

Virtual Inertia Control for Frequency Stabilization in a Shipboard Microgrid

Implementing virtual synchronous generator
control for grid-connected converters

Master of Science Thesis

Maya Peeters



Virtual Inertia Control for Frequency Stabilization in a Shipboard Microgrid

Implementing virtual synchronous generator
control for grid-connected converters

by

Maya Peeters

to obtain the degree of Master of Science
at the Delft University of Technology
to be defended publicly on Wednesday July 1, 2026 at 10:00 AM.

Thesis committee:	Dr. J. Dong	TU Delft, supervisor
	Dr. F. A. Muñoz Muñoz	TU Delft
	P. Roodnat	ABB, company supervisor
External supervisor:	M. Zevenbergen	ABB, company supervisor
Project Duration:	November 11 2025 - June 23 2026	

Style:	When writing this thesis, Gemini pro was used for inspiration, and to improve the spelling, grammar and/or style of the text.
Cover image:	TU Delft Report Style, with modifications by Daan Zwaneveld
	ABB Cable Layer from Saltship

Acknowledgements

First of all I would like to thank my TU Delft supervisor Jianning Dong for his guidance and support throughout this master thesis. You were always open to answering any questions and helping me with the next steps of the project. I would like to thank my supervisors at ABB, Marcel Zevenbergen and Peter Roodnat. Thank you Marcel for getting me acquainted at ABB and for always having a solution or a good contact to solve the problem I was facing. Thank you Peter for your help during the implementing and testing phase, when I was stuck you were always open to help me and quick to pinpoint the problems with my test setup. Thank you to Martijn Aangeenbrug, Robin Huber and Ying Jin, for your feedback, support and encouragement. Also for getting me acquainted with the ABB drives.

Next I would like to thank Serge Blufpand for the many hours he put into helping me to ensure I can test my controller in the test setup. I would like to thank Ville Pirsto and Tuomas Pulli for always being reachable and quickly responding to my questions with regards to virtual drive and Crealizer. Thank you Ryan Koorts for sharing with me the software development kit, providing the training and always being open to help or provide support. I would like to thank the rest of my colleagues at ABB for making my time there pleasant and memorable.

Lastly I would like to thank my friends and family for supporting me through this time and listening to my endless rants on this topic. Especially my parents and Kore who had to sit through my ups and downs in this project and stood by my side even though I don't think they always fully understood what I was talking about.

*Maya Peeters
Delft, June 2026*

Abstract

Shipboard microgrids are inherently weak systems due to their limited inertia and high impedance, making them prone to voltage and frequency fluctuations during faults and load changes. These challenges are further intensified by highly dynamic load conditions and the ongoing hybridization of shipboard power systems, where conventional diesel generators, functioning as synchronous generators, are increasingly being replaced by renewable energy sources (RES) and energy storage systems (ESS). As a result, the overall rotational inertia of the system is reduced, degrading its frequency stability.

This thesis proposes a method to emulate inertia using an ESS by implementing a virtual synchronous generator (VSG) control scheme. The ESS, interfaced through a power converter connected to the microgrid, replicates the kinetic energy behavior of a synchronous generator, providing both frequency and voltage support. A detailed Simulink model of a shipboard microgrid was developed, including converters, loads, synchronous generators, and grid-connected and islanded configurations. The VSG control scheme was designed and tuned based on system parameters, and its performance was evaluated through simulations and experimental testing.

Results demonstrate that a VSG control scheme based on the swing equation successfully provides virtual inertia, improving frequency stability by improving the frequency nadir and reducing the rate of change of frequency (RoCoF) by 85%. In addition, the integration of integral Q–U droop control effectively regulates voltage, ensuring deviations remain within acceptable limits. The proposed control strategy is particularly beneficial for load variations exceeding 1 kVA/s and maintains stable operation even in islanded mode when synchronous generators are disconnected.

The study also identifies key design trade-offs, including the balance between frequency settling time and nadir, as well as between RoCoF reduction and power oscillations, which are influenced by the damping and inertia parameters. Similarly, voltage performance depends on the tuning of reactive power droop parameters, affecting both voltage deviation and dynamic response.

In conclusion, the use of VSG-based virtual inertia significantly enhances the stability of low-inertia shipboard microgrids, particularly in the context of increasing system hybridization. Future work should focus on optimal ESS selection, higher-level energy management strategies, and adaptive tuning of control parameters.

Contents

Preface	i
Summary	ii
Nomenclature	v
1 Introduction	1
1.1 Motivation	2
1.2 Research Objective	3
1.3 Structure of this thesis	3
2 Grid stability and grid-tied converter: Background knowledge	4
2.1 Grid stability	4
2.1.1 System requirements	5
2.2 The synchronous generator and its influence on frequency	6
2.3 Converter Control	8
2.3.1 Clarke and Park transform	10
2.3.2 Voltage and current control	11
2.3.3 Power and synchronization control	11
3 Grid-forming and Supporting Control Strategies	13
3.1 Grid-forming and Grid-following control	14
3.2 The difference between droop control and VSG control	14
3.3 VSG control schemes	15
3.3.1 Synchronverter	16
3.3.2 Ise's lab	17
3.3.3 VSYNC	17
3.3.4 Comparison	18
4 Description of the microgrid	19
4.1 Model of the microgrid	19
4.1.1 State-space representation	19
4.1.2 Transfer function	21
4.2 Response of the microgrid	21
5 Implementation and tuning of VSG	24
5.1 Voltage and current control	25
5.1.1 Tuning the PI controller	26
5.2 Active and Reactive power control	27
5.2.1 Modeling the power control loop	29
5.2.2 Setting the reference power	30
5.3 Discretizing the control	32
5.4 Final Design parameters	32
6 Simulation and control validation	34
6.1 Modeling the microgrid in Simulink	34
6.2 Modeling the synchronous generator	35
6.3 Simulation results	36
6.3.1 Initial model	36
6.3.2 Islanded mode	40
6.3.3 Connected to Synchronous generator	42

7	Deployment and field testing	45
7.1	Setup	45
7.1.1	Load profiles	45
7.2	Controller Adaptations	47
7.3	Testing results	48
7.3.1	Islanded mode	49
7.3.2	Grid-connected mode	52
7.3.3	Tuning the droop constants	55
7.3.4	Tuning the inertia coefficient and damping constant	56
7.4	Comparing simulation and testing	58
8	Discussion	61
8.1	Effectiveness of VSG control	61
8.2	Islanded vs grid-connected mode	61
8.3	Limitations	62
8.4	Model assumptions and simplifications	62
9	Conclusion and future work	63
9.1	Future Work	64
	References	65
A	Mathematical derivation of the dq-reference frame coupling	68
B	Cross-coupling	69
C	Simulink Models	70
D	Discretization of the simple RL circuit	72
E	Results of tuning the inertia and damping parameters	73
F	Simulation Results	74
F.1	Islanded mode	74
F.2	Grid-connected	75
F.2.1	Tuning Reactive Power Control Loop	78
G	Test results	79

Nomenclature

Abbreviations

Abbreviation	Definition
AVR	Active Voltage Regulation
ESS	Energy Storage System
GFL	Grid-following
GFM	Grid-forming
PCC	Point of Common Coupling
PLL	Phase Locked Loop
PSC	Power Synchronisation Control
RES	Renewable Energy Sources
RoCoF	Rate of Change of Frequency
SG	Synchronous Generator
SVPWM	Space Vector Pulse Width Modulation
VSC	Voltage Source Converter
VSG	Virtual Synchronous Generator

Symbols

Symbol	Definition	Unit
V_d	d-axis voltage	[V]
V_q	q-axis voltage	[V]
$V, V $	Voltage magnitude	[V]
V_{dc}	DC voltage	[V]
i_d	d-axis current	[A]
i_q	q-axis current	[A]
P_{SG}	Mechanical input power	[W]
P_e	Electrical output power	[W]
Q	Reactive power	[VAr]
t	Time	[s]
L	Inductance	[H]
C	Capacitance	[F]
R	Resistance	[Ω]
J	(Virtual) inertia coefficient	[kg · m ²]
D	Damping constant	[N · m · s/rad]
k_u	Voltage droop coefficient	[VAr/V]
k_q	Reactive power droop coefficient	[V/(VAr · s)]
k_p	Proportional gain PI controller	-
k_i	Integral gain PI controller	-
ω	Angular frequency	[rad/s]
ω_g	Grid frequency	[rad/s]
ω_c	Cut-off frequency	[rad/s]
f	Electrical frequency	[Hz]
θ	Phase angle	[rad]
δ	Load angle (rotor angle)	[rad]

1

Introduction

The shipping industry is experiencing sustained growth. This expansion is driven by traditional global trade, which accounts for 80% of global commerce volume, as well as the increasing demand for specialized logistics supporting offshore wind energy infrastructure. However, this growth relies heavily on diesel generators as the primary power source for shipboard microgrids. The resulting combustion of fossil fuels accounts for roughly 2.5% of global greenhouse gas emissions, a figure that is projected to increase [18]. In response to this trend the International Maritime Organization (IMO) has published emission reduction policies which state that greenhouse gases must be reduced by 20% by 2030. Among other solutions, to achieve these goals, diesel generators are replaced by renewable energy sources (RES) in combination with energy storage systems (ESS) [17]. Currently studied RES include solar panels, small wind turbines and wave energy conversion systems [5]. Utilizing alternative power sources and a hybrid system reduces the environmental impact, while maintaining the capacity necessary to meet fluctuating loads. However, this integration leads to operational challenges, regarding both system stability and power management.

The microgrid on a marine vessel is already considered a weak grid. Firstly, a microgrid has a high impedance with respect to its generation capacity, due to the overall smaller size of the system. High impedance levels lead to limited short-circuit capacity [1]. Secondly, compared to a standard grid, a microgrid operates with limited inertia. Defined as the kinetic energy stored in a synchronous generator's rotating mass, inertia allows the machine to respond to power imbalances by resisting its change in speed [1]. The inertia of a synchronous generator (SG) is dependent on the mass of its rotor. Shipboard diesel generators possess inherently less inertia because they are significantly smaller than the generators connected to the main grid. Limited inertia leads to restricted capacity to manage power fluctuation, making the microgrid more susceptible to frequency instability, especially during load changes. This vulnerability is critical on ships as the shipboard's microgrid is exposed to abrupt load changes due to external disturbances. Take for example changes in propulsion requirements due to the influence of waves and wind on the ship. Thus, the fluctuating power demand and limited inertia causes frequency fluctuations in the system that are difficult to stabilize.

Replacing the diesel generator with inverter-based RES further reduces system inertia, as power electronics lack the inherent inertial response of a SG. However, inertia can still be implemented via the ESS used in hybrid architectures. By integrating the mathematical equations that define the behavior of an SG in the converter control loop, the ESS can be commanded to release or absorb power, thereby emulating the kinetic energy stored in the rotating mass of the SG. Consequently, the grid converter mimics the behavior of the SG [1]. Thus, the proposed solution is to implement a controller for a grid-converter connecting the ESS to a shipboard microgrid such that the ESS can provide the required inertial response for frequency stabilization.

To illustrate the integration of the proposed solution, the hybrid architecture of a shipboard microgrid is shown in Figure 1.1. The diesel generators (G) supply power to the system and are connected to a common bus, which forms the main distribution node of the shipboard microgrid. Various loads

are connected to the bus, including propulsion systems, pumps and compressors, heating, ventilation and air conditioning (HVAC) systems, control and communication equipment, and hotel loads. The propulsion system is driven by a motor (M) connected to the grid via a drive, while other loads are connected through a transformer and represented as L_1 and L_2 [8]. The proposed ESS-based solution is connected at the Point of Common Coupling (PCC). Through a grid-connected converter and its associated controller, the ESS provides a virtual inertia response based on measured system parameters. The red connections indicate the measurements and control signals required for the implementation of this solution. The virtual inertia control strategies found in literature are applied based on this micro-grid architecture. The controller should therefore be tuned based on the grid characteristics and the behavior should complement the operation of the diesel generators.

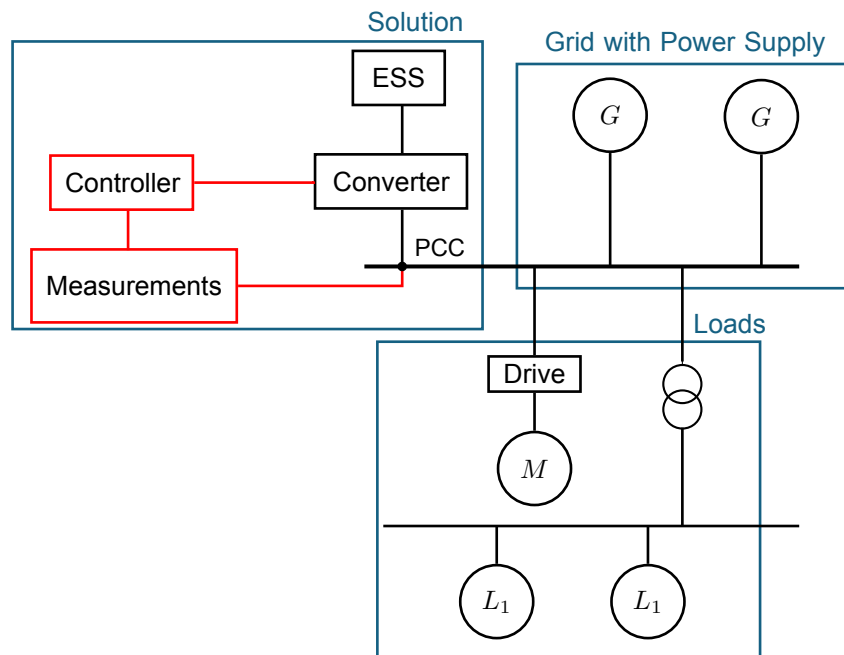


Figure 1.1: Shipboard grid architecture with proposed solution [8]

1.1. Motivation

The weak and unstable nature of a microgrid, due to its large impedance and limited inertia, imposes challenges in stabilizing the grid. Especially on a ship where large loads abruptly change in demand, generators must react quickly to compensate for a mismatch in power, causing voltage and frequency fluctuations. A common approach to mitigating these fluctuations is by providing extra inertia through over designing and maintaining a spinning reserve. These methods however, are costly, and require a lot of space and weight [8]. Therefore, applying the additional inertia virtually through an ESS can be beneficial. Especially with the current research in the hybridization on shipboard microgrids, where the integration of RES in combination with an ESS is becoming a preferred solution [12]. Furthermore, the fast response of these storage systems is ideal for quickly compensating power mismatches during load changes, thereby enhancing grid stability. To ensure a quick response the converter connecting the ESS to the grid must be controlled properly. It cannot rely on communication protocols between SGs, loads and the converter, as this would cause delays slowing down the response. Therefore, the controller should ideally rely on measurements from the system such as frequency or power deviations. This is achieved by mimicking the physical inertial response of an SG. By doing so the converter is controlled to quickly respond to load changes and cooperate with the rest of the grid without any initial communication.

1.2. Research Objective

The objective of this thesis is to implement virtual inertia control using an ESS based DC supply in combination with a grid converter to aid frequency recovery after load changes on a ship's microgrid. The controller that controls the grid converter is programmed using ABB's Crealizer™ controller software. Implementing inertia virtually will not only improve frequency stability, but also facilitate the integration of RES by overcoming the barriers associated with low-inertia grids. The goal of my thesis can be summarized in the following research question.

What is the value of implementing inertia virtually to the stability of a ships microgrid?

To help answering the main research question the following five sub-questions are derived.

- How is frequency stability defined?
- Why are grid-forming converters instead of grid-following converters becoming more important for microgrids?
- How does VSG control help stabilize frequency?
- What are the advantages and disadvantages of implementing inertia virtually?
- How is virtual inertia based on an ESS implemented in a grid-tied converter?

1.3. Structure of this thesis

This thesis is structured as follows. Chapter 2 provides background information on grid stability, the SG and the fundamentals of converter control. Chapter 3 presents a rigorous analysis of the prominent inertia control strategies. Chapter 4 describes and analyzes the shipboard microgrid in which frequency stabilization is implemented. This is followed by Chapter 5 which outlines the controller structure used to achieve this objective. Furthermore, Chapter 6 details the MATLAB Simulink model of the system and presents the corresponding simulation results. Chapter 7 describes the test setup and reports the test results. The findings are subsequently discussed and summarized in Chapter 8, while Chapter 9 provides the main conclusions of this thesis.

2

Grid stability and grid-tied converter: Background knowledge

In this chapter, grid stability is first defined, followed by an outline of the associated requirements. Subsequently, the fundamental concepts of the SG and grid-tied converters are presented.

2.1. Grid stability

To determine whether the virtual inertia implementation has established grid stabilization, grid stability must first be defined. Grid stability is defined within three main categories: rotor angle stability, frequency stability and voltage stability.

Rotor angle stability refers to the ability of the generator to remain in synchronism. The rotor angle is the difference between the phase angle of the SGs field voltage (across the rotor windings) and terminal voltage (across the stator windings). When a load is connected, the field voltage leads the terminal voltage and the load angle is positive. The size of the load angle depends on the size of the load connected. Thus, a higher load means a larger load angle. If the load increases past a certain threshold at which the load angle deviates past 90 degrees, the field voltage falls out of synchronism from the terminal voltage and the SG is disconnected from the system, hence losing system stability. Besides the rotor angle displacement, an acceleration of the rotor angle can also lead to instability. According to the swing equation, the rotor angle is said to be stable if it does not accelerate, thus when the net power is zero. The swing equation, presented in Equation 2.1, is the fundamental relation governing the dynamic behavior of the synchronous generator (SG). In this equation, P_{SG} and P_e represent the mechanical power supplied by the SG and the electrical power demanded by the load, respectively, in Watts (W). The term ω_s denotes the synchronous speed (rad/s), which corresponds to the grid frequency under steady-state conditions. The variable δ represents the rotor angle (rad), and J is the moment of inertia of the rotor ($\text{kg}\cdot\text{m}^2$), also referred to as inertia coefficient. If there is an unbalance between demand and supply the rotor angle will accelerate or decelerate [28]. The power supplied by the generator must therefore change to match the demanded power by the load to ensure a steady state condition where the acceleration is brought to zero. Lastly, according to [9] the system is said to be stable if the rotor angular differences from all SGs connected to the system decrease after a load switch.

$$P_{SG} - P_e = J\omega_s \frac{d\delta}{dt} \quad (2.1)$$

Furthermore, frequency stability is a key factor in power system stability. It reflects the system's ability to restore a balance between generated power and load power with minimum loss of load. The initial frequency response following a disturbance is determined by the systems inertia, which influences the Rate of Change of Frequency (RoCoF) as defined in Figure 2.1. A high RoCoF can trip protection

relays, disconnecting the generator from the system. Another critical parameter is the frequency nadir, defined as the lowest frequency reached following a disturbance. System inertia indirectly affects nadir as well, since higher RoCoF leads to a deeper frequency dip. If the frequency nadir of the system falls below acceptable limits, it may activate low-frequency load shedding mechanisms [26].

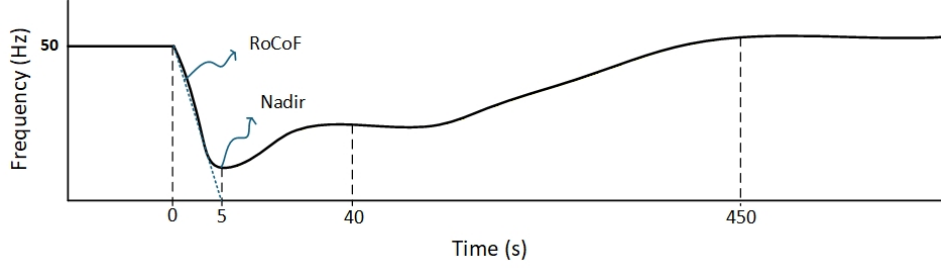


Figure 2.1: The effect of a load change on system frequency

Lastly, voltage stability should also be taken into consideration. This is the ability of the system to maintain the same voltage levels after a disturbance [28]. The main factor causing instability in voltage levels is the inability of the system to meet the reactive power demand [21]. In an SG the voltage is controlled using the active voltage regulation (AVR). The AVR sets the voltage across the field windings based on droop control. Equation 2.2 presents a basic form of droop control. Fundamentally, droop control determines the voltage across the field windings V (V) based on a voltage setpoint V_{set} (V) and the error between the measured reactive power Q (var) and the reactive power setpoint Q_{set} (var). The extent to which the voltage deviates from its setpoint in response to the reactive power error is determined by the droop constant k_q (V/VAr). In principle the droop constant determines the weight of the reactive power error. Droop control is implemented, because it ensures all SGs connected to the network deliver the required reactive power to achieve the same field voltage.

$$V = V_{set} - k_q(Q - Q_{set}) \quad (2.2)$$

2.1.1. System requirements

Now that power system stability is defined, the requirements of the proposed solution can be derived. The system and its proposed solution are shown in Figure 1.1. The grid line-to-neutral rms voltage is 230 V and the power capacity of the system is 85 kVA. The proposed solution is shown where the red components represent the externally connected components to the system. This indicates where the voltage and current are measured and sent to the controller. A more in-depth analysis of the system is presented in Chapter 4. The requirements are in terms of voltage and frequency stability and are defined in Table 2.1. These requirements are set based on the grid compliance code [16] and the IEEE guide [6].

Parameter	Requirement
Power step (ΔP)	20 kVA
Maximum RoCoF	0.5 Hz/s
Maximum Nadir	2 %
Maximum Frequency peak	2 %
Maximum frequency settling time	30 seconds
Maximum voltage deviation	1 %
Maximum voltage recovery time	10 seconds

Table 2.1: The system requirements of the proposed solution

The frequency settling time is defined from the moment the frequency changes (so at the point of the disturbance) until the frequency is back within 0.1% of its original value. For a frequency of 50 Hz this

would mean 49.95 Hz in case of an increase in load and 50.05 Hz in case of a decrease in load. The same definition holds for the voltage recovery time. The requirements are set for a power step of 20 kVA. In addition to these requirements the converter must operate in two scenarios defined below.

Scenario one (Islanded mode): Following grid initialization, the synchronous generator (SG) disconnects, forcing the converter to switch to islanded mode. During this isolation period, which is mostly brief, the converter must autonomously regulate its own voltage and frequency while dynamically managing load changes until the generators reconnect.

- Converter is connected to the microgrid.
- No SG is connected.
- A changing load is connected to the microgrid.
- The power demanded by the load changes after system is stabilized.
- Converter must set own frequency and voltage once SG is disconnected.
- Converter must reach a steady state frequency of 50Hz after load change.

Scenario two (Grid-Connected Mode): The converter operates in parallel with an SG to support a common load. In this configuration, the converter is responsible for accurately sharing the load demand with the SG.

- The grid is established by the SG.
- Converter is also connected to the same grid.
- The power demanded by the load changes after connection of converter is stabilized.
- Converter only supplies or absorbs load power during transient.

2.2. The synchronous generator and its influence on frequency

Mechanical power is converted to electrical power through the magnetic field of an SG. The power conversion system from mechanical to electrical power using an SG can be split up into 5 main components. The generator itself, its windings (field winding, armature winding and damper winding), the AVR and the prime mover and its governor. An overview of these components can be seen in Figure 2.2a. How the SG is connected to the rest of the microgrid can be seen in Figure 1.1.

