is linear and is the same for all voltage deviations from the reference value. The voltage power relation is consequently non-linear (parabolic).

Current based control can be directly linked with the DC network dynamics: The charging of the capacitances in the DC network relies on a linear current voltage relation, which has the physical unit Ω. This makes current based control somehow intuitive from a physical perspective as it has the same physical units as the DC line impedance.

3.2. Power based control

As an alternative to the current based control, the DC voltage control can be expressed in terms of active power, as discussed in [16–18]. The power voltage relation is here linear. Contrary to current based control, power based control shows non-linear (hyperbolic) control behaviour. One should take into account the fact that DC voltage control therefore is non-linear.

Power based control has the advantage that it is more intuitive from a power system perspective, where the focus often is on transmitted power. It is also somehow similar to power frequency control in AC systems. The power voltage relation would have a physical unit of 1/A or Ω/V, which does not have a direct intuitive physical meaning.

Power based control can easily be integrated with the existing vector control schemes, which is well suited to be used with the standard *dq*-current controllers used in VSC HVDC systems. As discussed in [19], it is also possible to use the current based control to create an AC current reference.

3.3. Converter and system limits

There are several limits for HVDC converter control. The 3 most important are briefly described here and shown in Fig. 1. The values for the limits in the figure are chosen for good graphic illustrations and do not represent realistic HVDC converter limitations.

- *DC voltage limits:* the DC voltage has an upper and a lower limit. The upper limit is determined by the insulation of the switching components. The lower limit is more complex as it is based on a limitation of the modulation index, and it also depends on the converter topology and the converter control implementation. These details are out of scope of this article.
- *Power limits:* the active power has an upper limit. This power limit is caused by the semiconductor current limit, which limits the AC current and consequently the power (assuming a constant AC voltage). The power limit appears as a hyperbolic curve in the *IV*-curves, and as a straight vertical line in the *PV*-curves.
- *DC current limits:* the DC current has an upper limit, based on the current rating on the connected DC components. This appears as a straight vertical line in the *IV*-curves and as a straight line towards the axes intersection in the *PV*-curves. As the limits depend on the connected DC equipment, there is no general answer whether these limits can be reached: The lower voltage limit might be reached before the current limit is hit.

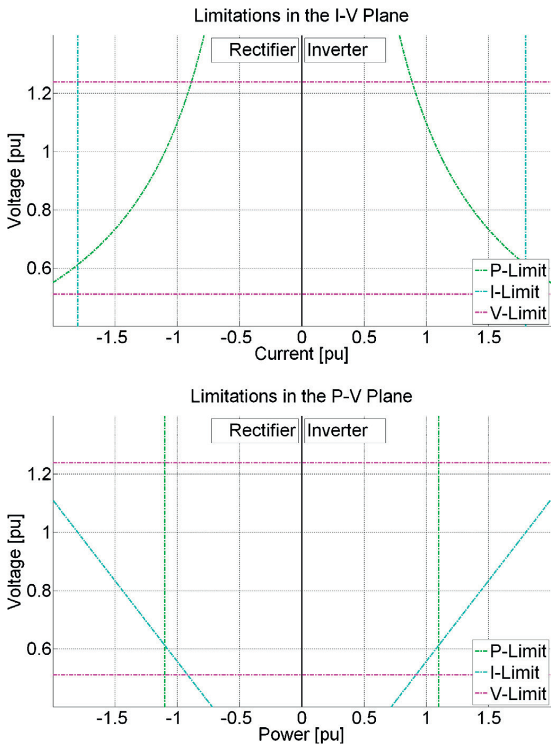

Fig. 1. Converter and system limits.