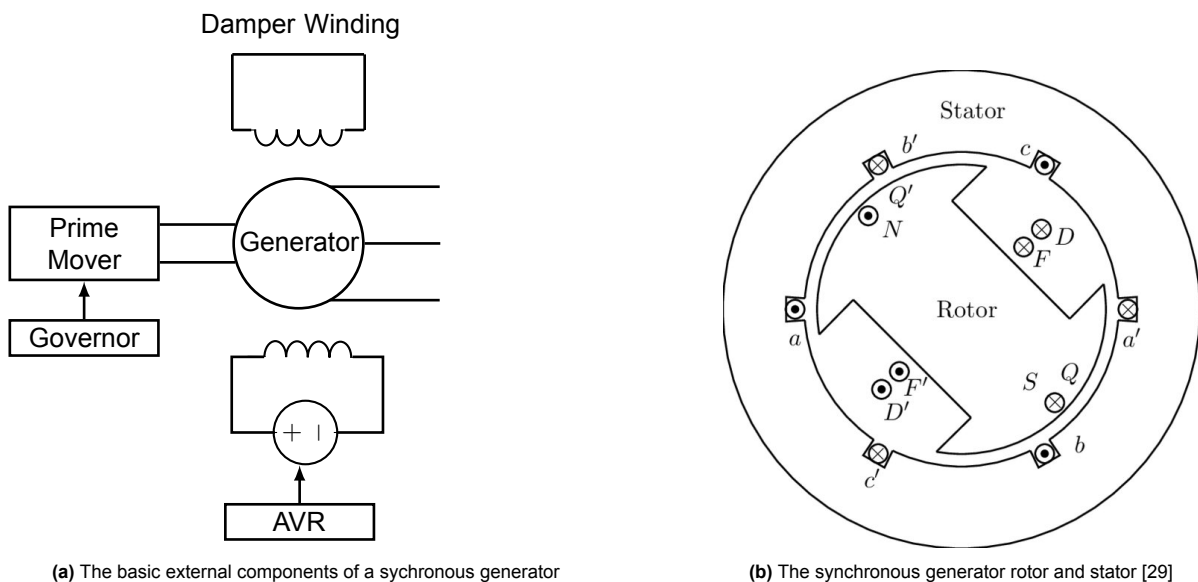


Figure 2.2: The synchronous generator

The generator itself comprises a shaft, rotated by a prime mover, such as a steam turbine or diesel engine, which is mechanically coupled to the rotor. The rotor is equipped with a field winding, denoted by F and F' in Figure 2.2b, which is energized by a DC voltage, setting a constant magnetic flux. The DC voltage is regulated by the AVR. By setting the field winding voltage, hence influencing the excitation current, the AVR can govern the terminal voltage of the generator. Rotating the shaft, thus subsequently the rotor, generates a rotating magnetic field which induces an AC voltage in the armature windings. The armature windings, also referred to as stator windings, are coils wound around the stator of the SG. These are denoted with aa' , bb' and cc' in Figure 2.2b, each representing one of the three grid phases. Once the generator is synchronized and connected to the grid, the induced voltage in the stator windings causes an AC current to flow, thereby delivering electrical power to the system. The frequency of the grid is determined by the rotational speed of the rotor inside the generator. The relationship between the rotational speed of the generator and the frequency is given by Equation 2.3, where, n_s is the synchronous rotational speed of the generator (rpm), f is the electrical frequency (Hz) and P is the number of pole pairs.

$$n_s = \frac{60f}{P} \quad (2.3)$$

The SG can also include an extra winding around the rotor, namely the damper windings, denoted by DD , and QQ' in Figure 2.2b. These windings are used to dampen the frequency oscillations. When the generator runs at synchronous speed, no current is induced in this winding. An increase in load will cause a resultant magnetic flux inducing current in the damper windings. This current produces a restorative torque to counteract the pulsating torque, restoring the synchronous speed, hence the frequency of the system [20].

The dynamic behavior of the SG is governed by the electromagnetic interactions between its stator and rotor windings illustrated in Figure 2.2b. The mathematical relationships are illustrated in Equations 2.4–2.9. The subscript abc denotes the three-phase stator windings, f represents the field winding, and D and Q denote the damper windings. U is the voltage (V) across the winding and i (A) the current through the winding. Furthermore, M represents the mutual inductance (H), L the self-inductance (H), λ the magnetic flux linkage (Wb), and R the winding resistance (Ω). There is no mutual inductance between the D and Q damper windings as they are perpendicular to each other. Additionally, because these damper windings are physically short-circuited, they exhibit zero terminal voltage and experience no induced electromotive force (EMF) during steady-state operation [15].

$$U_{abc} = R_{abc}i_{abc} + \frac{d\lambda_{abc}}{dt} \quad (2.4)$$

$$U_f = R_f i_f + \frac{d\lambda_f}{dt} \quad (2.5)$$

$$0 = R_D i_D + \frac{d\lambda_D}{dt} \quad (2.6)$$

$$0 = R_Q i_Q + \frac{d\lambda_Q}{dt} \quad (2.7)$$

$$\begin{bmatrix} \lambda_{abc} \\ \lambda_f \\ \lambda_D \\ \lambda_Q \end{bmatrix} = \begin{bmatrix} L_{abc} & M_{abc,f} & M_{abc,D} & M_{abc,Q} \\ M_{abc,f}^T & L_f & M_{fD} & 0 \\ M_{abc,D}^T & M_{fD} & L_D & 0 \\ M_{abc,Q}^T & 0 & 0 & L_Q \end{bmatrix} \begin{bmatrix} i_{abc} \\ i_f \\ i_D \\ i_Q \end{bmatrix} \quad (2.8)$$

$$\begin{aligned}
U_{abc} &= \begin{bmatrix} U_a \\ U_b \\ U_c \end{bmatrix}, \quad i_{abc} = \begin{bmatrix} i_a \\ i_b \\ i_c \end{bmatrix}, \quad \lambda_{abc} = \begin{bmatrix} \lambda_a \\ \lambda_b \\ \lambda_c \end{bmatrix} \\
R_{abc} &= \begin{bmatrix} R_a & 0 & 0 \\ 0 & R_b & 0 \\ 0 & 0 & R_c \end{bmatrix}, \quad L_{abc} = \begin{bmatrix} L_{aa} & L_{ab} & L_{ac} \\ L_{ba} & L_{bb} & L_{bc} \\ L_{ca} & L_{cb} & L_{cc} \end{bmatrix} \\
M_{abc,f} &= \begin{bmatrix} M_{af} \\ M_{bf} \\ M_{cf} \end{bmatrix}, \quad M_{abc,D} = \begin{bmatrix} M_{aD} \\ M_{bD} \\ M_{cD} \end{bmatrix}, \quad M_{abc,Q} = \begin{bmatrix} M_{aQ} \\ M_{bQ} \\ M_{cQ} \end{bmatrix}
\end{aligned} \tag{2.9}$$

In steady state conditions, the power supplied by the SG is equal to the power demanded by the load. The rotor of the SG thus rotates at the synchronous speed and the net frequency is at nominal frequency. This can be seen up until $t=0$ seconds in Figure 2.1. At $t=0$ seconds a sudden change in load occurs, hence a change in power demanded by the system. However, the power supplied by the SG cannot instantly respond, so there is a mismatch between power demanded and supplied. This causes the rotational speed of the rotor to increase, in the case of a positive net power imbalance, or decrease in case of a negative power imbalance and as shown between $t=0$ seconds and $t=5$ seconds in Figure 2.1. The inertia, so the amount of kinetic energy stored in the mass of the rotor, determines the rate at which the rotor speed increases or decreases therefore determining the initial response of the system. This therefore has a direct influence on the RoCoF of the system and frequency nadir. After the change in frequency is detected, the governor, using droop control, determines a new power setpoint for the prime mover. The prime mover then produces this additional power, causing the rotor to accelerate until a new stable frequency setpoint is established, as can be seen between $t=10$ seconds and $t=40$ seconds in Figure 2.1. After the steady state is reached, secondary frequency control ensures the frequency is brought back to its grid value [26]. The frequency is initially brought back to a lower value due to the droop control in the governor. The droop control is required such that the load can be shared among multiple generators. This is further explained in Chapter 3.2.

2.3. Converter Control

Before introducing the prevailing converter control schemes, it is important to understand the communication between the controller and the system. This is summarized in Figure 2.3. The architecture of a hybrid shipboard microgrid consists of a diesel generator acting as the primary power source, modeled as an ideal voltage source V (V) connected to the grid through a grid impedance Z_g (Ω). The converter comprises an IGBT bridge and an LCL filter, which is used to attenuate voltage and current ripple. The voltage V_{PCC} (V) and current I_{PCC} (A) used for control are measured at the PCC, where the converter is connected to the rest of the grid. Based on these measurements, the controller determines the required output voltage magnitude $|V|$ (V) and phase angle θ_V (rad) at the converter output. These reference signals are then supplied to a pulse generator, which generates the appropriate switching signals for the IGBTs.

The control architecture of the prevailing control schemes used for grid converters can be seen in Figure 2.4. In essence, the voltage and current of the grid are measured and transformed to a dq-reference frame using the Park transform. The dq values are then, depending on the type of control, compared to voltage and current references which are derived from a power control loop. From this, a setpoint voltage is determined. This value is sent to the pulse generator which then generates the pulses for the IGBTs to ensure the correct converter output voltage.

The voltage, current, power and synchronization control loops differ for grid forming (GFM) and grid following control (GFL). A rigorous comparison between the two control strategies is made in Chapter 3.1. However, some simple differences between the two, with regard to their control architecture, will be touched upon in this chapter.

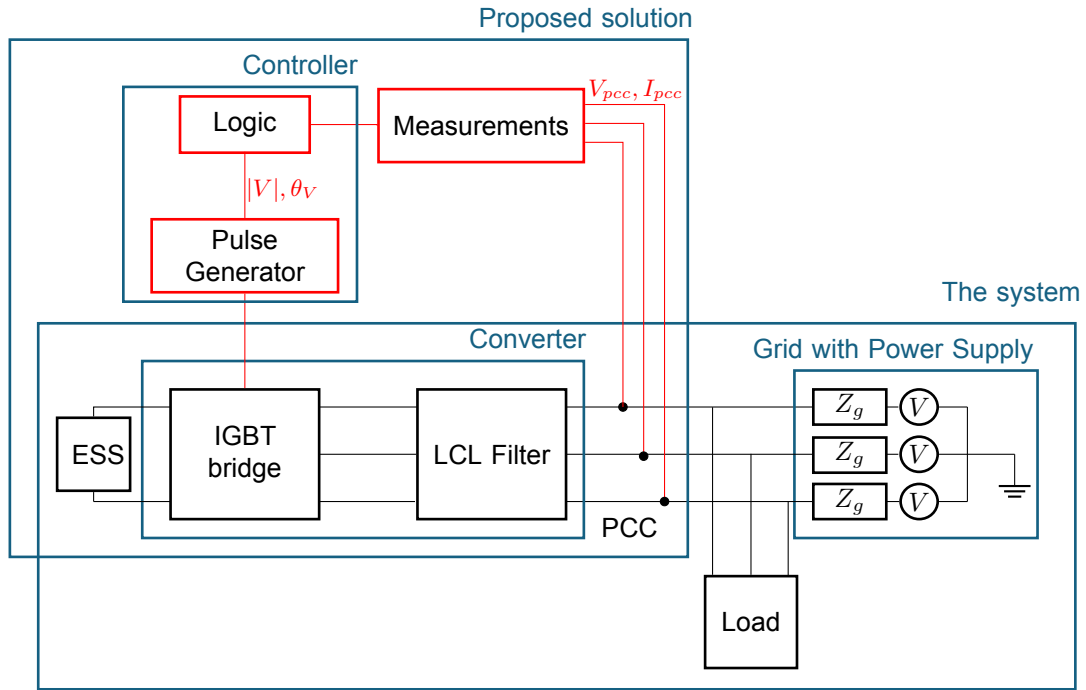


Figure 2.3: The architecture of a hybrid ship microgrid

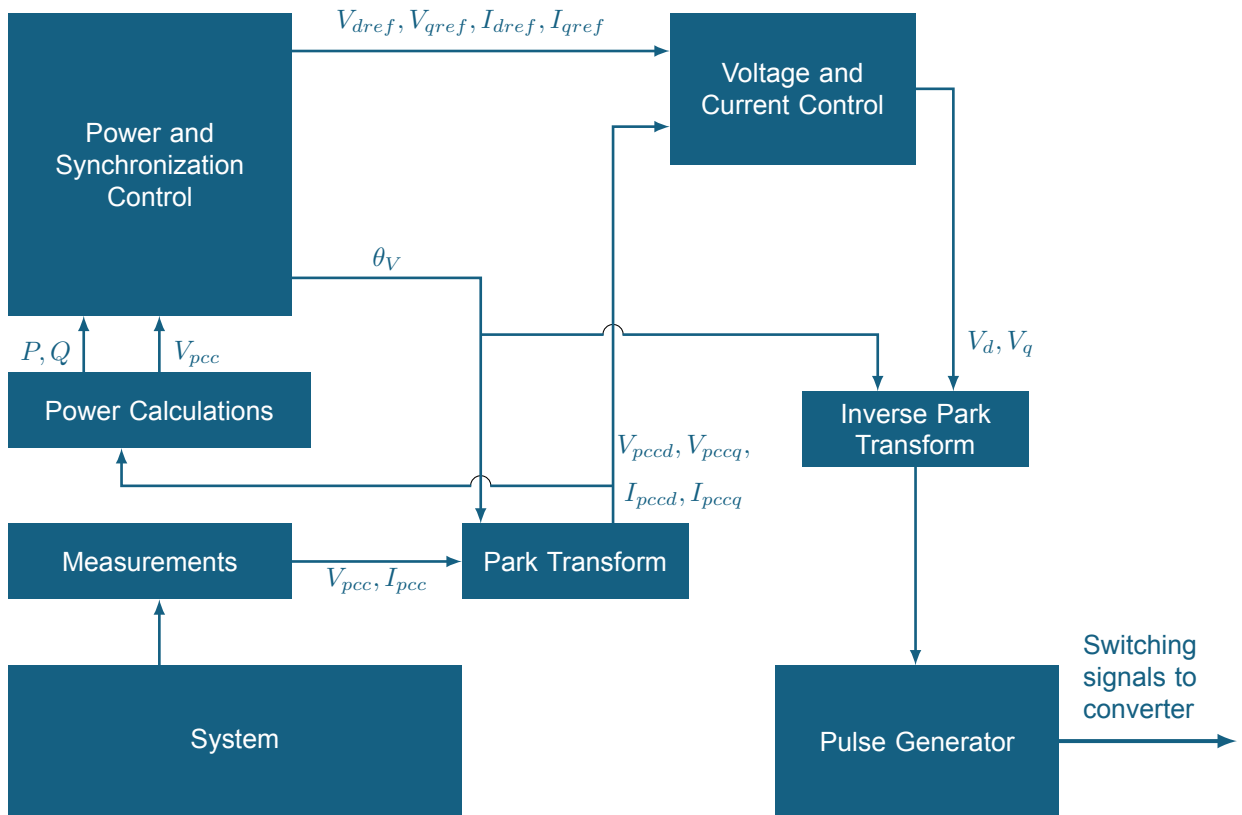


Figure 2.4: The structure of a converter control scheme

2.3.1. Clarke and Park transform

A controller determines the state of an electric system by measuring the currents and voltages. To simplify the dynamics of the controller it is beneficial to transform the three phase sinusoidal measurements to steady state values. This is achieved by transforming the values from the abc reference frame to a dq reference frame. First, by applying the Clarke transform, the system is transformed from a three variable to a two variable system, from the abc reference frame to the $\alpha\beta$ reference frame. Then the Park transform is applied to transform the system from a sinusoidal reference to two steady state values in the dq reference frame. In Figure 2.5 the transformations are shown. The Clarke transform converts a three-phase sinusoidal input to a two phase sinusoidal input by projecting each phase vector onto the $\alpha\beta$ reference frame. This can be seen in Figure 2.5b. Assuming the system is balanced, the $\alpha\beta$ components are 90 degrees shifted instead of 120 degrees. If the system is not balanced, there is also a zero component present. For the rest of this thesis the system is considered to be balanced, hence the measured signal is transformed from three to two parameters. The Park transform considers a rotating dq-reference frame, as seen in Figure 2.5c. This ensures the reference value is constant as the reference frame rotates with grid frequency such that the reference value relative to the frame remains constant. By transforming the three-phase measured voltages and currents to two steady state values the controller is simplified and can control the system more accurately [15].

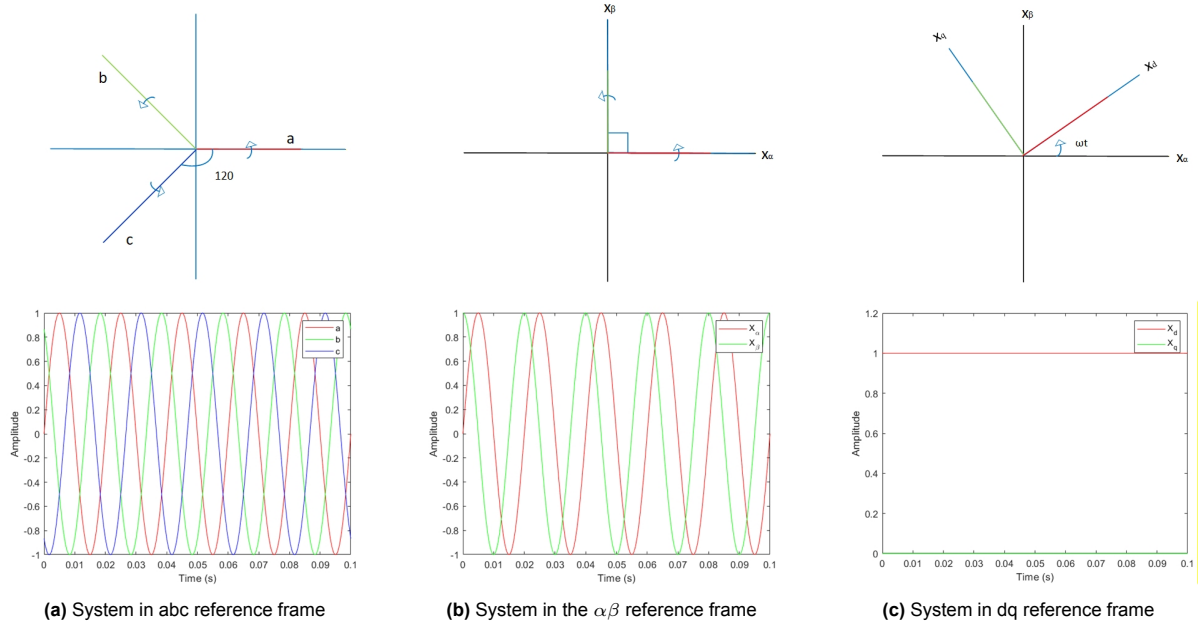


Figure 2.5: A three phase system represented as vectors and over time in different reference frames

The transformation matrices for the combined Clarke and Park transformation, which converts variables from the abc reference frame to the dq reference frame are shown in Equation 2.10. In this transformation θ is the phase angle of the output voltage phasor of the converter.

$$\begin{bmatrix} d \\ q \\ 0 \end{bmatrix} = \frac{2}{3} \begin{bmatrix} \cos(\theta) & \cos(\theta - \frac{2\pi}{3}) & \cos(\theta + \frac{2\pi}{3}) \\ -\sin(\theta) & -\sin(\theta - \frac{2\pi}{3}) & -\sin(\theta + \frac{2\pi}{3}) \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{2} \end{bmatrix} \begin{bmatrix} a \\ b \\ c \end{bmatrix} \quad (2.10)$$

The voltage and current phasors in terms of d- and q-axis components are represented in Equations 2.11 and 2.12 respectively. The power calculation from these d- and q-axis components is shown in Equations 2.13 and 2.14. The factor $\frac{3}{2}$ is present in the power calculation, because the amplitude invariant Park transform is used [32]. Furthermore, the calculated power signal is passed through a low-pass filter to eliminate noise on the voltage and current measurements.

$$V(t) = \frac{1}{\sqrt{2}}(v_d(t) + jv_q(t)) \quad (2.11)$$

$$I(t) = \frac{1}{\sqrt{2}}(i_d(t) + ji_q(t)) \quad (2.12)$$

$$P(t) = 3 \cdot \text{Re}\{V(t)I^*(t)\} = \frac{3}{2}(v_d(t)i_d(t) + v_q(t)i_q(t)) \quad (2.13)$$

$$Q(t) = 3 \cdot \text{Im}\{V(t)I^*(t)\} = \frac{3}{2}(v_q(t)i_d(t) - v_d(t)i_q(t)) \quad (2.14)$$

2.3.2. Voltage and current control

The most inner control loops are the voltage and current control loops. These determine the setpoint voltage at the output of the converter. A GFL converter only uses current control. The simplified control algorithm is shown in Figure 2.6a. It is evident that the current error is derived by comparing the measured current I_{measured} to a current reference I_{ref} derived from the power control loop. A PI controller then determines the voltage V required to set the current error to zero. This voltage setpoint is sent to the pulse generator.

In a GFM converter, represented in Figure 2.6b, the measured voltage V_{measured} is compared to a reference voltage V_{ref} derived from the power control loop. A PI controller then determines the required current to set the voltage error to zero. This current reference I^* is then compared to the measured current I_{measured} and again using a PI controller, a voltage setpoint, V , by which the current error is brought to zero, is derived. A simple PI controller will provide error-free operation, because the parameters are controlled in the dq reference frame [30]. In both controllers the acquired voltage setpoint, V , is transformed to the $\alpha\beta$ stationary reference frame and sent to the pulse generator. The pulse generator uses Space Vector Pulse Width Modulation (SVPWM) to generate the gate signals for the IGBTs such that the desired output voltage is achieved.

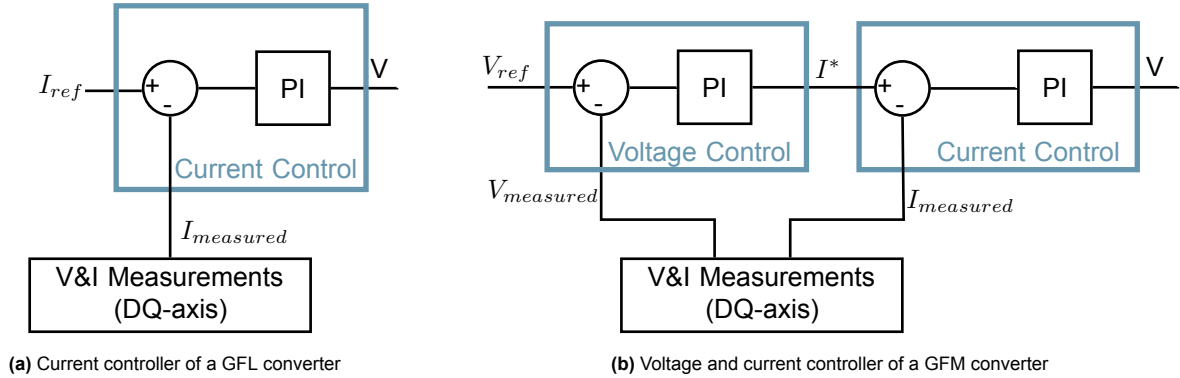


Figure 2.6: The simplified voltage and current control schemes for a GFL and GFM converter

2.3.3. Power and synchronization control

The power and synchronization control loop is where GFM and GFL converters differ the most. Namely, in GFL control the power control loop sets the reference current. While in GFM control the power control loops sets the reference voltage amplitude and phase angle.

In GFL control the active power control loop sets the d-axis current reference, and the reactive power control loop sets the q-axis current reference. This is done again using a PI controller and shown in Figure 2.7. The synchronization to the grid is established using a phase locked loop (PLL). A PLL estimates the grid frequency and corresponding voltage phase angle based on the measured system voltage. The phase angle in turn is used to synchronize the reference frame of the Park transform to the grid. The most common method of determining the system frequency is using a synchronous reference frame-PLL (SRF-PLL). This method is shown in Figure 2.8. The voltage at PCC is measured and converted to the dq reference frame using the Park transform and predicted phase angle. The Park transform outputs the d-and q-axis voltages. If the phase angle derived by the PLL is correct the q-axis voltage V_q should equal zero. If this is not the case there is a deviation in the voltage phase angle. The

PI controller than filters the signal and determines the change in frequency to set the phase angle error to zero. This frequency deviation is then added to the reference grid frequency and later integrated to determine the new voltage phase angle θ_V [25].

In GFM control the voltage reference is set by the reactive power control loop, while the voltage phase angle is set by the active power control. There are different control schemes to determine the voltage phase angle from an active power measurement and a voltage reference from a reactive power measurement. These are discussed more in detail in the next chapter. The eventual power and synchronization control used by the GFM developed in this thesis is explained in Chapter 5.2.

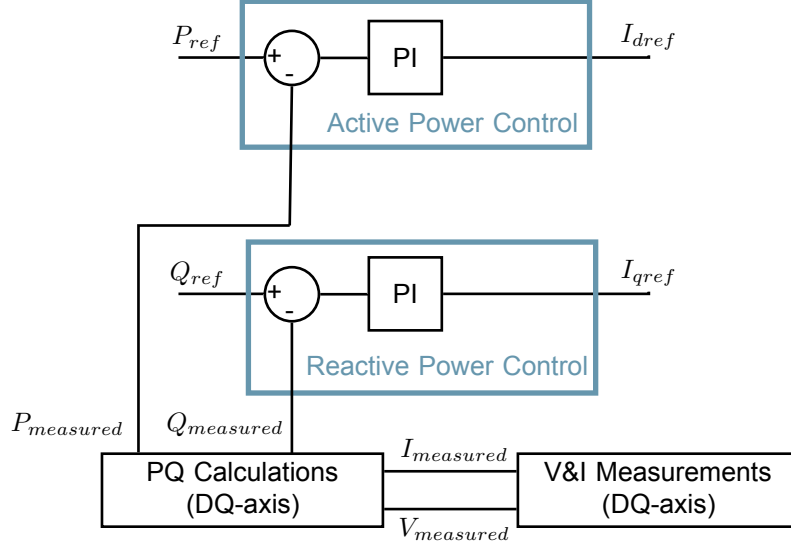


Figure 2.7: The power control loop of a GFL converter

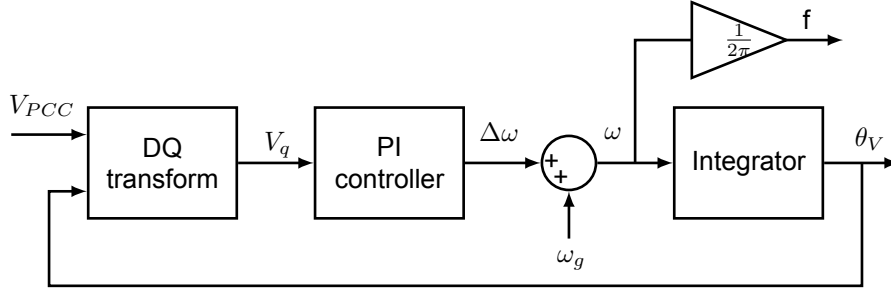


Figure 2.8: Structure of the PLL

3

Grid-forming and Supporting Control Strategies

Traditional control strategies for voltage source converters (VSCs) lack inertia and grid forming ability. These capabilities have become essential with the increase of converter dominated microgrids. That is why, over the past decades, researchers have proposed new grid forming and supporting control strategies which do have these necessary characteristics [14]. A overview of the key strategies is presented in Figure 3.1 and will be discussed in this chapter.

First, the differences between grid-forming and grid-following control strategies will be discussed. Additionally, the differences between droop and VSG control will be explained. Finally, a comparison on the three main VSG control strategies, the synchronverter, Ise Lab's and VSYNC, will be realized.

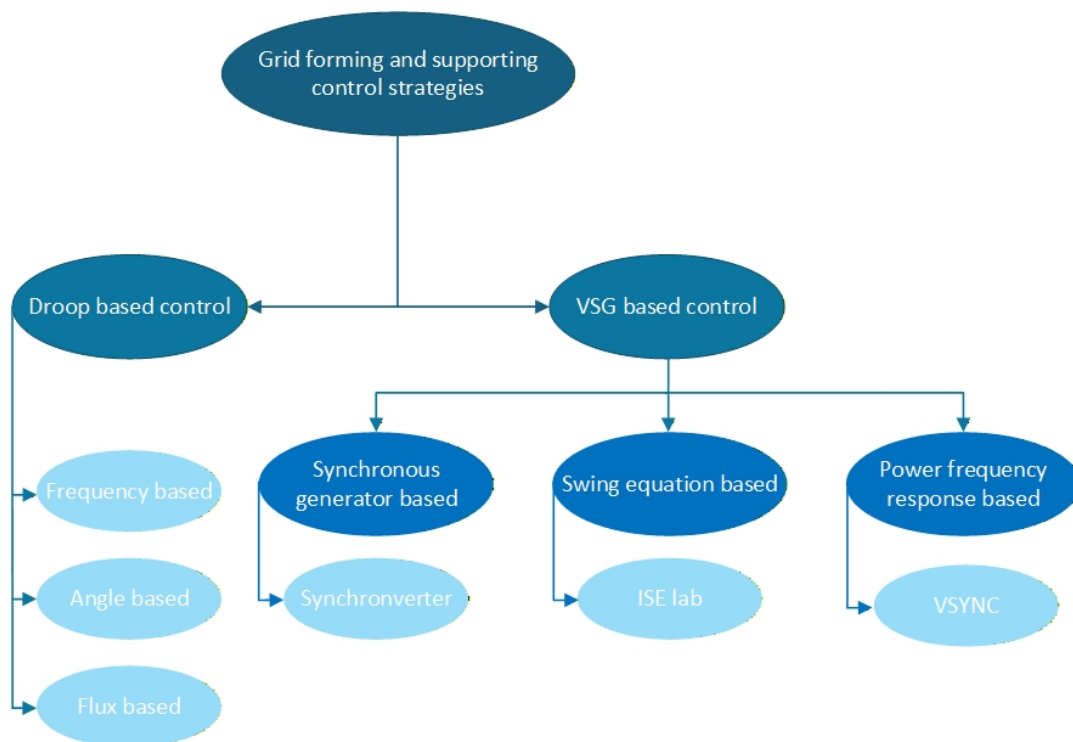


Figure 3.1: An overview of the grid forming and supporting control strategies

3.1. Grid-forming and Grid-following control

Inverter control strategies for VSCs are transitioning from grid-following (GFL) to grid-forming (GFM) control. This transition is driven by the need for grid-supporting capabilities, usually provided by the diesel generators, which are now being replaced with RES.

The GFL control strategies are designed such that the inverter operates as a current source extracting maximum power from RES [27]. To remain synchronized with the grid, GFL control tracks the grid voltage phasor rather than establishing its own. As a result, its reliance on existing grid conditions limits its ability to provide additional inertia and, consequently, frequency support to the grid [4]. It must be noted that research has explored grid-supporting control strategies for GFL converters, such as the VSYNC controller, which is covered in Chapter 3.3. However, this approach relies on frequency deviations and therefore provides inertia support only in response to changes in frequency rather than variations in power. Moreover, it requires frequency derivative measurements which are difficult to obtain in practice. This further illustrates the challenges associated with implementing effective inertia control in GFL converters [7].

Compared to GFL control, GFM control is designed so that the inverter operates as a voltage source. This enables the converter to set its own voltage phasor. Specifically, GFM control strategies, such as VSG control, use this capability to provide frequency support [14]. Hereby, the voltage phasor is set such that the converter can supply the required power to compensate for the frequency dip.

By setting their own voltage, GFM converters can also operate in islanded mode. To achieve this the converter must establish the grid voltage and frequency without being dependent on an existing grid. Using GFM control this is often done by mimicking the behavior of an SG. However, in GFL control this cannot be achieved as the setpoints are derived based on the grid measurements.

Furthermore, GFL control performs poorly in weak grids because it relies on a PLL for grid synchronization. According to [7], PLLs are known to exhibit instability in terms of frequency changes, voltage sags/swells, and harmonic distortion. In addition [14] mentions that the PLL structure loses stability in weak grids due to the asymmetric positive feedback mechanism. As a ship's microgrid is considered a weak grid, the instability issues of GFL control must be prevented.

GFM control addresses this by providing power synchronization without a PLL, hence bypassing instabilities caused by it. [24] introduces a power synchronization mechanism that mimics the power sharing capabilities of SGs for a GFM converter. [22] further mentions an improved synchronverter control strategy capable of synchronizing with the grid by itself without a dedicated synchronization unit. This would remove the non-linearity of the PLL improving the speed and accuracy of the synchronization. The ability of the GFM control to synchronize to the grid without a PLL makes it more applicable for weak grids.

3.2. The difference between droop control and VSG control

Droop control strategies utilize the steady state power sharing droop capabilities of an SG [7]. For multiple generators to operate together, conflicting frequency and voltage setpoints must be avoided. To ensure quick regulation this is achieved using P-f droop and Q-U droop. By tuning the frequency (f) or voltage (U) set points along a droop line with gradient equal to the droop coefficient, each generator sees the same frequency and output voltage and adjusts its active (P) and reactive (Q) power output accordingly. The active and reactive power droop equations are shown in 3.1 and 3.2 respectively, where θ is the voltage phase angle with θ_{set} the phase angle setpoint. V is the voltage amplitude, with V_{set} the voltage setpoint. k_p and k_q are the droop constants and P_m and Q_m are the measured active and reactive power which are first filtered with a low-pass filter before being sent to the controller. Reactive power control in both VSG and conventional droop control is based on Q-U droop, hence they exhibit the same behavior with respect to voltage regulation. Therefore, in this chapter, the comparison is focused on the active power control in P-f droop control and VSG control. Figure 3.2 illustrates the control structure of P-f droop control, where T is the low-pass filter time constant. From this figure it can be observed that the input to the controller is the measured active power P_m , while the output is the voltage phase angle θ . The frequency is inherently related to the phase angle, it can be obtained by taking the time derivative. Therefore, the droop mechanism effectively adjusts the system frequency through modulation of the voltage phase angle based on the measured active power.

$$\theta = \theta_{set} - k_p(P_m - P_{set}) \quad (3.1)$$

$$V = V_{set} - k_q(Q_m - Q_{set}) \quad (3.2)$$

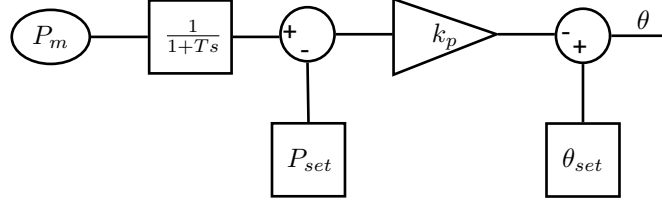


Figure 3.2: Standard P-f droop control

VSG control offers better frequency stabilization abilities than droop control. While droop control provides steady state frequency regulation, VSG control provides dynamic frequency support [26]. This distinction stems from the integration of the swing equation, the main principle governing the behavior of an SG, in VSG control. Consequently, droop control ensures that the correct steady state frequency is achieved, but may lead to frequency spikes due to sudden load changes, while VSG control, implemented using the swing equation, alters the frequency more smoothly. This results in an improved RoCoF and overall system stability [13].

Conversely, the presence of the swing equation in VSG control can lead to more oscillatory behavior in output power than using droop control. This is a common phenomenon in SGs, but is undesirable for converters as they have weaker overloading capabilities. Therefore, careful tuning of the damping and inertia factors is required in VSG control schemes [13].

Furthermore, [13] states and proves that droop control is a specific type of VSG control where the damping and inertia parameters (D and J) are set to zero. This further confirms that the steady state power sharing capabilities of droop and VSG control are the same if parameters are tuned correctly, but the dynamic performance differs as droop control provides no inertia or damping.

[2] further argues that inertia can be implemented in droop control as well by tuning the time constant of the low-pass filter and the droop coefficient. The time constant of the low-pass filter mimics the inertia in the swing equation, as both parameters filter frequency changes. Thus, by correctly tuning the time constant of the low pass filter, virtual inertia can be implemented. The droop coefficient emulates the damping characteristic of the swing equation and should be tuned inversely proportional to the damping constant. Therefore, by tuning the low-pass filter time constant and droop coefficient correctly, droop control can demonstrate the same characteristics as VSG control. In [13] inertia droop control is compared with VSG control for distributed generation sources connected via converters to the grid. From the results presented in Figure 13 of [13], it is evident that even with the added inertia to the droop control, VSG control still has a smoother change in frequency.

To conclude, standard droop control mimics the steady-state behavior of an SG, while VSG control also takes into account the transient behavior. Although droop control can also be tuned to provide damping and inertia support, VSG control is regarded as a more effective approach.

3.3. VSG control schemes

VSG-based control strategies emulate the dynamic and steady state characteristics of an SG to provide frequency support for the grid [14]. The control strategies can be divided into three main categories: synchronous generator based, swing equation based, and power-frequency response based. In this chapter one control strategy from each category is discussed and compared. Namely, the synchronverter, Ise's lab and VSYNC, respectively. Each VSG control strategy varies in complexity depending on the level of sophistication required for the system [26].

3.3.1. Synchronverter

The synchronverter controller is derived from the dynamic model of a round rotor synchronous machine. The eddy currents and magnetic saturation have been neglected for simplification. The basic dynamics of an SG are captured in Equations 3.3–3.5, where T_e is the output torque of the SG, M_f and i_f are the mutual inductance and current of the field windings which, when multiplied, represent the flux linkage λ_{fa} . Q is the reactive power output of the SG, e is the excitation voltage and θ is the angle between the rotor axis and one of the phases of the stator winding. The input voltage and current measured at PCC remains in the abc reference frame. The variables $\mathbf{i}$, $\cos(\theta)$ and $\sin(\theta)$ are given by Equation 3.6.

$$T_e = M_f i_f (\mathbf{i} \cdot \sin(\theta)) \quad (3.3)$$

$$e = \dot{\theta} M_f i_f \sin(\theta) \quad (3.4)$$

$$Q = -\dot{\theta} M_f i_f (\mathbf{i} \cdot \cos(\theta)) \quad (3.5)$$

$$\mathbf{i} = \begin{bmatrix} i_a \\ i_b \\ i_c \end{bmatrix} \quad \cos(\theta) = \begin{bmatrix} \cos(\theta) \\ \cos(\theta - \frac{2\pi}{3}) \\ \cos(\theta - \frac{4\pi}{3}) \end{bmatrix} \quad \sin(\theta) = \begin{bmatrix} \sin(\theta) \\ \sin(\theta - \frac{2\pi}{3}) \\ \sin(\theta - \frac{4\pi}{3}) \end{bmatrix} \quad (3.6)$$

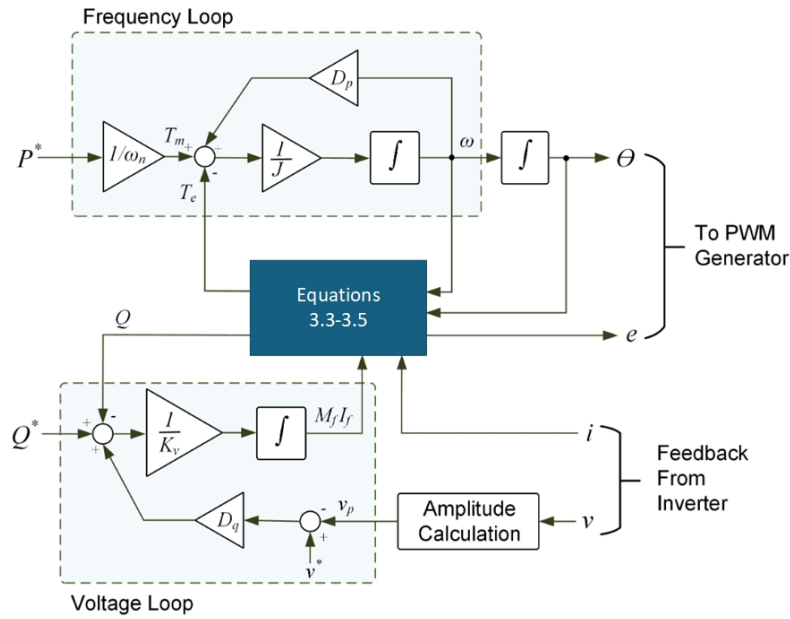


Figure 3.3: The synchronverter control scheme [26]

In Figure 3.3 the control of the synchronverter is summarized according to [26]. The voltage and current at PCC is measured and used as input for the control scheme. The control scheme consists of two main control loops, the frequency control loop and the voltage control loop which are coupled together. In the frequency control loop, the output torque T_e , calculated in Equation 3.3, is compared to the reference torque to determine the system frequency ω . The frequency is derived using the swing equation. By integrating the frequency reference, the voltage phase angle $\Theta = \theta_V$ is calculated and sent to the pulse generator.

The flux linkage $\lambda_{fa} = M_f i_f$ is calculated through the voltage control loop. The voltage control loop employs integral droop control, shown in Equation 3.10 to determine the required flux linkage for setting the excitation voltage to resolve the voltage and reactive power error. The excitation voltage is based on the flux linkage as evident from Equation 3.4. The reactive power error is derived by comparing the

reactive power Q calculated by Equation 3.5 to a setpoint Q^* . The voltage amplitude and phase angle setpoint are sent to the pulse generator.

3.3.2. Ise's lab

The Ise's lab controller strategy is a simplified version of the synchronverter mentioned above. Instead of modeling the SG fully, it mainly focuses on solving the swing equation to determine the frequency setpoint based on a power reference [7]. The swing equation is given by Equation 3.7. Where J is the moment of inertia or inertia coefficient, D_p is the damping constant, ω_m is the virtual angular frequency, ω_g is the grid frequency and P_{in} and P_{out} are the input and output power respectively.

$$P_{in} - P_{out} = J\omega_m \frac{d\omega_m}{dt} + D_p(\omega_m - \omega_g) \quad (3.7)$$

Using the swing equation, by comparing the reference power P_{in} to the measured power P_{out} the frequency setpoint can be derived. The damping characteristic $D_p(\omega_m - \omega_g)$ mimics the behavior of the damping windings in an SG. Both J and D_p need to be tuned based on the system requirements and behavior.

The voltage reference is set based on Q-U droop and varieties thereof, as is done by the AVR of an SG. The Q-U droop is derived from Equation 3.2 and shown in Equation 3.8. Equations 3.9 and 3.10 are varieties of this droop control, where V_{ref} is the reference voltage sent to the voltage control loop of the controller, k_{pq} and k_{iq} are the proportional and integral constants of the PI controller, k_u and k_q are the voltage and reactive power droop constants, Q_{set} and V_{set} are the reference reactive power and voltage respectively and Q_m and V_m are the measured reactive power and voltage respectively.

The standard droop control as shown in Equation 3.2 has low complexity and high stability. However, the steady state error is not resolved to zero. Thus, at higher loading conditions the voltage level lowers. To prevent this a PI controller can be used to resolve the voltage and reactive power error, whereby the integral term ensures zero steady state error [14]. This is shown in Equation 3.9. However, a PI controller is a stiff control, making it less applicable for a microgrid where multiple SGs and controllers must cooperate. Conversely, integral droop control, shown in Equation 3.10, ensures the steady state error is set to zero due to the integral and retains the power sharing capability of the droop controller, lending itself to parallel operation [24]. The integral droop controller is hence a more applicable reactive power controller for this application.

$$V_{ref} = [(V_{set} - V_m)k_u + Q_{set} - Q_m]k_q + V_{rated} \quad (3.8)$$

$$V_{ref} = (k_{pq} + \frac{k_{iq}}{s})[Q_{set} - Q_m + (V_{set} - V_m)k_u] + V_{rated} \quad (3.9)$$

$$V_{ref} = \frac{k_q}{s}[Q_{set} - Q_m + (V_{set} - V_m)k_u] + V_{rated} \quad (3.10)$$

The behavior of an SG is thus emulated using the swing equation and Q-U integral droop. The swing equation mimics the physics of the SG and sets the frequency reference for the grid converter. The Q-U droop mimics the behavior of the AVR of an SG and sets the output voltage of the converter.

3.3.3. VSYNC

As briefly touched upon in Chapter 3.1, the VSYNC control scheme is developed to implement additional grid support for a GFL converter. The VSYNC control is the most simple control scheme, because it does not include the complex equations used to mimic an SG, but instead solely mimics the inertial response of an SG [7]. In this scheme, the converter is seen as a current source which adjusts its output based on frequency variations in the system [14]. The current reference for the grid converter is based on the reference power. The power reference is set by Equation 3.11. Where, K_D and K_I are the damping constant and inertia coefficient and $\Delta\omega$ and $\frac{d\Delta\omega}{dt}$ are the change in angular frequency and RoCoF respectively.

$$P_{VSG} = K_D \Delta\omega + K_I \frac{d\Delta\omega}{dt} \quad (3.11)$$

The control scheme can be seen as a droop control with a derivative term, employed to minimize the frequency fluctuation. The damping coefficient K_D ensures the system reaches steady state. The frequency derivative term ensures that the system can provide quick dynamic frequency response. The change in frequency and RoCoF is measured using a PLL.

3.3.4. Comparison

The main advantage of the VSYNC control strategy is that it is a relatively simple control strategy. This makes it easy to implement. In addition, it controls the converter current, which means it has inherent over current protection. However, one of the biggest flaws of this control strategy is that it is not a grid forming control strategy. It therefore cannot set its own grid and relies on a PPL to synchronize with the grid. As mentioned in Chapter 3.1 using a PPL deteriorates the stability of the system. Furthermore, because the control strategy uses a frequency derivative, it is also susceptible to noise. Due to the above mentioned points this control strategy is not suitable for application on a shipboard microgrid.

The synchronverter and Ise's lab strategy are both grid-forming. They have their own power synchronization loop, bypassing the disadvantages of a PPL and can work in islanded mode. The main difference between the two control strategies is their complexity. The synchronverter is more complex, which can lead to numerical instability. Furthermore, the voltage and frequency control loops are coupled, which makes it difficult to control them separately. In contrast, Ise's lab strategy implements decoupled control loops for voltage and frequency and has a simpler implementation. While this approach requires precise tuning of the swing equation coefficients to prevent power, hence frequency, oscillation, its simplicity and effectiveness makes it well suited for a shipboard microgrid. Specifically the Ise's lab strategy with the integral droop voltage control provides the robust response necessary for a weak grid.

4

Description of the microgrid

This chapter focuses on modeling the DC ESS, the converter and the connected microgrid to analyze their steady state response. It is essential to model the behavior of the system to design and tune the controller effectively.

4.1. Model of the microgrid

The system is simplified and modeled in Figure 4.1. The ESS is modeled by a DC voltage source. The inverter is a three-phase, 6 pulse inverter, whose output is filtered using an LCL filter. The system is connected at the PCC to the rest of the grid. For now, the grid is assumed to be an infinite bus and can therefore be represented by an ideal voltage source and a series impedance. An overview of the system parameters can be found in Table 4.1.