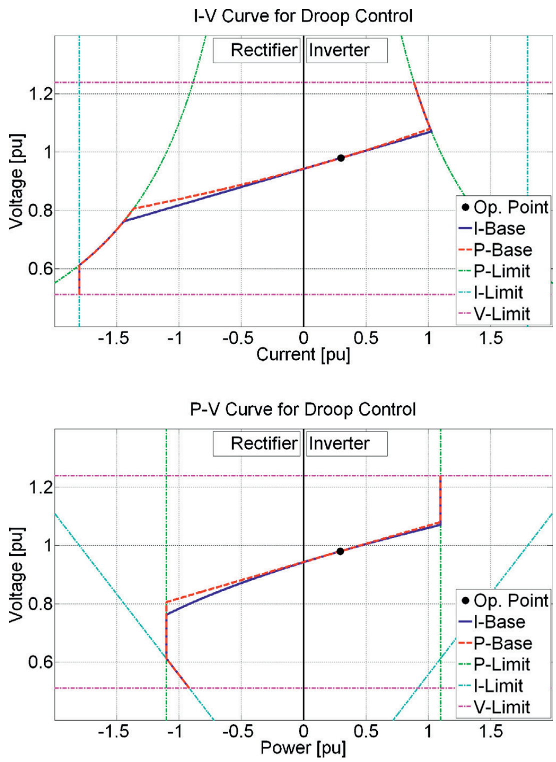

Fig. 2. *I–V* curve and *P–V* curve for droop control.

4. Basic converter control strategies

In the previous section, emphasis has been put on how a converter can control the DC voltage control and the distinction that can be made based on the *P–V* or *I–V* relationship. In this section, it will be discussed how different control schemes can be approached as a generalised case of a voltage droop control. The discussion holds both for an *I–V* or a *P–V* based droop.

The control is complicated by the fact that the voltage in the DC grid varies as a result of the DC grid power flow. In order to obtain a certain power flow, the voltage set points have to be different for all converters and should reflect the steady-state power flow solution of the DC network.

The explanation provided in this section reflects the mathematical representation of the control objective in terms of droop characteristics. The actual implementation, however, does not necessarily rely on the proportional droop controller, as discussed below. The term "basic strategies" refers to consistent control strategies, which do not depend on the operating point. The control strategies have only a single parameter, which is the droop value or control gain. The control is therefore linear. The advanced control schemes in Section 5 can be seen as a combination of the three control types discussed in this section.

4.1. Voltage droop control (positive droop constant)

Voltage droop control creates a proportional relationship between the voltage and the control base (current or power) and is shown in Fig. 2.

The droop constant is called *k*. The control base is indicated by the subscript "*I*" or "*P*". The subscript "ref" indicating the voltage, current and power set-points, with the natural relationship: $P_{ref} = V_{ref} \cdot I_{ref}$. The voltage, current and power deviations are defined as: $\Delta V = V - V_{ref}$ and $\Delta I = I - I_{ref}$ and $\Delta P = P - P_{ref}$.

The *I–V* droop relation can be written as:

$$\Delta I_I = \frac{1}{k_I}\Delta V \tag{1}$$

Rewriting (1) in terms of active power yields the corresponding power equation which is parabolic:

$$\Delta P_I = \left(\frac{V_{ref}}{k_I} + \frac{P_{ref}}{V_{ref}}\right)\Delta V + \frac{1}{k_1}\Delta V^2 \tag{2}$$

The expression for the *P–V* droop relation is similar to (1), namely:

$$\Delta P_P = \frac{1}{k_P}\Delta V \tag{3}$$

Rewriting (3) in terms of current yields the corresponding current equation which is hyperbolic:

$$\Delta I_P = \left(\frac{1}{k_P} - I_{ref}\right)\frac{\Delta V}{\Delta V + V_{ref}} \tag{4}$$

The slope of the *I–V* or *P–V* characteristic is determined by the droop value, which is the inverse of the proportional controller gain. The droop value *k* in these equations stems with the slope of the characteristics in Fig. 1, and is the inverse of the proportional controller gain used in the actual implementation. The stability of the droop controller depends on the droop value and the actual implementation. If well designed, the voltage droop control leads to a stable operation. When a contingency occurs, the droop

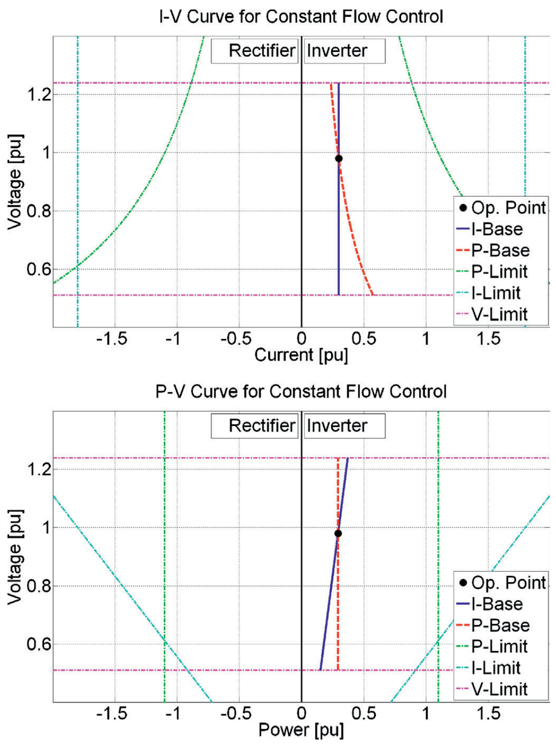

Fig. 3. *I–V* curve and *P–V* curve for constant flow control.

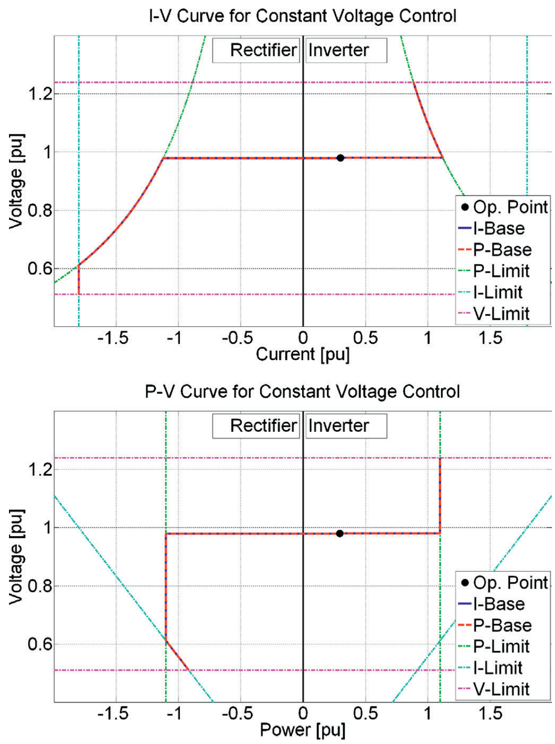

Fig. 4. *I–V* curve and *P–V* curve for constant voltage control.

control is characterised by a steady-state deviation from the voltage reference as a result of the proportional control action.

4.2. *Constant flow control (infinite droop constant)*

Constant flow control means constant current control and constant power control (depending on the control base) and can respectively be represented as a vertical line segment in the *I–V* and *P–V* plane. Mathematically, the constant flow control can be expressed as a limiting case of the aforementioned voltage droop, with a droop constant equal to infinity, thereby not changing the current/power flow whenever the DC voltage changes. The converter will, at all cost try to maintain the current/power injection constant, irrespective of the value of the DC voltage at its DC bus.

Fig. 3 shows the characteristic curves for both constant flow control types in the *P–V* and *I–V* plane. Constant current control leads to a linear behaviour in the *P–V* plane. Constant power control leads to hyperbolic behaviour in the *I–V* plane.

In reality, however, constant flow control is implemented using a PI-controller to keep the current/power equal to its reference value. This is due to dynamic reasons, but theoretically, this comes down to the limiting case of an infinity droop value.

4.3. *Constant voltage control (zero droop constant)*

Constant voltage control can be represented as a horizontal curve in the *I–V* or *P–V* plane (Fig. 4). The DC voltage control can be regarded as the limiting case for which the droop constant goes to zero. From Eqs. (1) and (3), it is clear that the converter in this case controls the voltage limit to its reference value. In Fig. 4 no distinction between current and power based control is shown, since the curves are identical. A converter with this type of control is often referred to as a DC slack bus.

This control modus relates to a proportional control gain of infinity. This of course is unrealistic and will lead to instability. Constant voltage control is therefore in reality not realised with an infinite gain, but with a PI controller. In theoretic steady state the outcome is the same, but due to dynamic reasons, the infinite control gain is not viable.

5. Advanced converter control strategies

In this section control methods are covered, that cannot be described by a single control parameter. They are therefore non-linear, or to be more precise piecewise-linear. The actual control behaviour depends on the operating point, thereby making a distinction between normal and disturbed operation. The advanced converter control strategies behaviour changes when large disturbances occur.

5.1. *Voltage margin control*

Voltage margin control has first been proposed for DC networks in [20] and later been applied and developed further in [21,22]. It is a combination of constant current/power control and constant voltage control. A converter with voltage margin control normally operates in constant current/power control modus (as long as the voltage is within the normal operation voltage margin). If the voltage deviation reaches the limit of the voltage margin, the converter controller switches to constant voltage control, clamping the voltage at the margin limit to prevent further voltage deviation. This is shown in Fig. 5.