Parameter	L_{f1}	L_{f2}	C_f	L_g	R_g	Rated power	Grid voltage ($V_{LL,rms}$)	Grid Frequency	ESS Voltage (V_{dc})
Value	$569 \mu H$	$376 \mu H$	$61 \mu F$	$3 mH$	0.18Ω	85 kVA	400 V	50 Hz	600 V

Table 4.1: system parameters

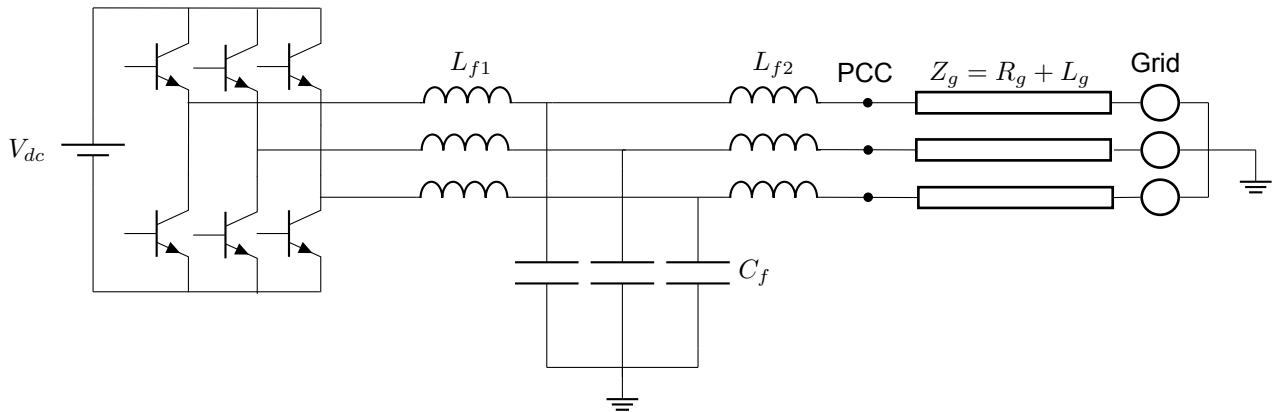


Figure 4.1: Simplified system model including the ESS modeled by a DC voltage source and the microgrid modeled with a line impedance and an ideal voltage source

4.1.1. State-space representation

The equivalent circuit of the system represented in Figure 4.1 is shown in Figure 4.2. The system can now be described using three simple equations as shown in Equations 4.1–4.3. V_{dc} is the DC voltage of the ESS, i and V are the output current (A) and voltage (V) of the converter, C_f , L_{f1} and L_{f2} are the capacitance (F) and inductances (H) of the LCL filter, Z_g is the grid impedance, with R_g the grid

resistance (Ω) and L_g the grid inductance (H). U_f is the voltage (V) across the capacitor, i_g is the current (A) to the grid and E is the grid voltage (V).

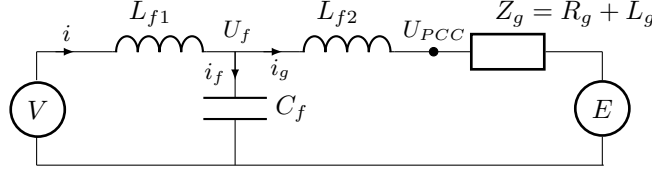


Figure 4.2: The model from Figure 4.1 simplified

$$\frac{di}{dt} L_{f1} = V - U_f \quad (4.1)$$

$$\frac{dU_f}{dt} C_f = i - i_g \quad (4.2)$$

$$\frac{di_g}{dt} (L_{f2} + L_g) + i_g R_g = U_f - E \quad (4.3)$$

The parameters from Equation 4.1–4.3 are mapped from the stationary frame to the rotating dq reference frame. For this, the system's phase angle is used to align the dq reference frame with the grid, such that the control variables are synchronized with the grid frequency. Due to this transformation and the derivative terms, the d- and q- axis components are coupled to each other with the grid frequency ω_g . Equation 4.4 shows how the derivative of a measurement in a rotating reference frame leads to coupled d- and q-components. How this coupling is established is mathematically derived in Appendix A.

$$\dot{X}_d = X_d + \omega_g X_q \text{ and } \dot{X}_q = X_q - \omega_g X_d \quad (4.4)$$

The system is formulated into the state-space model of Equation 4.6 by combining Equations 4.1–4.3 and incorporating the dq-frame cross-coupling terms derived in Equation 4.4. A state-space model is defined in Equation 4.5. Where $\dot{x}(t) = \mathbf{A}x(t) + \mathbf{B}u(t)$ is given by Equation 4.6, matrix $\mathbf{C}$ is given by Equation 4.7 and $\mathbf{D} = 0$. Furthermore, a subscript d indicates a d-axis component and a subscript q indicates a q-axis component.

$$\dot{x}(t) = \mathbf{A}x(t) + \mathbf{B}u(t) \quad y = \mathbf{C}x(t) + \mathbf{D}u(t) \quad (4.5)$$

$$\begin{bmatrix} \dot{i}_d \\ \dot{i}_q \\ \dot{U}_{fd} \\ \dot{U}_{fq} \\ \dot{i}_{gd} \\ \dot{i}_{gq} \end{bmatrix} = \begin{bmatrix} 0 & \omega_g & \frac{-1}{L_{f1}} & 0 & 0 & 0 \\ -\omega_g & 0 & 0 & \frac{-1}{L_{f1}} & 0 & 0 \\ \frac{1}{C_f} & 0 & 0 & \omega_g & \frac{-1}{C_f} & 0 \\ 0 & \frac{1}{C_f} & -\omega_g & 0 & 0 & \frac{-1}{C_f} \\ 0 & 0 & \frac{1}{L_{f2}+L_g} & 0 & \frac{-R_g}{L_g+L_{f2}} & \omega_g \\ 0 & 0 & 0 & \frac{1}{L_{f2}+L_g} & -\omega_g & \frac{-R_g}{L_g+L_{f2}} \end{bmatrix} \begin{bmatrix} i_d \\ i_q \\ U_{fd} \\ U_{fq} \\ i_{gd} \\ i_{gq} \end{bmatrix} + \begin{bmatrix} \frac{1}{L_{f1}} & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{L_{f1}} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & \frac{-1}{L_{f2}+L_g} & 0 & 0 & 0 \\ 0 & 0 & 0 & \frac{-1}{L_{f2}+L_g} & 0 & 0 \end{bmatrix} \begin{bmatrix} V_d \\ V_q \\ E_d \\ E_q \\ 0 \\ 0 \end{bmatrix} \quad (4.6)$$

$$\mathbf{C} = \begin{bmatrix} 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \end{bmatrix} \quad (4.7)$$

4.1.2. Transfer function

From the state-space model the transfer function is derived using Equation 4.8, where matrices A and B are given in Equation 4.6, matrix C is given in Equation 4.7, $D = 0$ and I is the identity matrix. The cross-coupling between the d- and q-axis is neglected by setting ω_g to zero. This simplifies the systems response and is justified as the system gets decoupled in the controller as well. How the d- and q-axis are decoupled is explained in Chapter 5.1. The transfer function of the system is given in Equation 4.9.

$$H(s) = \frac{Y(s)}{U(s)} = C(sI - A)^{-1}B + D \quad (4.8)$$

$$H(s) = \frac{i_d}{V_d} = \frac{1 + C_f R_g s + C_f L_{f2} s^2 + C_f L_g s^2}{R_g + (L_{f1} + L_{f2} + L_g)s + C_f L_{f1} L_{f2} s^3 + C_f L_{f1} R_g s^2 + C_f L_{f1} L_g s^3} \quad (4.9)$$

4.2. Response of the microgrid

Now that the state-space matrices and transfer function of the system are defined, the system response can be calculated. From the transfer function the bode plot, more specifically the magnitude response, is calculated and from the state-space matrices the time domain response of the system is calculated. Both are calculated in MATLAB.

The magnitude plot shows the system's output response i_d to the input V_d at different frequencies and is shown in Figure 4.3. At two frequencies the gain of the system spikes, namely at 5801 rad/s, where there is a positive gain peak, and at 2202 rad/s, where there is a negative gain peak. These are the resonant and anti-resonant peaks respectively. The frequency at which the resonant peak occurs ω_{res} , also referred to as the resonance frequency, is calculated using Equation 4.10 and the frequency at which the anti-resonance peak occurs ω_0 , also referred to as the anti-resonance frequency, is calculated using Equation 4.11. The bandwidth must be constrained to avoid the resonance frequency as converter harmonics are amplified at this frequency [31]. The initial gain $|H(0)|$ of the system is derived in Equation 4.12 by setting the frequency component in the transfer function to zero and converting the result to decibels.

$$\omega_{res} = \frac{L_{f1} + L_{f2} + L_g}{\sqrt{L_{f1} \cdot (L_{f2} + L_g) \cdot C_f}} = 5801 \text{ rad/s} \quad (4.10)$$

$$\omega_0 = \frac{1}{\sqrt{(L_{f2} + L_g) \cdot C_f}} = 2202 \text{ rad/s} \quad (4.11)$$

$$|H(0)| = 20 \log\left(\frac{1}{R_g}\right) \quad (4.12)$$

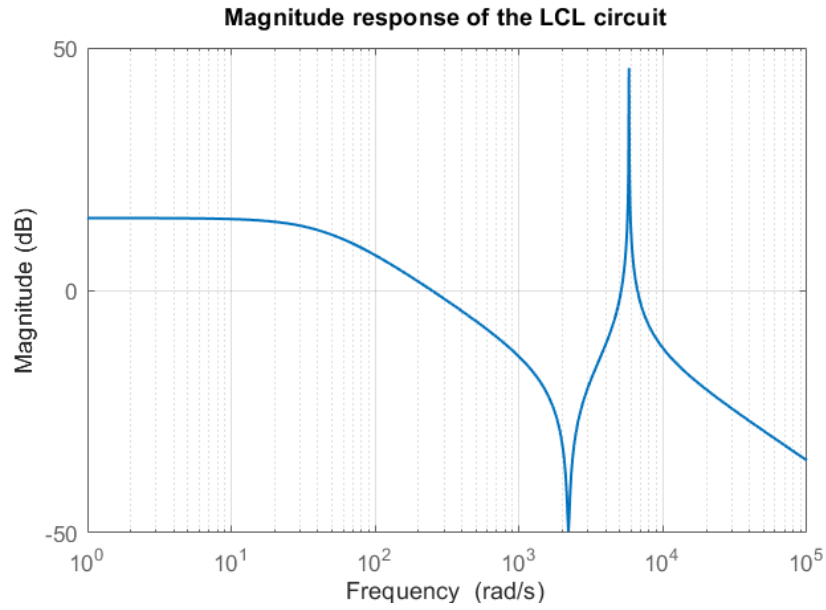
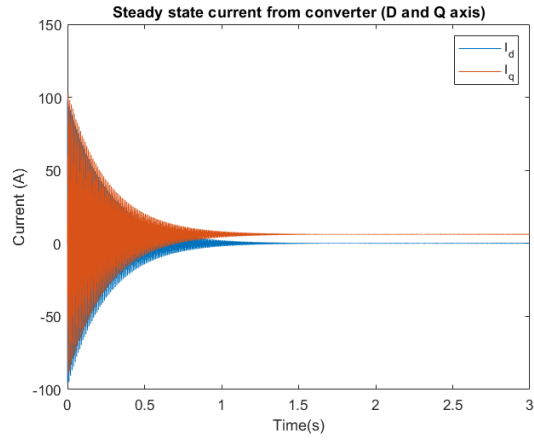


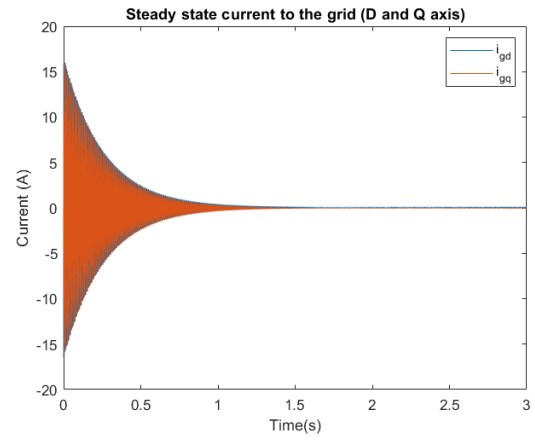
Figure 4.3: The magnitude response of the system represented in Figure 4.2

Besides the frequency response, the time-domain steady state response of the system is also important to take into consideration. The steady state response of the system given by input 4.13 is shown in Figure 4.4. In Chapter 6 this response is compared to the simulation results to determine whether the controller is tuned correctly.

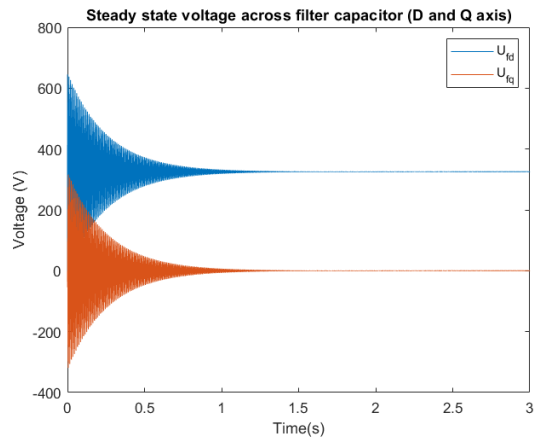
$$\begin{bmatrix} V_d \\ V_q \\ E_d \\ E_q \\ 0 \\ 0 \end{bmatrix} = \begin{bmatrix} 324.2 \\ 0.085 \\ 230 \cdot \sqrt{3} \\ 0 \\ 0 \\ 0 \end{bmatrix} \quad (4.13)$$



(a) The steady state current from the converter at input conditions given by Equation 4.13



(b) The steady state current to the grid at input conditions given by Equation 4.13



(c) The steady state voltage across the filter capacitor at input conditions given by Equation 4.13

Figure 4.4: Steady state response of the system

Implementation and tuning of VSG

This chapter will walk through the process of developing and tuning the controller for the VSC connected to the system analyzed in Chapter 4. The overall structure of a controller, represented in Figure 2.4 is adapted for the specific VSG control scheme and presented in Figure 5.1. The controller is based on the VSG implementation in [4] and adapted and tuned specifically for a shipboard microgrid.

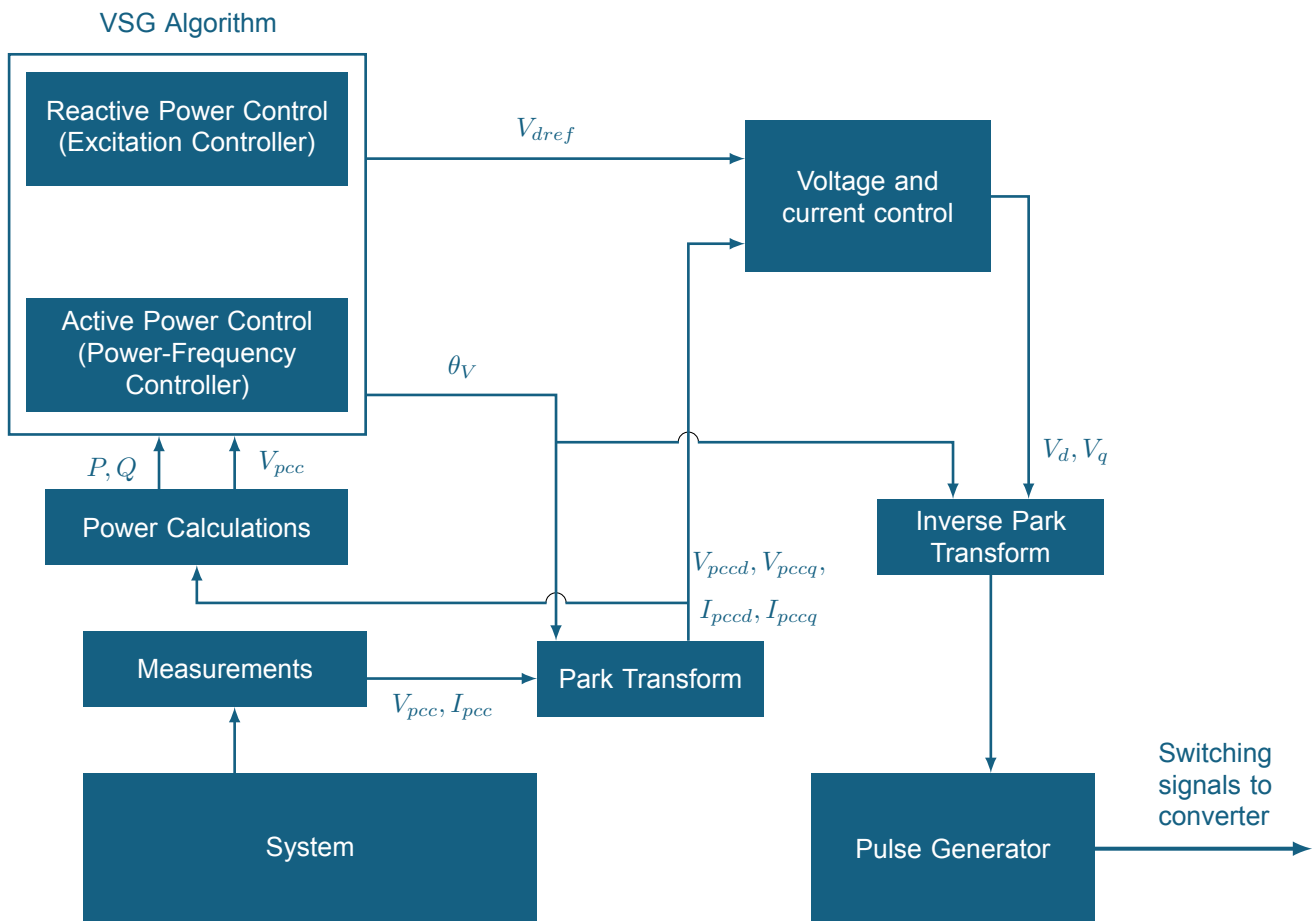


Figure 5.1: An overview of the proposed controller with VSG control

5.1. Voltage and current control

The most inner control loops, namely, the voltage and current control is represented in Figure 5.2. Firstly, in block a_1 the voltage error is derived through subtracting the reference voltage (V_{dref} and V_{qref}) by the measured voltage at the point of common coupling (V_{pccd} and V_{pccq}). This is done separately for both the d- and q- axis. Then using a PI controller the required current I^* is determined to set the voltage error to zero. In block a_2 the same principle is applied to determine the reference voltage V^* . Added to the reference values V^* and I^* is a virtual impedance indicated by block b in Figure 5.2. The virtual impedance decouples the d- and q-axis components such that each axis can be controlled separately. Otherwise, a transient on one axis will influence the other axis, which is undesirable [30]. How the virtual impedance is derived is shown in Appendix B.

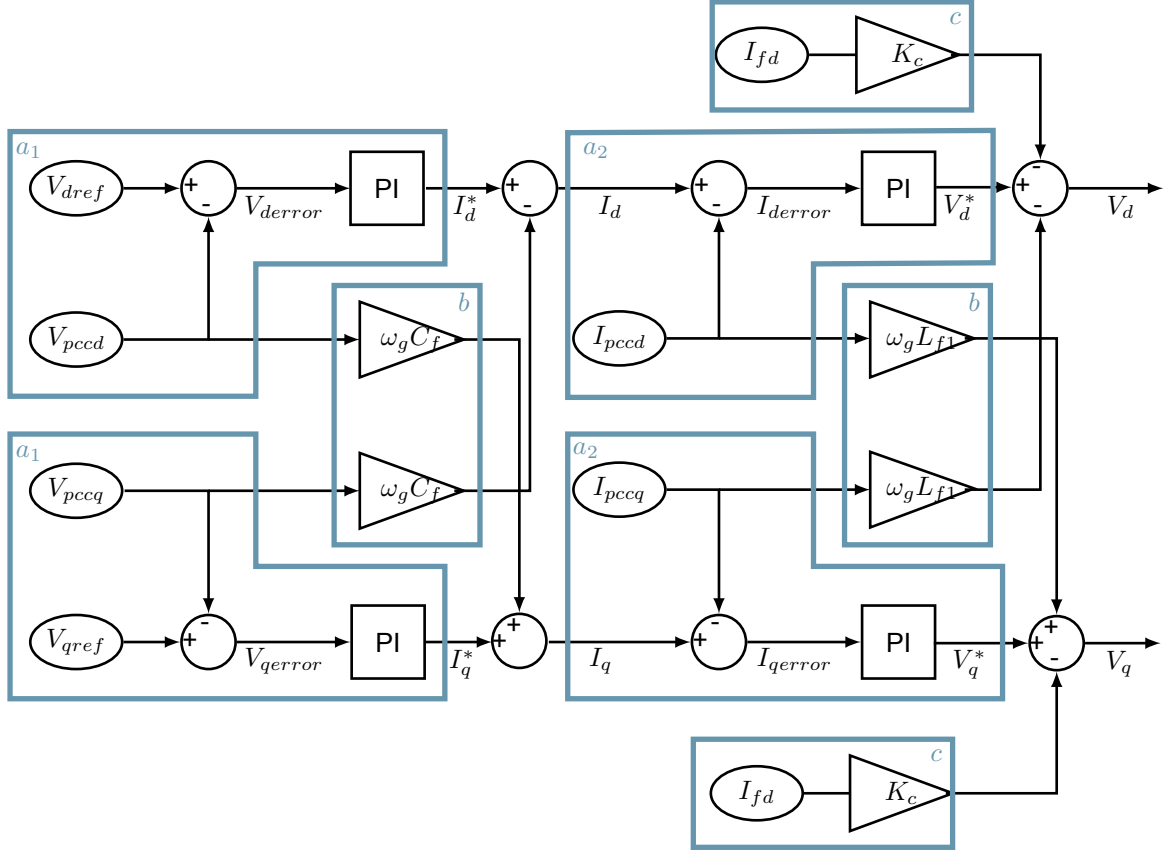


Figure 5.2: The voltage and current control scheme, with error control (a), virtual impedance (b) and a virtual damping resistor (c)

To derive the voltage setpoints V_d and V_q , an additional virtual damping resistance term is added to the reference value V^* (see Figure 5.2 block c). Here i_{fd} and i_{fq} are the currents through the capacitor of the LCL filter on the d- and q-axis respectively. Shown in Figure 5.3, this additional input acts as a virtual damping resistor, with resistance K_c , to dampen the oscillations around the resonance frequency of the LCL filter [4]. Placing a physical resistor would mean more losses in the system, which is why it is often done virtually [23]. The control signals shown in diagram 5.2, are shown algebraically in Equations 5.1–5.4.

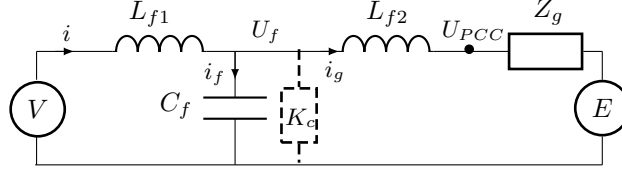


Figure 5.3: The symbolic virtual resistor represented in the controller by block c in Figure 5.2

$$V_d = V_d^* - \omega_g L_{f1} i_{pccd} - i_{fd} k_c \quad (5.1)$$

$$V_q = V_q^* + \omega_g L_{f1} i_{pccq} - i_{fq} k_c \quad (5.2)$$

where $V_d^* = \frac{k_p s + k_i}{s} (i_d - i_{pccd})$ and $V_q^* = \frac{k_p s + k_i}{s} (i_q - i_{pccq})$. Where k_p is the proportional constant of the PI controller (V/A) and k_i is the integral constant of the PI controller (V/(A · s)).

$$i_d = i_d^* - \omega_g C_f V_{pccd} \quad (5.3)$$

$$i_q = i_q^* + \omega_g C_f V_{pccq} \quad (5.4)$$

where $i_d^* = \frac{k_p s + k_i}{s} (V_{dref} - V_{pccd})$ and $i_q^* = \frac{k_p s + k_i}{s} (V_{qref} - V_{pccq})$. Where k_p is the proportional constant of the PI controller (A/V) and k_i is the integral constant of the PI controller (A/(V · s)).

5.1.1. Tuning the PI controller

To achieve the correct response of the system the PI controller must be tuned correctly. By tuning the PI controller parameters, the poles and zeros of the system's transfer function are adjusted to achieve the desired response. The system's transfer function provided by Equation 4.8 is a complex third order system which is difficult to tune. Therefore, the system must first be simplified.