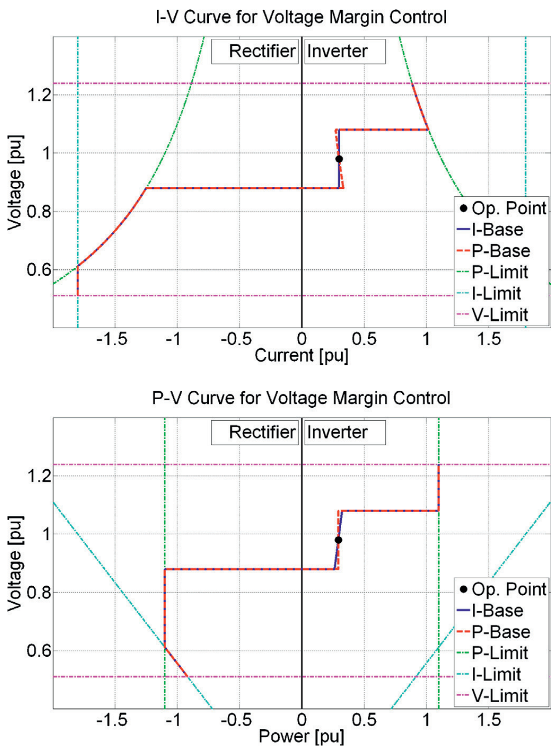

Fig. 5. *I–V* curve and *P–V* curve for voltage margin control.

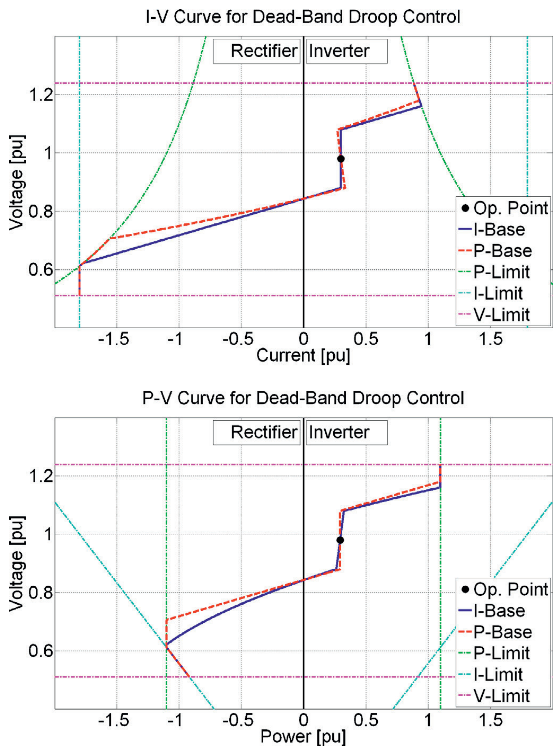

Fig. 6. *I–V* curve and *P–V* curve for dead-band droop control.

5.2. Dead-band droop control

Another advanced control strategy is droop control with an additional dead-band [23]. Just like with voltage margin control, the converter operates at constant current/power control modus as long as the voltage is within the normal operation band or margin. If the voltage deviates to the limit of the dead-band, the controller switches to droop control. Voltage margin control can be seen as the limiting case of dead-band droop control with a zero droop constant. This is shown in Fig. 6.

5.3. Undead-band droop control

Another approach to DC voltage control, the so-called undead-band droop control, has been proposed in [24] and developed further in [25]. The control is fully based on voltage droop, but distinguishes between normal and disturbed operation by defining different droop constants for these two operation regimes. It offers the possibility to optimise the droop constants and the overall control separately for normal and disturbed operation. This is shown in Fig. 7. A similar concept has been proposed in [26].

The definition of undead-band droop control is most general, and all the other mentioned control methods can in fact be considered as specific examples of parameter sets of undead-band droop control. For example, dead-band droop control can be seen as the limiting case of undead-band droop control with an infinite droop constant (constant current/power) under normal operation. Similarly, voltage margin control can be seen as the limiting case of undead-band droop control with an infinite droop constant under normal operation (constant current/power) and a zero droop constant under disturbed operation (constant voltage). Regular droop control can be seen as the limiting case of undead-band droop control with the same droop constant in both operation modes.