Firstly, because the frequency of the system is relatively low (50 Hz), the capacitor can be considered an open circuit. Secondly, because the switching frequency of the inverter is a lot faster than the grid frequency, the grid voltage can be considered zero. This simplifies the circuit to Figure 5.4. Now the transfer function of this system is that of a standard RL circuit (see Equation 5.5). Where R_g is the grid resistance and L_{eq} is the equivalent inductance thus, $L_{eq} = L_{f1} + L_{f2} + L_g$

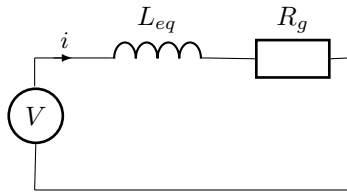


Figure 5.4: The circuit in Figure 4.2 simplified further to tune the PI controller

$$P(s) = \frac{V_d}{i_d} = \frac{1}{L_{eq}s + R_g} \quad (5.5)$$

The response of this system is shown in Figure 5.6a. Ideally, the response has a unity (0dB) gain at low frequencies and a -3dB attenuation at the cut-off frequency. However, as evident in Figure 5.6a, the uncompensated system deviates from this behavior. Specifically, at low frequency the gain is governed by Equation 4.12. Fortunately, the desired closed loop response can be achieved by tuning the PI controller. More specifically, this is done by tuning the open loop transfer function of the system,

using the pole-zero cancellation method [19]. The open loop system is represented in Figure 5.5, where the PI controller transfer function is shown in Equation 5.5 and the system transfer function is shown in Equation 5.6. By tuning the proportional constant according to Equation 5.8 and the integral constant according to Equation 5.7, the response of the system is governed by the transfer function shown in Equation 5.9. The cut-off frequency, thus the bandwidth of the current control loop is set to $\omega_c = 1750$ rad/s. This bandwidth ensures the system has a fast settling time, while still being small enough to filter out noise of the signal and avoid the resonance frequency of the LCL filter. The outer voltage control loop is scaled with a bandwidth a factor 10 smaller. This allows the inner control loop to settle faster than the voltage reference changes. The inner loop can now be treated as unity gain from the perspective of the slower outer loop [11]. Figure 5.6b shows the closed loop magnitude response of the PI controlled system and illustrates that the output is not attenuated until the cut-off frequency. This is evident by the 0 dB gain up until 1750 rad/s, where the -3db gain is reached.

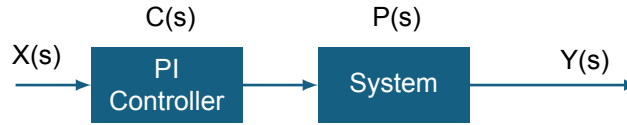


Figure 5.5: Definition of an open loop system

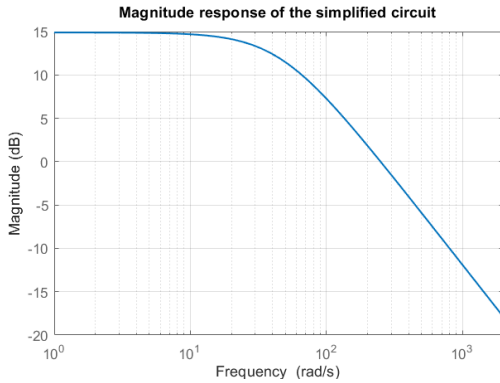
$$C(s) = \frac{k_p s + k_i}{s} \quad (5.6)$$

Where k_p and k_i are the proportional and integral gain respectively.

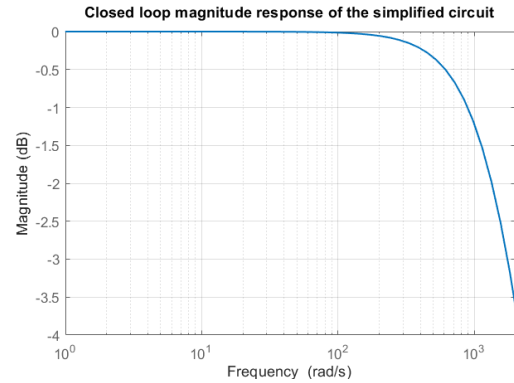
$$k_i = \omega_c R_g \quad (5.7)$$

$$k_p = \omega_c L_{eq} \quad (5.8)$$

$$H(s) = C(s) \cdot P(s) = \frac{k_p s + k_i}{s(L_{eq}s + R_g)} = \frac{\omega_c}{s} \quad (5.9)$$



(a) The response of the simple RL circuit without PI control



(b) The closed loop response of the simple RL circuit with PI control

Figure 5.6: The magnitude response of the system with and without PI controller

5.2. Active and Reactive power control

The active and reactive power of the system is controlled by setting the converter output voltage magnitude and phase angle. To understand how the output voltage of the converter determines the power setpoints, consider a simplified system where a purely inductive reactance connects the PCC and the grid as shown in Figure 5.7. Aligning the phasor reference frame with the grid voltage sets the grid voltage angle θ_g to zero and Equation 5.12 holds. Consequently, the active and reactive power across

the reactance is governed by Equation 5.10. Where V_{pcc} is the output voltage of the converter at PCC, E is the grid voltage, δ is the load angle as given by Equation 5.11 and X is the load impedance, $j\omega_g L$. In the control loop the reactive power is set to a reference of 0, therefore the following condition must hold $V_{pcc} = E$. In other words, by setting the voltage at PCC V_{pcc} equal to the grid voltage E the reactive voltage drop across the reactance is eliminated, minimizing the reactive power exchange. The active power delivered by the load can then be determined by setting the load angle of the system δ . As evident from Equation 5.11, the load angle is dependent on the inverter voltage phase angle θ_{VSG} , and the grid voltage phase angle θ_g . The grid voltage phase angle cannot be influenced by the controller. However, by adjusting the converter output voltage phase angle with the active power control loop in this VSG implementation, θ_{VSG} can be set to achieve the desired active power response. Thus, the required active power is delivered by setting the converter voltage phase angle relative to the grid. Hence, aligning the grid voltage phasor with the reference frame such that θ_g is zero is justified.

$$P = \frac{V_{pcc}E \sin(\delta)}{X} \quad Q = \frac{E^2 - V_{pcc}E \cos(\delta)}{X} \quad (5.10)$$

$$\delta = \theta_{VSG} - \theta_g \quad (5.11)$$

By choosing the reference frame such that angle $\theta_g = 0$ the equation becomes

$$\delta = \theta_{VSG} \quad (5.12)$$

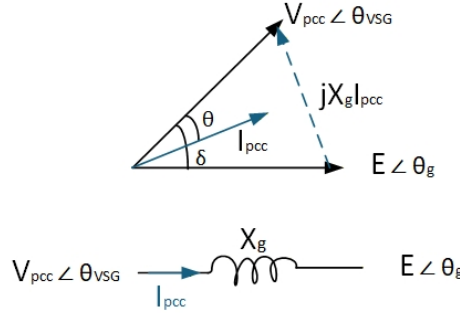


Figure 5.7: The phasor of the voltage across an inductance

The reactive power control loop mimics the behavior of the AVR of an SG. As explained in section 3.3, for this controller the integral droop control is used to set the required output voltage. The control loop of the reactive power is shown in Figure 5.8, with the corresponding constants shown in Table 5.1. V_{pcc} is calculated according to Equation 5.13.

$$V_{pcc} = \sqrt{V_d^2 + V_q^2} \quad (5.13)$$

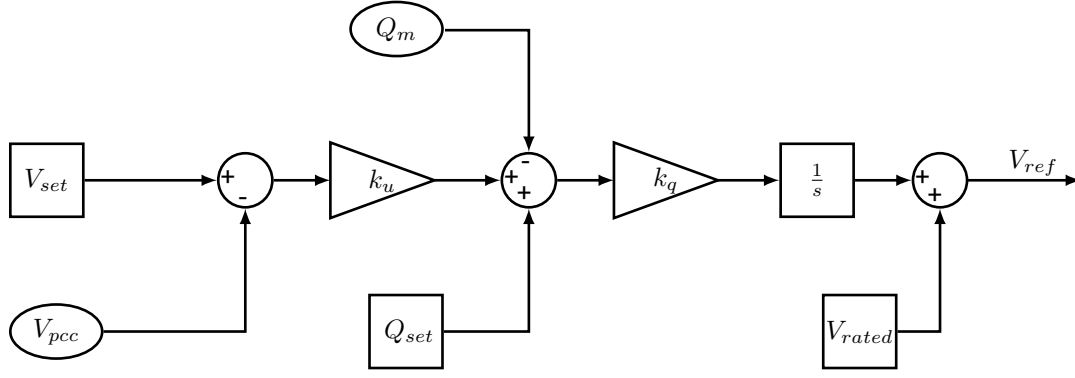


Figure 5.8: The reactive power control loop of the VSG implementation

The frequency of the system changes based on an imbalance between power supply and demand according to the swing equation. This concept is used in the active power control loop. The swing equation, equation 3.7, is re-written for clarity in Equation 5.14, P_{ref} and P_m are the reference and measured power respectively, in Watts. ω_{VSG} and ω_g are the frequency set by the VSG and the grid frequency in rad/s. J is the inertia coefficient in $\text{kg} \cdot \text{m}^2$ and D is the damping constant in $\text{N} \cdot \text{m} \cdot \text{s/rad}$. The output of this differential equation is the frequency deviation $\omega_{VSG} - \omega_g = \Delta\omega$ required to stabilize the power difference $P_{ref} - P_m = \Delta P$. This loop is shown up until point 'A' in Figure 5.9. To derive the load angle from this frequency deviation, first the grid frequency is added, (see Figure 5.9 point 'B') which then determines the new frequency setpoint ω_{VSG} . Then according to Equation 5.15 the phase angle is calculated by integrating the frequency at point 'C'.

$$J \frac{d(\omega_{VSG} - \omega_g)}{dt} = \frac{P_{ref} - P_m}{\omega_g} - D(\omega_{VSG} - \omega_g) \quad (5.14)$$

$$\frac{d\delta}{dt} = \omega_{VSG} \quad (5.15)$$

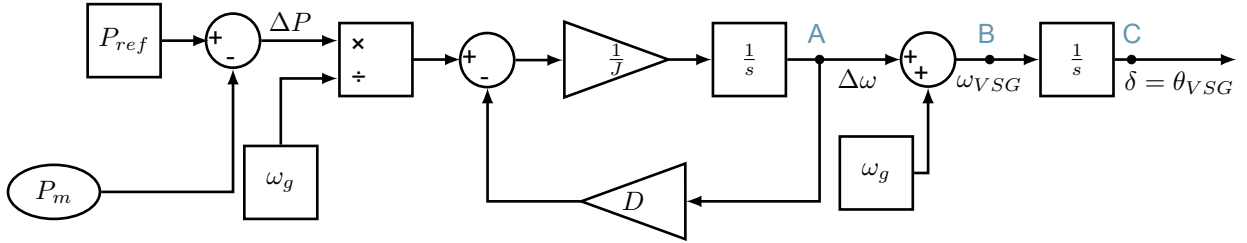


Figure 5.9: The active power control loop of the VSG implementation

5.2.1. Modeling the power control loop

To model the behavior of the grid in response to the power control loop the synchronizing power coefficient should be taken into account. The synchronizing power coefficient defines the stiffness of the grid. In other words it quantifies the sensitivity of power output, ΔP , based on the change in load angle $\Delta\delta$. Equation 5.16 shows how the synchronizing power coefficient is calculated, where V_{inv} is the output voltage of the converter at PCC, V_{grid} is the grid voltage, L_g is the grid impedance between the converter at PCC and the grid and δ is the load angle as given in Equation 5.12.

Assuming steady state operation, the load angle deviation $\Delta\delta$ is relatively small so $\cos(\delta)$ can be considered 1. The amplitude invariant Park transform is used, which is why the factor $\frac{3}{2}$ is present. Furthermore, it is assumed that $V_{inv} = V_{grid} = 230 \cdot \sqrt{2} = 325 \text{ V}$. Plugging these values into Equation 5.16 results in $S_p = 168,110 \text{ W/rad}$.

The power control loop with the system response can now be represented by the differential Equation 5.17. With $\Delta P = P_{ref} - P_m$, $\Delta\omega = \omega_{VSG} - \omega_g$ and $\omega_{VSG} = \frac{d\delta}{dt}$ and S_p is the synchronizing power coefficient. The full response of the system is important for tuning the damping and inertia coefficients and for determining the reference power.

$$S_p = \frac{\Delta P}{\Delta\delta} = \frac{d}{d\delta} \left[\frac{3V_{inv}V_{grid}}{2\omega_g L_g} \sin(\delta) \right] = \frac{3V_{inv}V_{grid}}{2\omega_g L_g} \cos(\delta) \quad (5.16)$$

$$\frac{d\Delta\omega_{VSG}}{dt} + \frac{S_p \Delta\delta}{\omega_g J} = \frac{\Delta P}{J\omega_g} - D\Delta\omega_{VSG} \quad (5.17)$$

The small signal dynamic behavior is characterized by the state-space model in Equation 5.18. Where $\Delta\omega$ represents the frequency deviation, $\Delta\delta$ the load angle, hence phase angle deviation and δ the absolute phase angle, which is used to synchronize the control to the grid. The steady state time domain response based on the inputs in Equation 5.19 is shown in Figure 5.10.

In Figure 5.10a, it can be observed that $\Delta\delta$ does not converge to zero, but instead reaches a steady state value at $5.9486 \cdot 10^{-6} = \frac{1}{S_p}$. This is consistent with the systems response, which is given by $\frac{\Delta\delta}{\Delta P}$ and corresponds to the inverse of the synchronization power coefficient. In contrast, the frequency deviation $\Delta\omega$ converges to zero, indicating no steady state frequency error. The angle provided to the Park transformation block for synchronization, varies between 0 and 2π every $\frac{1}{f} = 0.02$ seconds, as illustrated in Figure 5.10b.

$$\begin{bmatrix} \dot{\Delta\omega} \\ \dot{\Delta\delta} \\ \dot{\delta} \end{bmatrix} = \begin{bmatrix} -\frac{D}{J\omega_g} & -\frac{S_p}{\omega_g J} & 0 \\ 1 & 0 & 0 \\ 1 & 0 & 0 \end{bmatrix} \begin{bmatrix} \Delta\omega \\ \Delta\delta \\ \delta \end{bmatrix} + \begin{bmatrix} \frac{1}{J\omega_g} & 0 & 0 \\ 0 & 0 & 0 \\ 0 & 1 & 0 \end{bmatrix} \begin{bmatrix} \Delta P \\ \omega_g \\ 0 \end{bmatrix} \quad (5.18)$$

$$\begin{bmatrix} \Delta P \\ \omega_g \\ 0 \end{bmatrix} = \begin{bmatrix} 1 \\ 2\pi f \\ 0 \end{bmatrix} \quad (5.19)$$

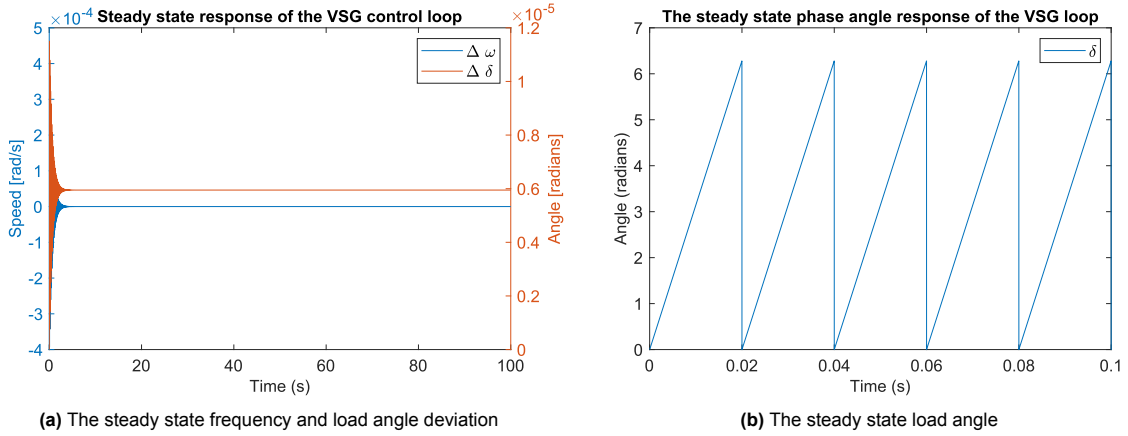


Figure 5.10: The steady-state response of the frequency deviation, load angle deviation and load angle

5.2.2. Setting the reference power

The active power control loop compares the measured power to a reference value. This reference value P_{ref} needs to be set correctly. There are two scenarios in which the converter needs to operate as outlined in Chapter 2.1.1. Each scenario requires a different reference power.

First, the power reference for the converter operating in islanded mode is derived. To ensure the system operates at a constant frequency, the reference power for the power control loop should change

depending on a change in load. A change in load is detected by a change in frequency. To determine a change in frequency the measured frequency is compared to the desired setpoint frequency. To determine the power required to resolve the frequency error, the PI controller is tuned based on the transfer function $\frac{\Delta P}{\Delta \omega}$. This is given in Equation 5.20. The control loop can be seen in Figure 5.11, where ω_m is the measured frequency.

$$\frac{\Delta P}{\Delta \omega} = \frac{s}{s^2 + \frac{D_p}{J\omega_g} + \frac{S_p}{\omega_g J}} \quad (5.20)$$

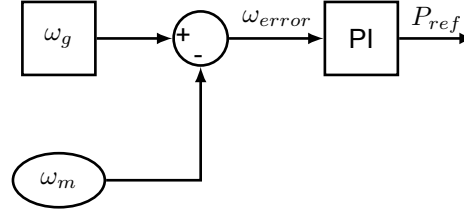


Figure 5.11: Control to determine the reference power based on the frequency error

To tune the PI controller the repeated pole tuning method is used to account for the zero in the numerator of the transfer function. The repeated pole tuning method tunes the closed loop response of the system. The closed loop system is shown in Figure 5.12. The transfer function of the closed loop response is given by Equation 5.21. The desired response of a second order transfer function with cut-off frequency ω_c rad/s is given by Equation 5.22. By equating the denominators of Equation 5.21 and 5.22 the PI constants can be set. The PI constants are shown in Equations 5.23. The cut-off frequency is taken to be 500 rad/s.

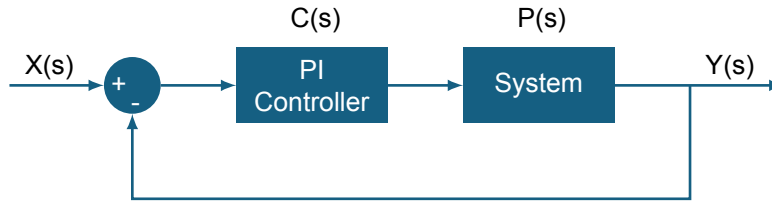


Figure 5.12: Definition of a closed loop system

$$\frac{Y(s)}{X(s)} = H(s) = \frac{C(s)P(s)}{1 + C(s)P(s)} = \frac{k_p s + k_i}{s^2 + (\frac{D_p}{J\omega_g} + k_p)s + k_i + S_p} \quad (5.21)$$

$$H(s) = \frac{1}{s^2 + 2\omega_c s + \omega_c^2} \quad (5.22)$$

$$k_i = \omega_c^2 J \omega_g - S_p = 7.6857 \cdot 10^6 \quad k_p = 2\omega_g J \omega_c - D_p = 3.1416 \cdot 10^4 \quad (5.23)$$

In grid-connected mode, the purpose of the VSC connected ESS is now to only compensate during transient load changes. The ESS should therefore not supply any power during steady state. The reference power is hence set to 0 kW. For this scenario the SG is assumed to be in isochronous control with the frequency set at 50 Hz. When the load increases, the converter temporarily delivers the required power to stabilize the system frequency at 50 Hz, effectively mimicking the natural inertial response of the swing equation. Due to its superior dynamic response time, the converter handles the transient power deficit. However, once the frequency stabilizes, the SG supplies the steady-state load demand, allowing the converter's active power output to return to zero

5.3. Discretizing the control

The last step in the process is to discretize the system to facilitate digital control implementation. This was achieved using the trapezoidal method, as defined in Equation 5.24. This method preserves the stability of the system [10]. In this equation Z and s indicate the discrete z -domain and the continuous laplace domain variables respectively and T_s denotes the sampling time. The sampling time is limited to $250 \mu\text{s}$, which corresponds to the shortest sampling period available in the Crealizer™. Integration blocks represented by $\frac{1}{s}$ in the continuous laplace domain are expressed in discrete form, as shown in Equation 5.25.

Furthermore, when converting the system from a continuous to discrete time domain it is important to introduce delay blocks in signal paths. Specifically, delay blocks are added between the signals sent from the control to the converter and between the feedback signals from a closed-loop system. These delays ensures that the control action is based on previously sampled data, preventing signal updates and measurements to occur simultaneously. Consequently, a delay of one sampling period is introduced.

To determine the effect of discretizing the system on its response the bode plots are compared. The bode plot of the full LCL model both in the discrete and continuous time domain are shown in Figure 5.13. It is evident from the figure that the response of the system is equivalent up until the resonance frequency, where the response deviates with 800 Hz. This is sufficient as the fastest control loop has a cut-off frequency of 1.75 kHz, which is lower than the 5 kHz at which the response starts to deviate.

$$Z = \frac{1 + \frac{1}{T_s}s}{1 - \frac{1}{T_s}s} \quad (5.24)$$

$$H(s) = \frac{T_s(z + 1)}{2(z - 1)} \quad (5.25)$$

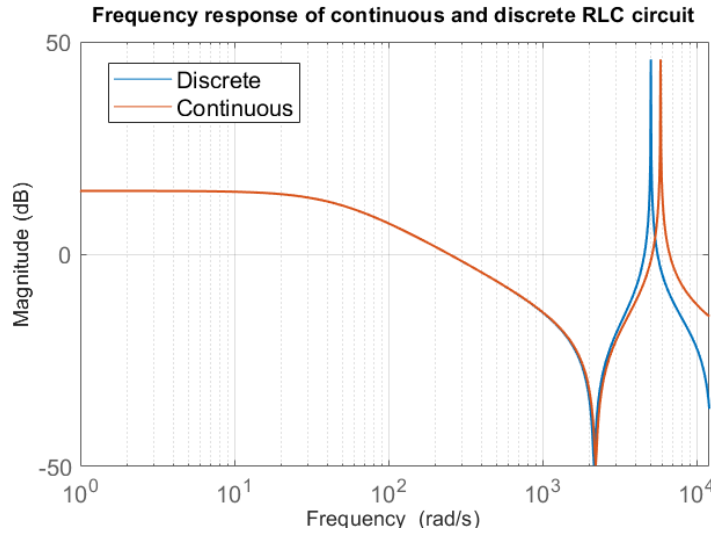


Figure 5.13: Comparison of the frequency response of the continuous and discretized system

5.4. Final Design parameters

The final design parameters discussed in this chapter are summarized in the table below. The design parameters are selected based on iterative tuning of the system during the simulation and testing phase.

Parameter	Value
k_u	2000 VAr/V
k_q	0.001 V/(VAr · s)
Q_{set}	0 VAr
V_{set}	400 V
V_{rated}	400 V
D	50 N · m · s/rad
J	10 kgm ²
ω_g	314.15 rad/s
ω_c Voltage loop	175 rad/s
ω_c Current loop	1750 rad/s
ω_c Power loop	500 rad/s
T_s	250 μ s

Table 5.1: The tuned parameters of the controller

6

Simulation and control validation

This chapter presents the simulation and validation of the developed control scheme. First the simulation models are introduced followed by the simulation results. The developed control scheme is evaluated in three different simulation setups. These include the initial model, which incorporates a detailed representation of the full IGBT-bridge, as well as the islanded and grid-connected configurations described in Chapter 2.1.1.

6.1. Modeling the microgrid in Simulink

The system described in Chapter 4 is developed in Simulink as shown in Figure 6.1. The voltage and current measurements are made using their corresponding sensor block, transformed to the dq reference frame and sent to the controller. The controller topology is explained in Chapter 5. The controller determines the output voltage of the converter, both its magnitude and phase angle. This information is sent to the SVPWM block which determines the required pulses for the IGBTs. A propagation delay is applied to all pulses before being sent to the IGBTs to prevent an algebraic error.

Modeling the system with a detailed circuit including each IGBT and its corresponding signal allows the full transient response of the system to be captured. This model is used when initially testing the controller to check whether the correct current and voltage waveforms are formed after the LCL filter. The results of this model are found in Chapter 6.3.

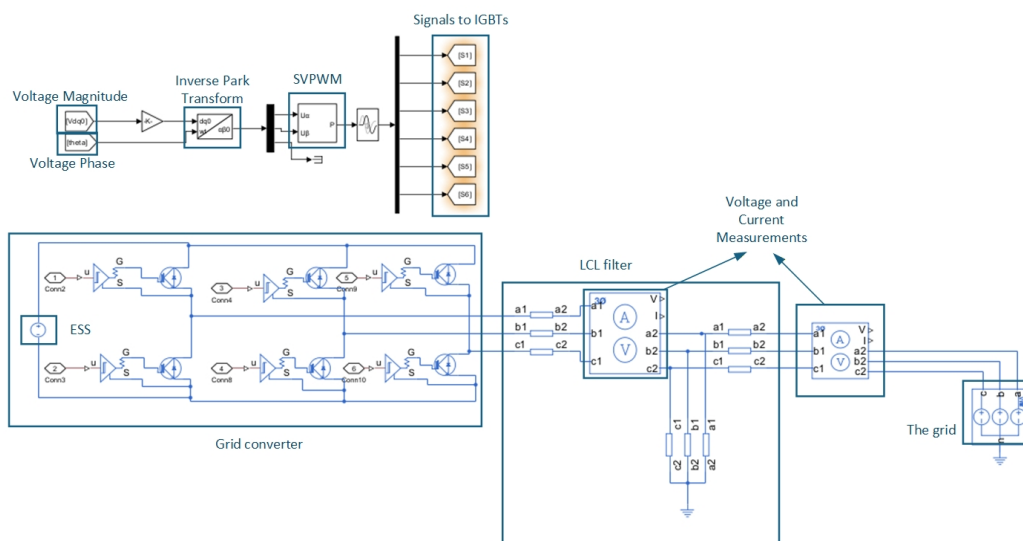


Figure 6.1: System as described in Chapter 4 modeled in simulink

Simulating the full switching behavior of the converter bridge is computationally intensive due to the high-frequency gate signals required for the SVPWM. Since this research focuses primarily on the fundamental dynamic response of the system rather than high-frequency switching losses, a simplified modeling approach is justified. Consequently, the converter bridge is approximated as an ideal controlled voltage source, as illustrated in Figure 6.2. The voltage setpoint determined by the controller is, after a propagation delay to avoid an algebraic error, transformed from the dq to the abc reference frame using the inverse Park transform. The transformed setpoint voltage is in turn used as input for the voltage controlled voltage source. Using this converter model the system described in Chapter 4 was simulated in the two scenarios described in Chapter 2.1.1. The simulation setup for each scenario can be found in Appendix C.

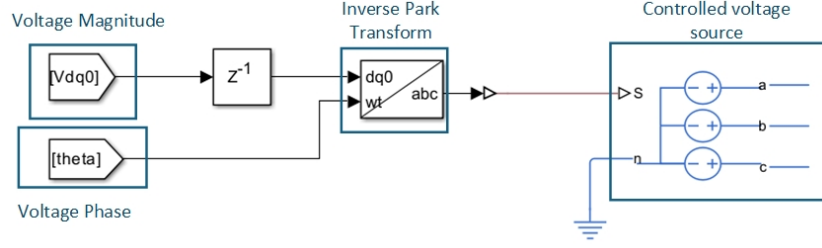


Figure 6.2: The voltage source converter modeled using a controlled voltage source

6.2. Modeling the synchronous generator

The SG used in the test setup consists of a diesel engine as prime mover connected to an SG which transforms the mechanical power into electrical power. In Simulink this process is modeled with a diesel engine model and the Simulink synchronous machine (SM) block. The SM block requires two main inputs, the field voltage V_{ref} and the simulated mechanical torque from the diesel engine T_m . The field voltage is set by the AVR using Q-U droop control as shown in Equation 6.1. Where Q_{nom} is the nominal power of the generator, Q_{out} and V_{out} are the output reactive power and voltage of the SG respectively, V_{set} is the field voltage setpoint, k_q the reactive power droop constant and k_p , k_i and k_d are the PID constants. The PID controller determines the required field voltage V_{ref} to set the reactive power and voltage error to zero. The droop constant k_q is set at 0.05, hence at full load the voltage of the system drops to 95% of its nominal value. At no load the voltage is at 100% of its nominal value.

The diesel engine sets the torque input for the SM block. It is governed by the governor which sets the power setpoint P_{ref} based on a reference frequency ω_{ref} as shown in Equation 6.2. In isochronous control the governor has a fixed frequency reference ω_{ref} . In droop control mode the frequency setpoint is set by Equation 6.3. Where ω_0 is the nominal frequency, k_d is the droop coefficient and P_{out} and $P_{nominal}$ are the output and nominal power of the SG.

$$V_{set} = \frac{k_d s^2 + k_p s + k_i}{s} ((Q_{nom} - k_q Q_{out}) - V_{out}) \quad (6.1)$$

$$P_{set} = \frac{k_d s^2 + k_p s + k_i}{s} (\omega_{ref} - \omega_{motor}) \quad (6.2)$$

$$\omega_{ref} = \omega_0 + \frac{k_d P_{out}}{P_{nominal}} \quad (6.3)$$

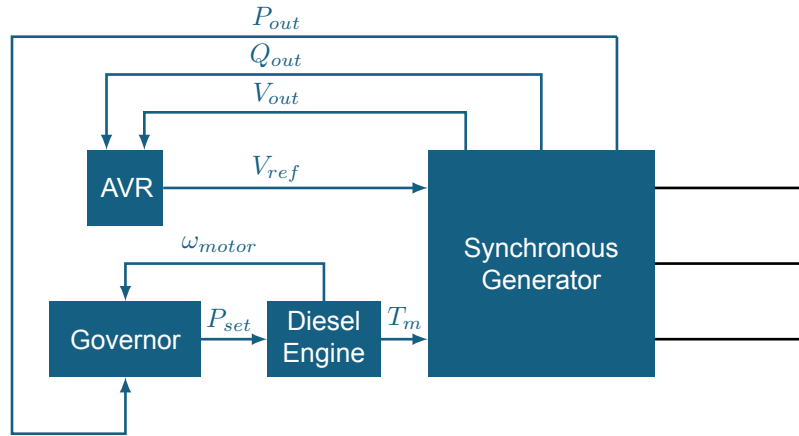


Figure 6.3: The simplified description of the diesel generator model in simulink

6.3. Simulation results

Three different situations are simulated. Firstly, the model as described in Chapter 4 is simulated with the setup described in Figure 6.1. This simulation will conclude whether the system response in Simulink corresponds to the calculated steady state response in Chapter 4.2. Then the model is simulated in islanded mode. The Simulink setup is shown in Figure C.2. Lastly, the model is simulated in grid-connected mode using the model of the SG described in Chapter 6.2. This full Simulink setup can be seen in Figure C.3. The voltages that are measured are the line-to-neutral voltages.

6.3.1. Initial model

To validate the system's performance, the Simulink model presented in Figure 6.1 is simulated. Initially, the system is modeled with a zero-power baseline condition. This is achieved by setting the reference power, P_{ref} , for the active power control loop to zero.

Firstly, as shown in Figure 6.4, the grid frequency successfully settles at its nominal reference value of 50 Hz. Concurrently, Figure 6.5 indicates that both the active and reactive power setpoints are accurately reached and maintained. A close-up view of the converter output voltage waveform is provided in Figure 6.6, demonstrating the expected PWM profile. The peak voltage aligns with the theoretical value of $400 V_{dc}$ dictated by Equation 6.4. The three phase voltages at PCC are depicted in Figure 6.7a, verifying the LCL filter's effectiveness.

Furthermore, the dq-axis components of the voltage across the capacitor is given in Figure 6.8. The results are the same as calculated from the state space matrices of the system provided in Figure 4.4c. Additionally, the dq-axis current at PCC is shown in Figure 6.9b and oscillates around zero, which is equivalent to the steady state current calculated in Figure 4.4b. However, it is evident in Figure 6.9a that the current is not sinusoidal, which is due to its low value. The capacitor of the LCL filter always draws a small current. Usually in perspective to the current towards the grid this current is a small proportion of the total delivered current. However, as the power reference is now set to zero, there is little current flowing towards the grid and this current now predominantly goes towards the capacitor. The capacitor current is shown in Figure 6.10. When setting the reference power to 42.5 kW, the nominal power of one SG, the grid current is sinusoidal as evident in Figure 6.11a. The current through the capacitor remains the same, but is now a smaller proportion of the total current.

At a power setpoint of 42.5 kW, the peak current injected into the grid is approximately 85 A, as demonstrated in Figure 6.11b. The current reaches this steady-state value in 0.6 seconds. This settling time is determined by the bandwidth of the tuned PI controller. While a higher controller bandwidth decreases the rise and settling times of the current, it also increases the controller's susceptibility to high-frequency noise [3].

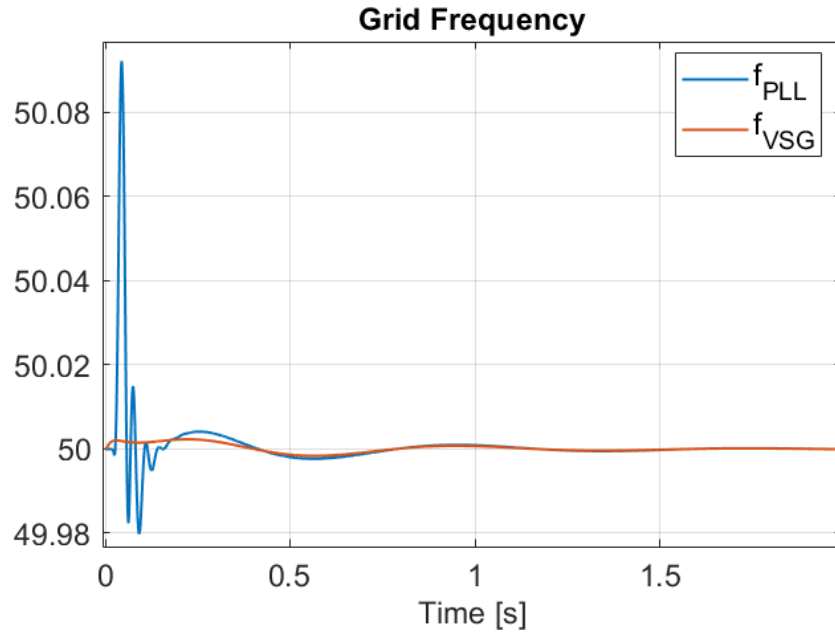


Figure 6.4: The grid frequency upon initial connection of the converter

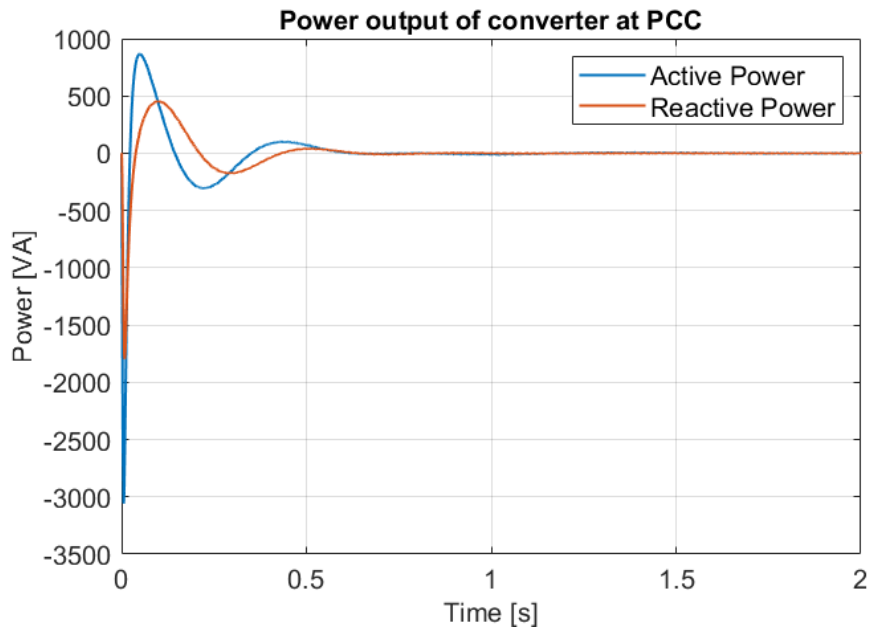


Figure 6.5: The output power of the converter as measured at the PCC

$$V_{LN} = \frac{2}{3} V_{dc} \quad (6.4)$$

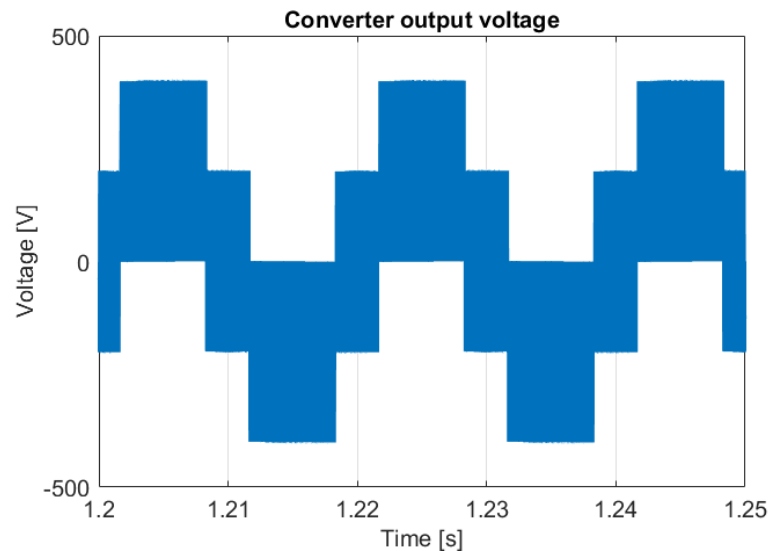
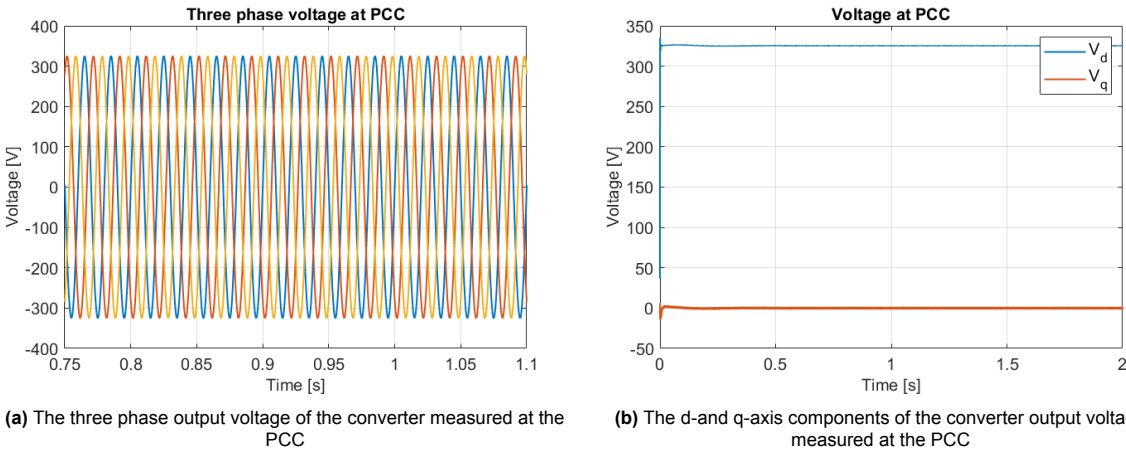


Figure 6.6: The voltage at the output of the converter



(a) The three phase output voltage of the converter measured at the PCC (b) The d- and q-axis components of the converter output voltage measured at the PCC

Figure 6.7: The voltage at the PPC both before and after the park transformation

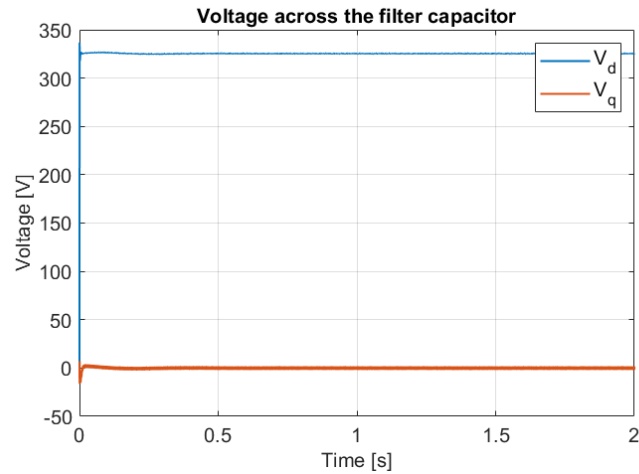


Figure 6.8: dq axis voltage across the filter capacitor

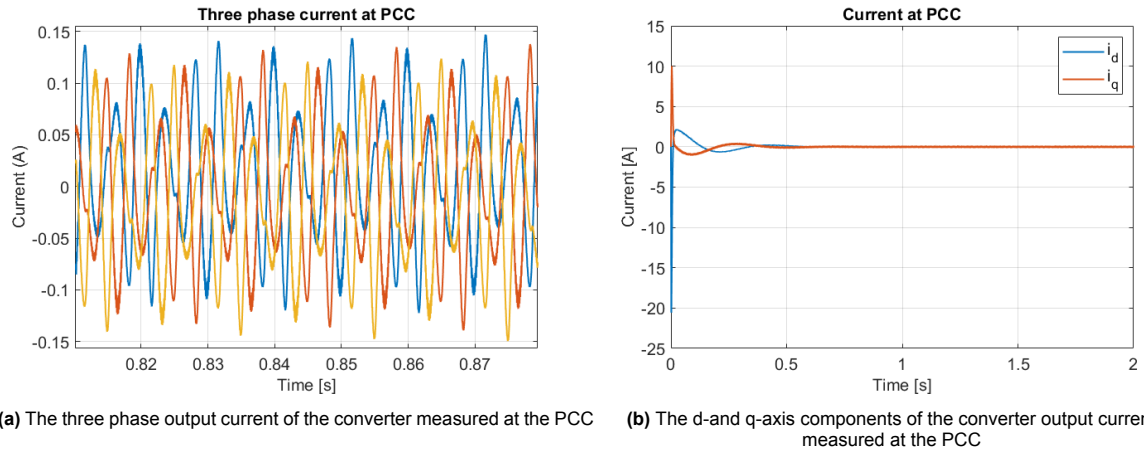


Figure 6.9: The current at the PPC both before and after the park transformation

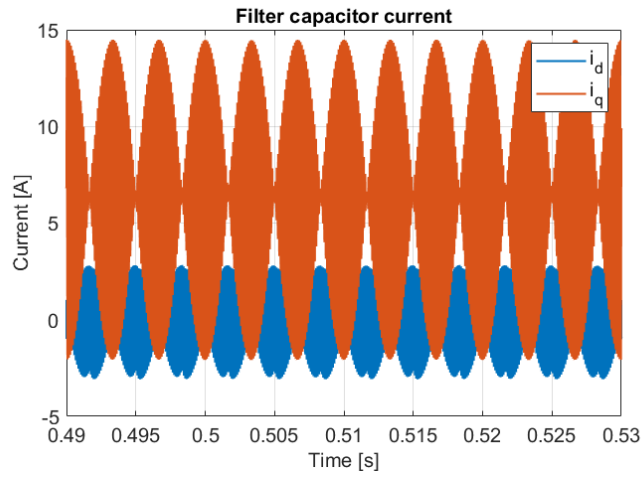


Figure 6.10: The current through the capacitor

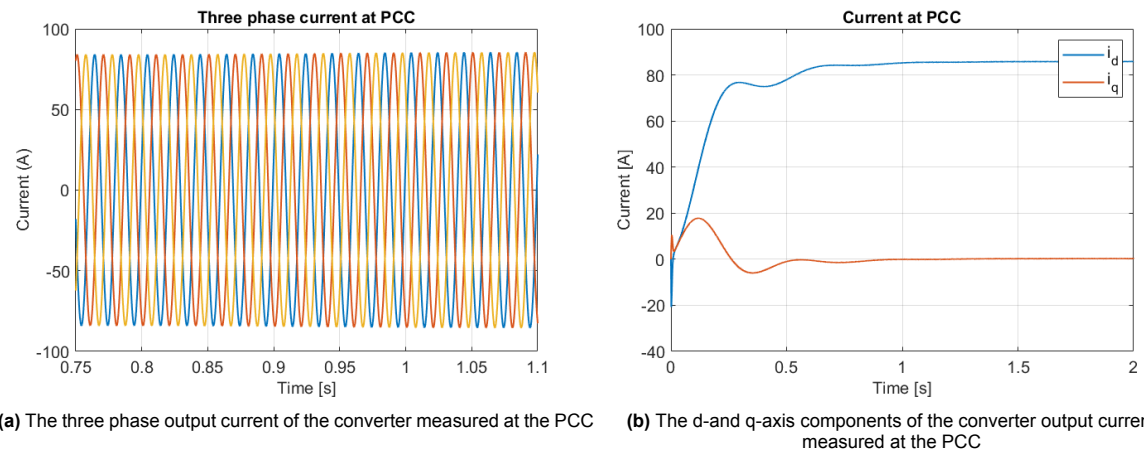


Figure 6.11: The current at the PCC both before and after the park transformation

6.3.2. Islanded mode

The island mode capabilities of the converter were evaluated using the simulation architecture shown in Figure C.2. At $t=7.5$ seconds a sudden load step is introduced, increasing the power demand from 65 kW to 85 kW. Figure 6.12a shows the power delivered by the converter to the load. Both before and after the load change the power supplied by the converter is equivalent to the power demanded by the load. The reference power set by the PI controller for the active power control loop can be seen in Figure 6.12b. From this figure it can be concluded that the power reference follows the power demanded by the load.

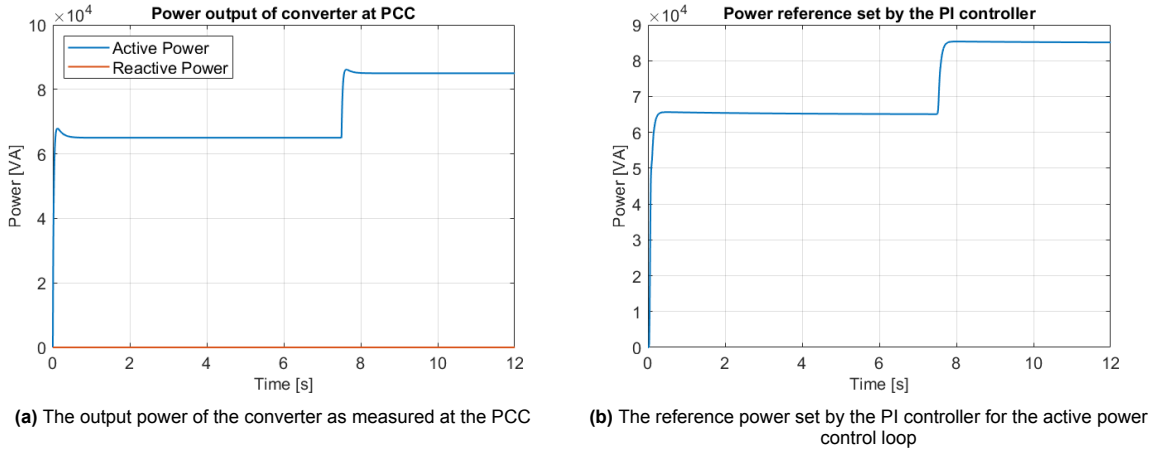


Figure 6.12: Power delivered by the ESS

Furthermore, the grid frequency remains constant at 50 Hz, both before and after the load change as evident from Figure 6.13a. Figure 6.13b shows the frequency dip during the load change. The frequency does not dip past 49.89 Hz, which is far within the requirements. However, the grid frequency does show an oscillatory response after the load change. This phenomena is caused by the inertia in the system. The inertia ensures the RoCoF is small, but causes a more oscillatory response. Tuning of the inertia coefficient is further discussed in Chapter 7.3.4. The oscillations are well-damped and decay rapidly within the 30 second requirement.