Also other strategies, not mentioned in this article, can be perceived accordingly. As a compliment to dead-band droop control, a zero droop constant under normal operation (constant voltage) can be combined with droop control under disturbed operation. Unlike a dead-band, where the converter does not react on voltage changes, this scheme keeps the voltage constant under normal operation [27]. Another possible variation is a controller with droop control under normal operation and with zero droop (constant voltage) under disturbed operation [28].

6. Basic grid control strategies

In general, the DC voltage can be controlled to its reference value at one centralised voltage-controlling converter or by using a distributed control approach. The basic grid control strategies discussed in this section are based on the basic converter control strategies from section 4.

6.1. Centralised voltage control

One converter has a droop value of zero, controlling a constant DC voltage at its bus (Section 4.3), thereby acting as a DC slack bus. The other converters have a droop value of infinity (Section 4.2) and control their current/power to the setpoint. The control concept is similar to the normal operation of a point-to-point VSC HVDC system.

Centralised voltage control gives rise to a well-defined operating point, since all but one converters operate at their current/power set-points. This strategy can hold for quite large networks under

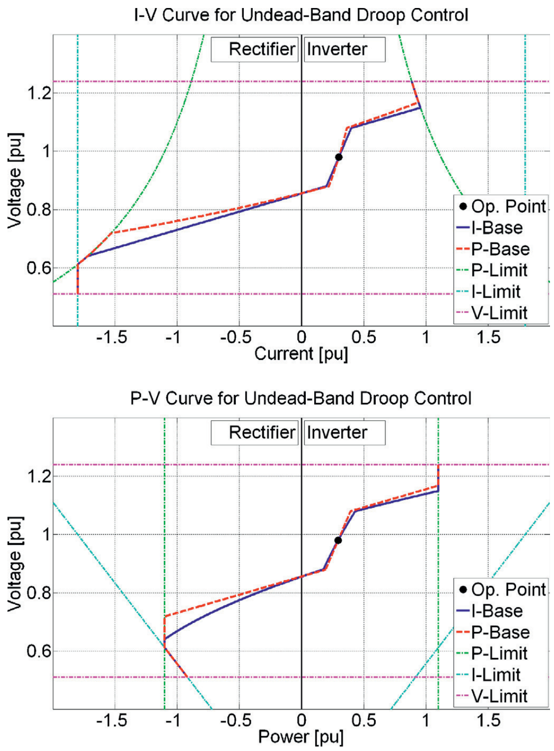

Fig. 7. *I–V* curve and *P–V* curve for undead-band droop control.

normal operating conditions. Since only one converter has to account for all disturbances within a grid, this method would only be applicable for relatively small fluctuations around the operation point in a larger system. With increasing network size, current/power fluctuations increase as well, thereby finally limiting the applicability of centralised voltage control. This type of operation would also have a significant influence on the AC system connected to that converter.

The most critical problem, however, is how to handle severe disturbances such as an imbalance, which exceeds the capabilities of the slack bus or the outage of the DC slack bus, for which no back-up control is provided.

6.2. Distributed voltage control

Distributed balancing control is applied to all large AC power systems and it is therefore a natural thought to consider this control method for DC power systems as well [29]. Distributed voltage control is implemented by applying droop control to all converters (Section 4.1).

It is not necessary that all converters take part in the control of the DC voltage. Droop controlled converters and current/power controlled converters can easily be integrated into the same DC grid. This is similar in AC grids, where some power stations take part in primary frequency control while others do not.

The integration of voltage controlled converters could cause problems: Similar to a frequency droop in AC systems, the power sharing amongst different droop controlled converters is determined by the relative droop values of the different converters. The smaller the droop value, the higher the share of a particular converter in the power sharing. A voltage controlling converter can be considered as the limiting case for the droop constant going to zero, thereby significantly reducing the power sharing of the other converters. In this way, adding a voltage controlling converter would partly undermine the distributed control principle of droop control. In this case only the changes in the voltage droops on the lines determine the changes in the operation points of the droop controlled converters, leading to small control contributions.

7. Advanced grid control strategies

The advanced grid control strategies are based on the advanced converter control strategies from Section 5. Compared to the basic strategies the main difference is the inclusion of back-up mechanisms to handle large disturbances. For distributed voltage control, this back-up is an improvement, while for centralised voltage control, it is a necessity as illustrated in Section 6.

7.1. Centralised voltage control with centralised back-up

The back-up system for the centralised control method can be implemented with the centralised approach as well. That means that a converter that normally controls current/power switches to voltage control to take over the task from the regular voltage controlling converter. The modification from centralised voltage control is to replace the converter controllers with constant current/power control with voltage margin control.