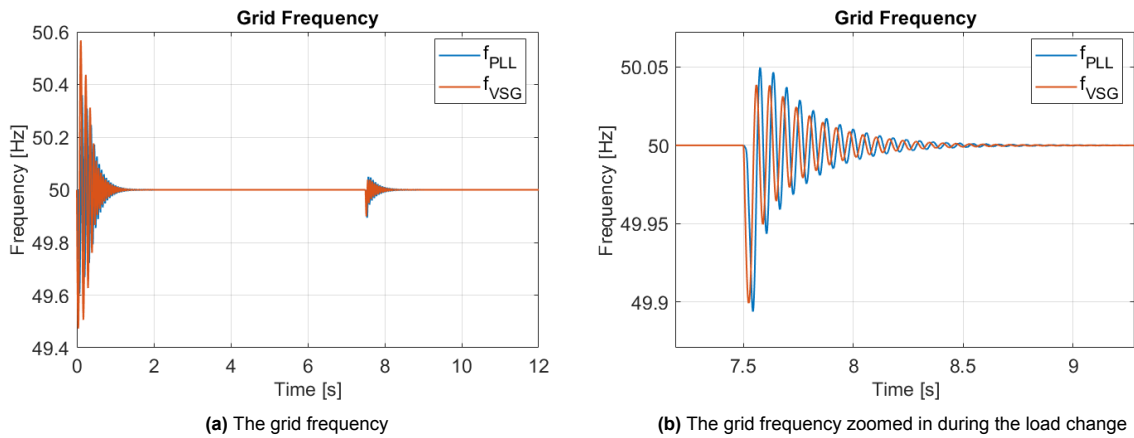


Figure 6.13: The grid frequency in islanded mode at initial connection and during a load change

Lastly, Figure 6.15 shows the voltage at PCC, which is kept constant at 230 V rms or 325 V peak due to the reactive power control loop. Figure 6.14 shows the reference voltage sent from the reactive power control loop to the inner control loop. It is evident from this output that the voltage reference peaks slightly but remains under the 4 volt deviation. To deliver the extra power required by the load, the current injected to the grid is adjusted from 133 A to 174 A peak to peak. This is shown in Figure 6.16.

The current increase is according to Equation 6.5 where P is the active power, V_L is the rms line to ground voltage and i_l is the rms phase current.

$$P = \sqrt{3} \cdot V_L \cdot i_L \quad (6.5)$$

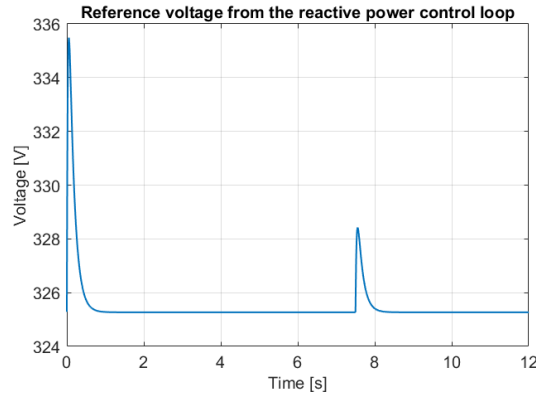
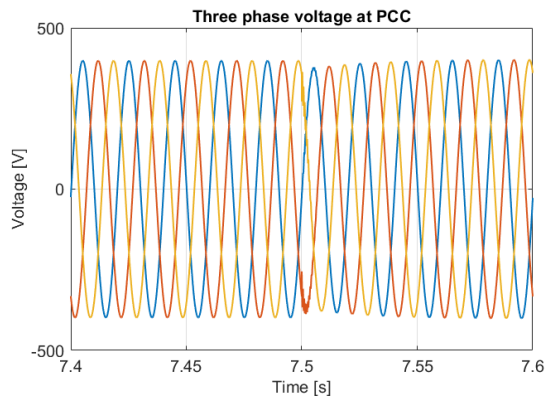
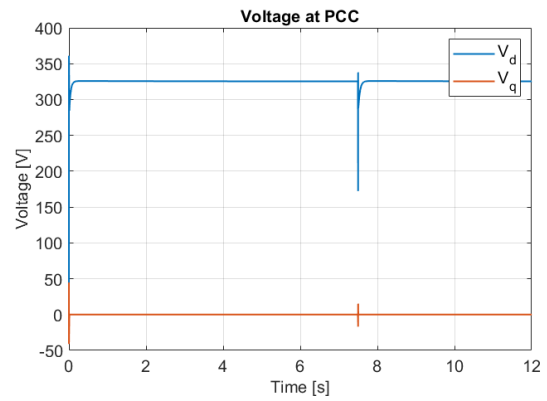


Figure 6.14: The reference voltage from the reactive power control loop

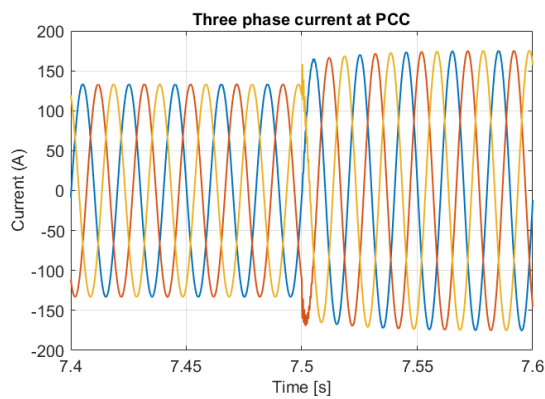


(a) The three phase output voltage of the converter measured at the PCC

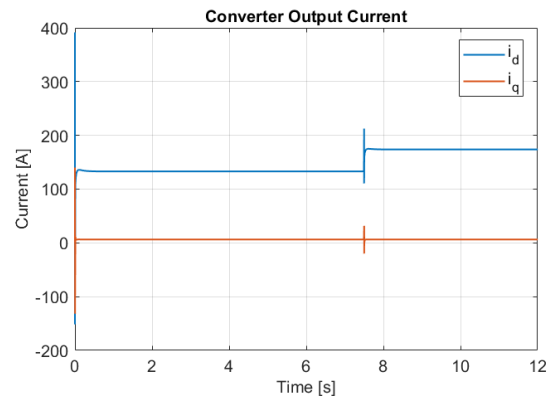


(b) The d- and q-axis components of the converter output voltage measured at the PCC

Figure 6.15: The voltage at the PPC both before and after the park transformation



(a) The three phase output current of the converter measured at the PCC



(b) The d- and q-axis components of the converter output current measured at the PCC

Figure 6.16: The current at the PPC both before and after the park transformation

6.3.3. Connected to Synchronous generator

The model as shown in Figure C.3 is simulated. The reference power of the converter is set to zero. At first only the SG is connected to the load. At $t=2.5$ seconds the converter is connected and at $t=10$ seconds the load increases from 22.5 kVA to 42.5 kVA, with a power factor of 0.916. A single-generator equivalent model is adopted to reduce simulation time. This simplification is valid under the assumption that both generators are identical and operate synchronously, each consistently contributing half of the total power demand.

The simulations are run with the SG in isochronous control mode. This means that there is no frequency droop, hence only one frequency setpoint. In frequency droop control the converter frequency setpoint and the frequency setpoint from the SG do not reach a consensus, hence the model runs into an error.

Figure 6.17b shows the frequency measured at the PCC with and without the virtual inertia implementation. It is evident that the frequency setpoint is at 50.05 Hz. This frequency, is set by the SG due to the droop line. The SG has a droop line where at no load the frequency is at 50.05 Hz, and at 95% load the frequency is at 50 Hz. As the SG now operates in isochronous control it holds the frequency reference at no load. Which is why it has its frequency setpoint at 50.05 Hz. With the virtual inertia implementation the frequency dip is improved from a 0.2 Hz dip to a 0.07 Hz dip. However, the time it takes for the frequency to settle back to its setpoint value is nearly 2 seconds longer. This trade-off depends on the tuning of the inertia coefficient and damping constant. Tuning these parameters can influence the frequency settling time, the frequency nadir and oscillations. These parameters are tuned in Chapter 7.3.4.

Figure 6.17b shows the frequency measured at PCC on the converter side of the breaker. This shows how the VSG control sets its own frequency at 50 Hz. When the converter is connected the frequency fluctuates as there are two different frequency setpoints. Eventually the SG and converter come to a consensus at a frequency of 50.05 Hz. To achieve this frequency setpoint the converter supplies -5 kW of active power. This additional power is compensated by the SG as evident in Figure 6.18b, the blue line.

It is evident from Figure 6.18a that during the load change at $t=10$ seconds, the converter supplies 12.5 kW of active power. As the ESS has a quicker response to the load change it mitigates the frequency dip, as evident in figure 6.17a. After the load transient, the power supplied by the ESS reduces again. However, instead of settling at 0 kW, it settles at -5 kW due to the high frequency setpoint.

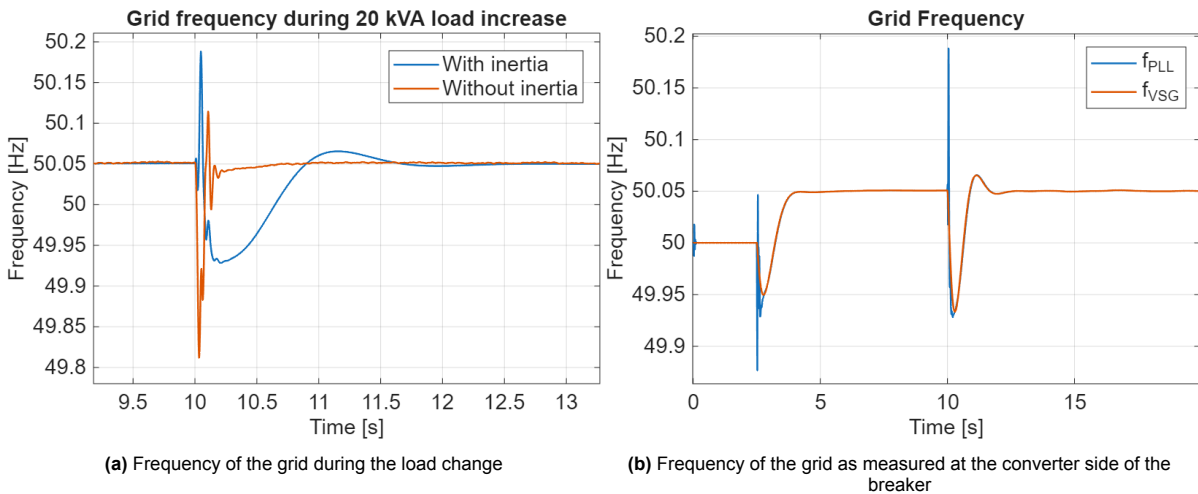


Figure 6.17: Grid frequency in grid-connected mode

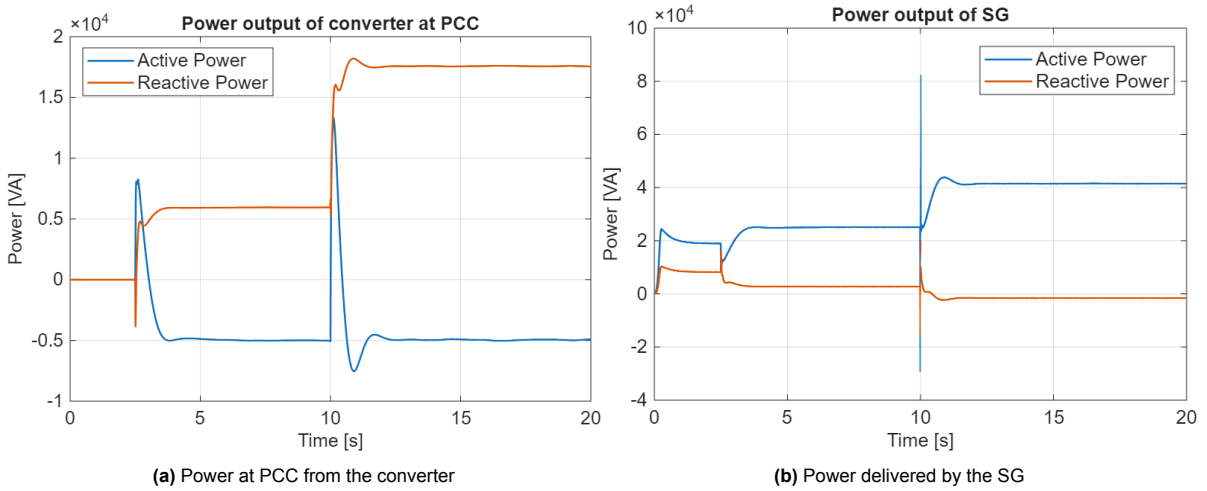


Figure 6.18: Power delivered by the converter and SG during a load change

The grid voltage during the load change both with and without VSG control is compared in Figure 6.19. Both the VSG control and the SG operate with their own Q-U droop characteristics. Without the VSG control the SG droop alone determines the voltage setpoint. This results in a voltage of 318 V at a load of 22.5 kVA and 310 V at a load of 42.5 kVA at the SG terminals. However, due to the voltage drop across the line impedance the voltage measured at PCC is reduced to 298 V and 275 V respectively, as illustrated in Figure 6.19.

When the VSG control is enabled the combined droop characteristics of both the SG and VSG establish new voltage setpoints of 322 V at 22.5 kVA and 316 V at 42.5 kVA. To maintain these higher voltage setpoint the VSG control requires the ESS to supply reactive power. Before the load change, the ESS delivers approximately 0.7 kVAr of reactive power as observed between 2.5 and 10 seconds in Figure 6.18a. The SG contributes an extra 0.2 kVAr. The resulting 0.8 kVAr required to meet load demands is dissipated across the line impedance. As the power produced by the SG is measured after the line impedance this is not visible in the plotted results.

When the load increases the ESS produces excess reactive power to maintain the voltage setpoint at 316 V. The SG compensates by providing capacitive power. This is an undesirable response as producing an excess reactive power contributes to system losses. The trade-off between the amount of reactive power provided by the ESS and the amount the voltage deviates from its set value depends on the droop constants k_u and k_q of the reactive power control loop. Tuning these constants and their influence on system voltage and reactive power contribution is discussed in Chapter 7.3.3. Figure 6.20 illustrates the voltage reference set by the reactive power control loop. By comparing it with the output voltage in Figure 6.19 it is evident that the system follows its voltage reference. All simulation results are summarized in Appendix F.

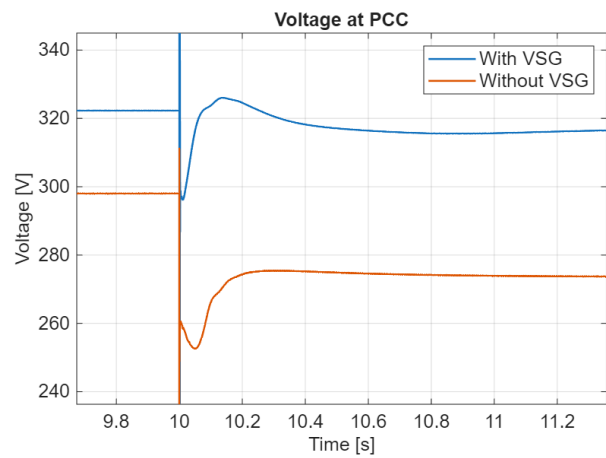


Figure 6.19: The simulated grid voltage during a 20kVA load increase. The response with and without VSG control is compared

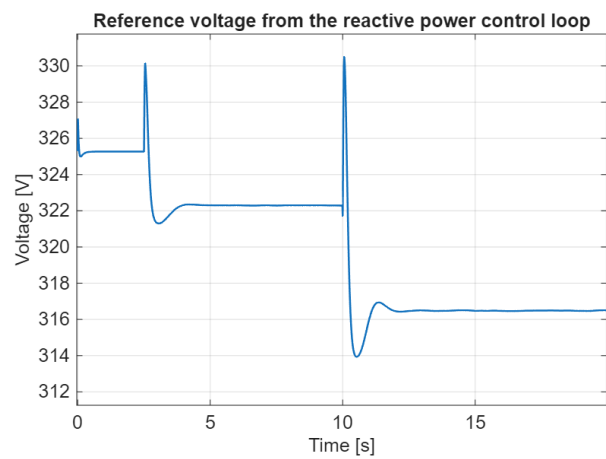


Figure 6.20: Reference voltage set by the reactive power control loop

7

Deployment and field testing

This chapter describes the test setup and identifies the load profiles used for testing. It further explains the adaptations to the controller developed in Chapter 5. Finally, the test results are analyzed and controller parameters are tuned accordingly.

7.1. Setup

The test setup is shown in Figure 7.1. The load and ESS are modeled using an inverter connecting the common DC bus to the grid. The SGs, ESS and load can all be disconnected and connected from the grid using a switch. At first, only one SG and a load of 5 kVA are connected to the grid. The SG now initializes and sets the grid. Before the second SG connects its phase sequence, phase, frequency and voltage must be synchronized with that of the grid. After synchronization the second generator is connected. Before connecting the ESS, the reset signals, parameter 106.50 bits 2,3 and 4 must be set to high. By doing so the integrators are reset to zero causing the reference voltage and frequency to be set at 400 V and 50 Hz respectively. Now the ESS is safe to connect. Once connected, the reset signals are set to low, and the converter can synchronize with the grid. When the converter is in islanded mode the SGs are disconnected. The measurements for the controller of the converter are taken at the PCC by an auxiliary measurement unit from ABB named the BAMU. The voltage measured by the BAMU is the rms line-to-line voltage.

7.1.1. Load profiles

On a shipboard microgrid different types of loads are connected. At connection the rate at which the loads consume power varies depending on the type of loads. A DOL motor for example would consume a large amount of power quickly, mainly due to the inrush current. A thruster motor connected via a drive can demand power at a controlled rate. Pumps and compressors on the other hand have a starting up time depending on the mechanical load. To replicate these varying loading conditions different load ramps are used during testing. These load ramps are represented in Figure 7.2. The load increases with 20 kVA with a power factor of 0.916.

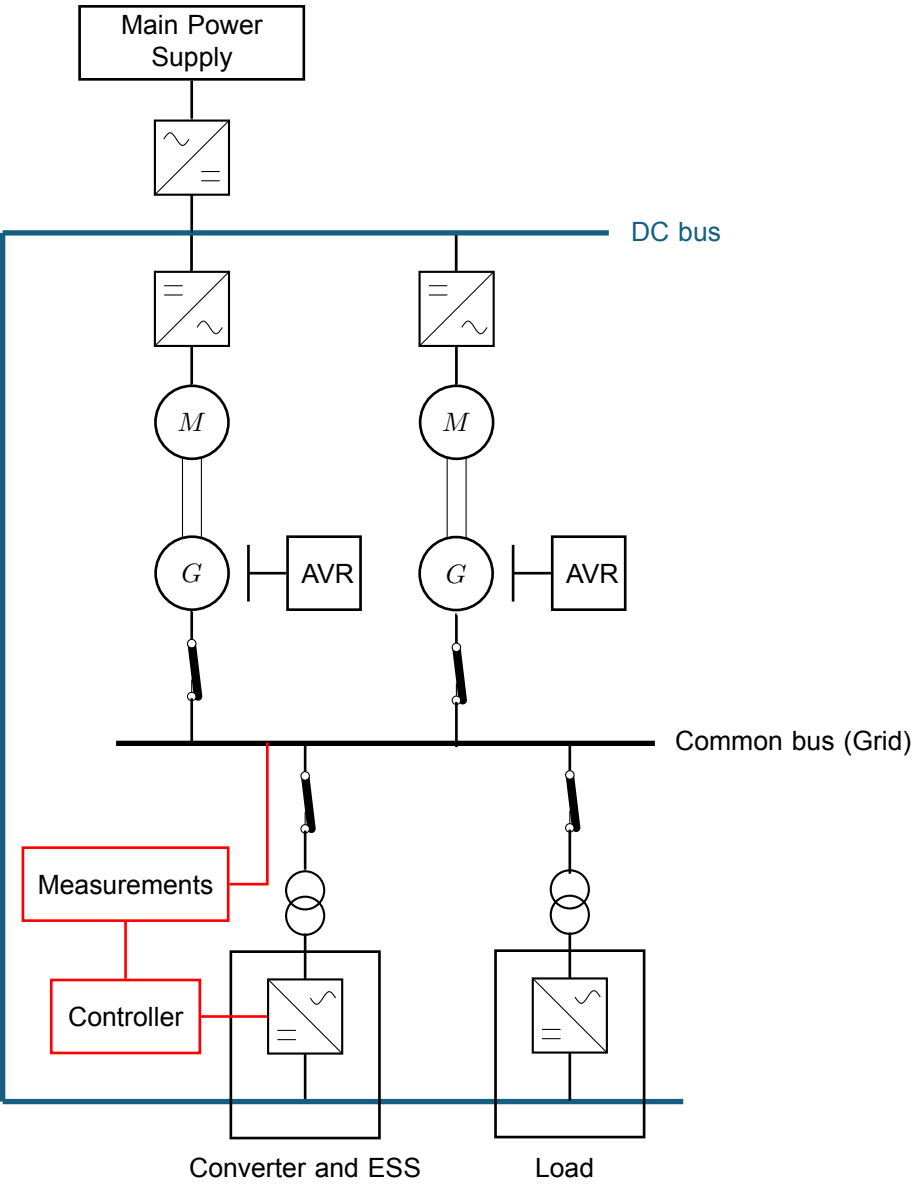


Figure 7.1: Test setup

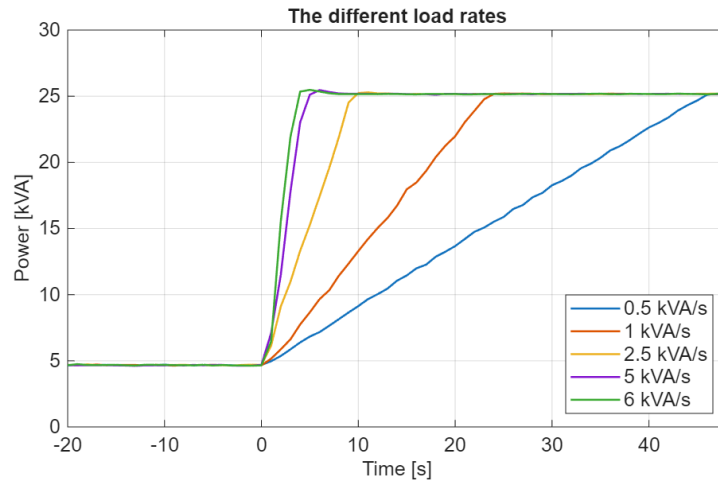


Figure 7.2: The different load rates

7.2. Controller Adaptations

Figure 7.3 illustrates the adaptation and implementation of the controller explained in Chapter 5 within the Crealizer™ environment. The converter used in the test setup is the ABB drive, ISU ACS880, set in power control mode, with the optimal grid control (OGC) functionality. In this operating mode the converter operates based on a set frequency and voltage input. Thus, only the outer VSG control loops are implemented as these determine the reference voltage and frequency to the converter.