If the voltage deviates significantly (i.e. the voltage controlling converter fails to do his task), a converter with voltage margin control hits the limit of the voltage margin and turns into a new DC slack bus and starts to control the DC voltage at the limit of the voltage margin. In this way, the task of the slack can be passed back and forth between converters many times.

For smaller DC systems, this control can be a good choice, as long as the converter ratings and the system rating are in the same range. One slack bus converter can be selected, but for extraordinary conditions other converters help out. This is similar to the real implementation used in point-to-point connections.

For large DC systems this method might pose problems. With increasing system size, operation modus changes will appear more often. This creates highly nonlinear system behaviour, where local voltage measurements lose its information on the general system state. Furthermore, when more converters participate in the voltage margin control, the number of voltage steps increases, which might give rise to voltage deviations that are too large. These two factors make it complicated to oversee and therefore control the network.

7.2. Centralised voltage control with distributed back-up

A better way to provide a back-up mechanism for centralised voltage control for large DC grids is to use dead-band droop control instead of voltage margin control. If the voltage controlling converter fails, the voltage control task is not transferred to another converter (as with voltage margin control), but to all other converters with a distributed approach. At larger disturbances, the consequences are split among all converters leading to a new stable operating point.

Compared to voltage margin control, this method can provide an improvement when it comes to handling large disturbances. However, it still faces similar problems under normal operation for very large power systems, where the converter ratings are very small compared to the system rating. The regular power fluctuations increase with system size, eventually exceeding the capability of one single converter, and therefore operation outside the dead-band is likely to become more frequent.

7.3. Distributed voltage control with distributed back-up

Generally, the distributed voltage control can safely operate a DC grid without a back-up mechanism. But still, also with a distributed voltage control approach, it might be desirable make a distinction between normal and disturbed operation, e.g. stay close to the operation point under normal conditions, as discussed in [26], whilst having a back-up control with different settings. In this way, converters with droop control that contribute to voltage control can increase their contribution (lower droop value) in case of a severe disturbance. This can be implemented with undead-band droop control.

Similarly, current/power controlled converters that do not contribute to voltage control could in some cases be implemented as dead-band droop controlled converters, thereby also contributing to the voltage control back-up system.

8. Conclusion

The currents in and out or a DC grid can be balanced by controlling the node voltages within defined limits. The DC node voltage can be influenced by controlling the current/power of the HVDC converter at that node. To ensure secure operation of the DC grid, the control should be robust and reliable and to some degree distributed and autonomous. It should also be flexible and easily expandable.

In this paper three overall converter control strategies are systematically introduced: constant voltage control, constant power/current control and voltage droop control. It has been discussed to which extent these control strategies comply with or compromise the control requirements. It has been discussed that the constant current/power control and constant voltage control characteristics theoretically can be regarded as limiting cases of the droop control. The control concepts can be combined, leading to more advanced converter control strategies such as voltage margin control, dead-band droop control or undead-band droop control. These advanced converter control strategies distinguish between normal and disturbed operation.

Based on the introduced basic converter control strategies, two basic grid control strategies are introduced and classified: Centralised and distributed voltage control. The application of the advanced converter control strategies results in advanced grid control strategies, which have a back-up system to handle large disturbances.

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Active Power Control with Undead-Band Voltage & Frequency Droop for HVDC Converters in Large Meshed DC Grids

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Abstract:

A new control method for large meshed HVDC grids has been developed, which helps to keep the active power balance at the AC and the DC side. The method definition is kept wide, leaving the possibility for control parameter optimisation. Other known control methods can be seen as specific examples of the proposed method. It can serve as a framework for the control of large DC grids, defining a common standard for the control scheme, but still leaving a lot of freedom for individual adjustments.

The proposed method is based on a so called “undead”-band, meaning that control activity is reduced within the band, but not set to zero as with a regular dead-band. It operates with a minimum of required communication. New converters can be added to the system without changing the control of the other individual converters. It is well suited to achieve high reliability standards due to the distributed control approach.

Keywords:

HVDC, Power Converter, Control, Droop, Meshed DC Grids, Dead-Band

Active Power Control with Undead-Band Voltage & Frequency Droop
Applied to a Meshed DC Grid Test System

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Dynamic Active Power Control with Improved Undead-Band Droop for HVDC Grids

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