The corresponding system parameters are summarized in Tables 7.1 and 7.2. Upon initial connection of the drive, reset signals are required to mitigate the large error present before synchronization. Since integrators (including those in the PI controller) would otherwise retain this accumulated error during future calculations, they must be reset to zero. The system remains in the reset state if the reset signal is high. Additionally, the reference power is determined by Bit 1 of the parameter 106.50, which can be turned on and off based on the scenario of the system.

Parameter	Name	Value/unit
Set parameters		
147.80	f_{ref}	50 Hz
147.81	Override frequency	50 Hz
147.82	P_{ref}	0 W
147.83	D	50 N · m · s/rad
147.84	$\frac{1}{J}$	0.1 kg ⁻¹ m ⁻²
147.85	ω_g	315 rad/s
147.86	k_u	2000 VAr/V
147.87	k_q	0.005 V/VAr
Inputs		
101.09	Measured grid voltage	V
101.14	Measured reactive power	kVAr
101.35	Measured power	kW
190.15	Measured frequency	Hz
Outputs		
127.01	Voltage	V
128.01	Frequency	Hz

Table 7.1: The definitions of the different parameters used in the final controller

Parameter	Bit	Functionality
106.50	1	Selects which power reference
	2	Resets the integrator of the active power loop
	3	Resets the PI controller
	4	Resets integrator of reactive power control loop
110.01	1	Digital input, overwrites reference frequency

Table 7.2: The reset and selector signals

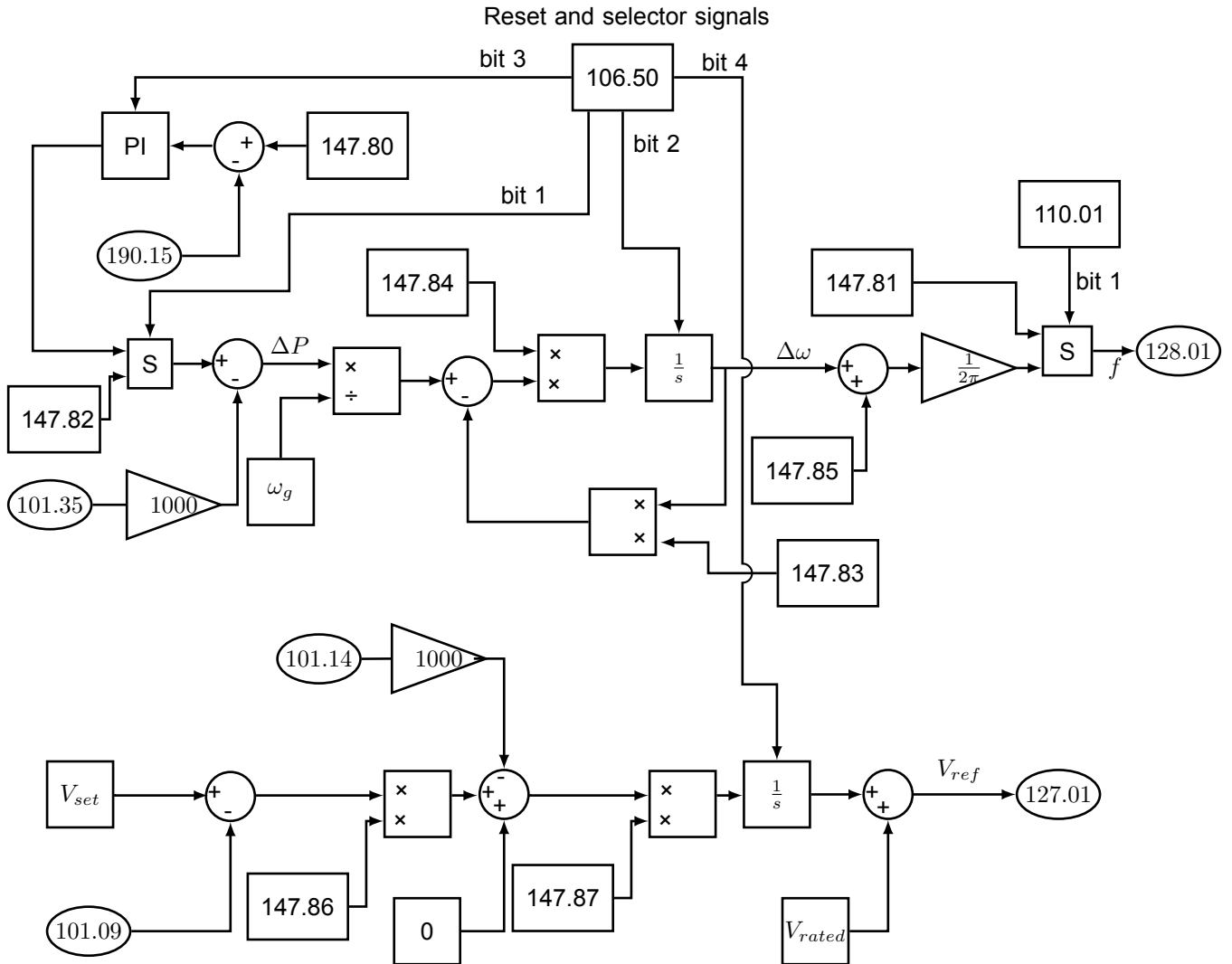


Figure 7.3: The controller schematic implemented in Crealizer

7.3. Testing results

The response of the system during the different load changes indicated in Figure 7.2 will be analyzed in terms of voltage, frequency, active and reactive power deviations. When in islanded mode the ESS and converter form the grid. Thus, the converter must set its own grid frequency and voltage. During a load change the voltage and frequency deviations must be minimal. When in grid connected mode the converter must only provide power during loading transients to help mitigate large frequency and voltage fluctuations.

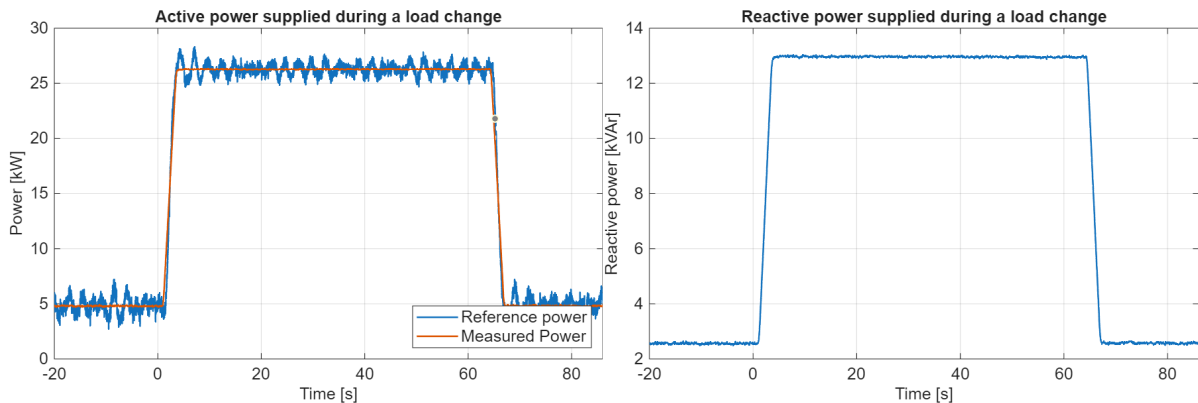
7.3.1. Islanded mode

The converter is tested in islanded mode as described in Chapter 2.1.1. The power provided by the ESS through the converter is shown in Figure 7.4, where 7.4a and 7.4b present the active and reactive power respectively. The load connected to the grid is initially 5.6 kVA with a power factor of 0.89. The reference power for the active power control loop is set by the PI controller based on the frequency deviation from its setpoint, 50 Hz. At $t=0$ seconds the load increases from 5.6 kVA to 29 kVA with a slope of 6 kVA/s after which it decreases back to 5.6 kVA at approximately $t=65$ seconds.

Figure 7.4 shows the power delivered by the converter to the load, Figure 7.4a illustrating the active power and Figure 7.4b the reactive power. In Figure 7.4a, the orange curve shows the power delivered to the load filtered by a low-pass filter with time constant $\tau = 10$ ms. During the load increase, the active power delivered by the converter follows the load demand. The reference power, indicated by the blue curve, tracks the load variation accordingly. However, notable fluctuations of the reference power around the reference value are observed. These oscillations are due to the tuning of the PI controller gains.

In Figure 7.5 the frequency as measured by the PLL in the BAMU is shown. The frequency deviation is approximately 0.02% from its steady state value. This deviation is amplified by the proportional gain in the PI controller, which is reflected in the fluctuations of the power reference. Although reducing the proportional gain could reduce these oscillations, it would also weaken the system's response to frequency deviations and potentially lead to a larger frequency dip. Since the power output remains stable, further tuning of the PI controller is not considered necessary.

Furthermore, Figure 7.5 demonstrates that the grid frequency deviates minimally from its set value during the load change. The frequency namely dips to 49.95 Hz (0.1%), during a load increase and it peaks at 50.04 Hz (0.08%), during a load decrease. The RoCoF is 0.057 Hz/s. The frequency settling time is 2.79 seconds. This is far within the requirements.



(a) The power delivered by the converter during a 24 kVA load increase followed by a 24 kVA load decrease. The delivered power is compared to the reference power set by the PI controller

(b) Reactive power delivered by the converter during a 24 kVA load increase followed by a 24 kVA load decrease

Figure 7.4: The active and reactive power supplied to the load

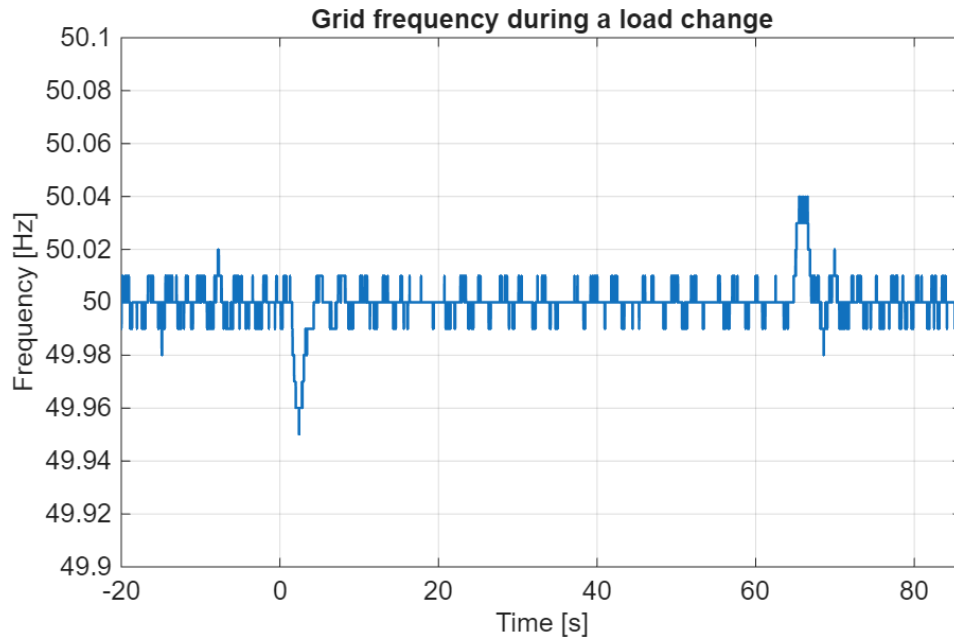


Figure 7.5: The transient frequency of the grid during a 24 kVA load change at a rate of 6 kVA/s

Figure 7.6 shows the grid voltage during the load transition. The blue curve represents the grid voltage for a voltage droop constant $k_u = 20000$, while the orange curve corresponds to $k_u = 2000$. In grid-connected mode, the droop constant is set to $k_u = 2000$. However, with this tuning, the voltage in islanded mode deviates beyond the specified limits, which is undesirable. Therefore, the droop constant is increased in islanded mode to ensure the requirements are satisfied.

The reference line-to-line grid voltage is 400 V. As shown in Figure 7.6, the steady-state voltage remains close to this value at approximately 399.9 V. During the load change, the voltage settles at 399.16 V, corresponding to a deviation of 0.189%, which is well within the specified limits. The settling time for both load increase and decrease is approximately 4.7 s, also satisfying the requirements. A summary of the system performance relative to the requirements is provided in Table 7.3.

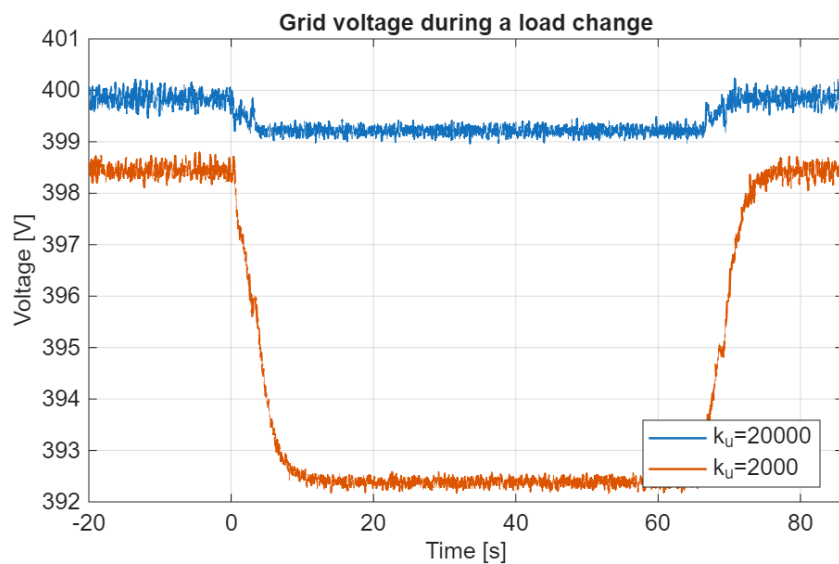


Figure 7.6: The transient voltage response during a 24 kVA load change. Load profile given by Figure 7.4a

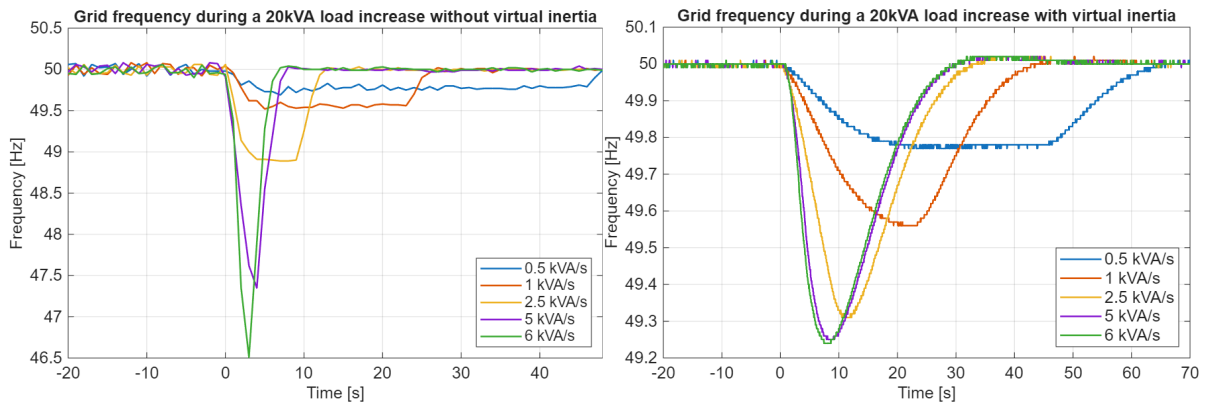
Requirement	Actual value	Limit
Maximim RoCoF	0.057 Hz/s	0.5 Hz/s
Frequency Nadir	0.05 Hz = 0.1%	2%
Frequency Peak	0.04 Hz = 0.08%	2%
Frequency Settling Time	2.79 seconds	30 seconds
Voltage Deviation	0.189%	1%
Voltage Settling Time	4 seconds	10 seconds

Table 7.3: Testing results for the grid forming response of the converter controller compared to the requirement values.

7.3.2. Grid-connected mode

The converter is tested in grid-connected mode, as described in Chapter 2.1.1. In this operating mode, the converter supplies power only during load transients to mitigate frequency nadir and reduce RoCoF. The response of the system is evaluated both with and without the ESS connected, hence, with and without the virtual inertia implementation. The load is increased with 20 kVA at a power factor of 0.916. The response of the system was tested at various power ramps, which are indicated in Figure 7.2.

The resulting frequency deviations for the different load changes are shown in Figure 7.7. Figures 7.7a and 7.7b present the frequency response without and with virtual inertia, respectively. Figure 7.7a shows that, in the absence of virtual inertia, the frequency deviation remains within the specified limits for load ramps of 0.5 kVA/s and 1 kVA/s. However, for ramps steeper than 1 kVA/s, the frequency deviation exceeds the allowable limits. In contrast, Figure 7.7b demonstrates that, with the implementation of virtual inertia, the frequency response remains within the required limits for all tested load ramp rates, including the steepest ramp of 6 kVA/s. Based on these results, the responses corresponding to the 1 kVA/s and 6 kVA/s load ramps are selected for further comparison between the cases with and without virtual inertia.



(a) The frequency of the grid without virtual inertia at different load rates (b) The frequency of the grid with virtual inertia at different load rates

Figure 7.7: The frequency of the grid during a load increase at different rates, without and with virtual inertia

Figure 7.8a compares the grid frequency during a load change with and without virtual inertia. The load is increased with 20 kVA at a rate of 6 kVA/s. The figure demonstrates that with virtual inertia the RoCoF and consequently the frequency nadir is reduced significantly. Specifically, the RoCoF is reduced from 1.14 Hz/s to 0.17 Hz/s and the nadir is reduced from 46.5 Hz to 49.25 Hz. However, this improvement comes at the expense of a longer settling time. With virtual inertia, the frequency settles in 25 seconds, compared to only 7 seconds without it. This longer settling time is due to the limited RoCoF, causing the frequency to return to its equilibrium value at a slower rate. Figure 7.8b shows the frequency of the grid after a load change at a rate of 1 kVA/s both with and without virtual inertia. As the load increases more gradually, the system exhibits a better response to the load change, even in the absence of additional inertia. Consequently, under conditions with slower load variations, the supplementary inertia does not significantly improve performance.

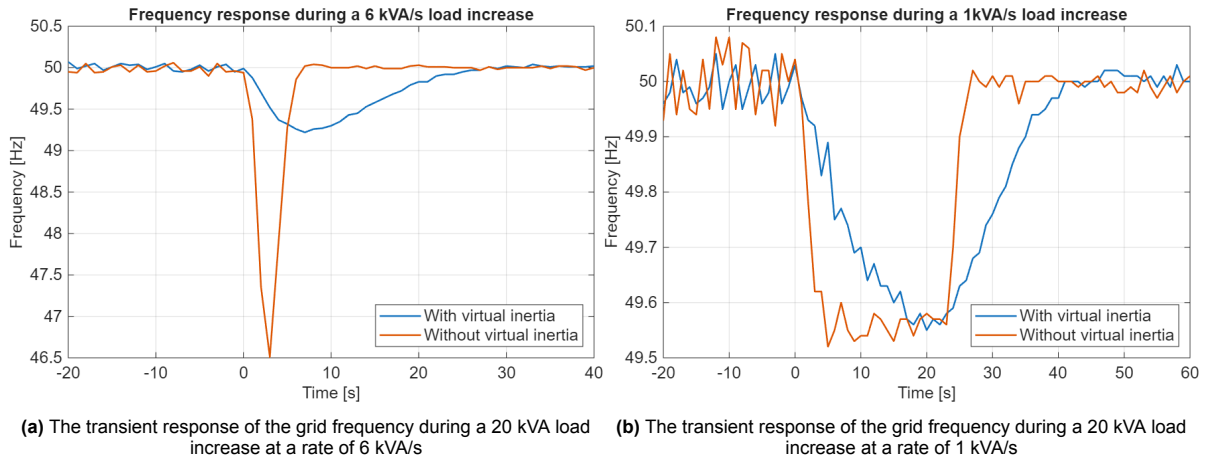


Figure 7.8: A comparison of the transient response of the grid frequency during a 20kVA load increase at a rate of 6 kVA/s and 1 kVA/s

Figure 7.9 illustrates the grid voltage during a 20 kVA load increase at a rate of 6 kVA/s and 1 kVA/s in Figure 7.9a and Figure 7.9b respectively. Without the VSG control implementation, the voltage deviation exceeds 1% during a steep load increase. However, for load gradients of 1 kVA/s or slower, the voltage remains within the requirements. The introduction of VSG control significantly improves system performance under rapid load changes. More specifically, during a load increase of 6 kVA/s, the voltage dip of 10 V is reduced to 4 V with the virtual inertia implementation. Furthermore, the voltage level remains within the required limitations, reaching its lowest voltage level at 396 V which is a voltage deviation of exactly 1%.

Reactive power sharing by the ESS and SG is governed by the droop control implemented in the AVR of the SG and the reactive power control loop of the VSG. This coordinated control ensures both components can operate at a common voltage setpoint. This determined voltage setpoint is 399 V at 5 kVA and 396 V at 25 kVA. In contrast, when only the SG is operating its droop determines a setpoint of 400 V at 5 kVA and 396 V at 25 kVA.

Prior to the loadstep, without the VSG control, the combined reactive power from both SGs is approximately 2 kVAr, as shown in Figure 7.10b. Following a load increase of 20 kVA the total reactive power is approximately 10 kVAr. This is consistent with the calculations derived from Equation 7.2, where S is the apparent power of 5 kVA or 25 kVA, P is the active power, Q is the reactive power and PF is the power factor of 0.916.

The reactive power response of the ESS under VSG control during a 20 kVA load increase is illustrated in Figure 7.10a. At a low load of 5 kVA, the ESS supplies the full reactive power demand of 2 kVAr. During the transient of the load increase the ESS provides the majority of the required reactive power to reduce the voltage deviation from 10 V to 4 V. In steady state operation the ESS supplies 6.2 kVAr, while the SGs contribute 4 kVAr. The distribution of reactive power is the results of the droop characteristics implemented in both components.

$$\theta = \cos^{-1}(PF) \quad (7.1)$$

$$P = S \cos(\theta) \quad (7.2)$$

$$Q = S \sin(\theta) \quad (7.3)$$

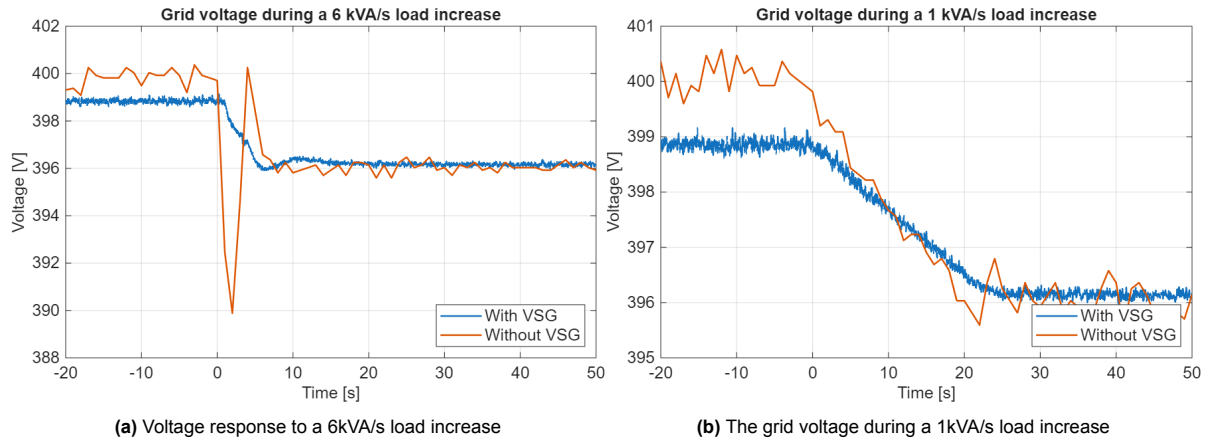


Figure 7.9: The grid voltage during a 20kVA load increase

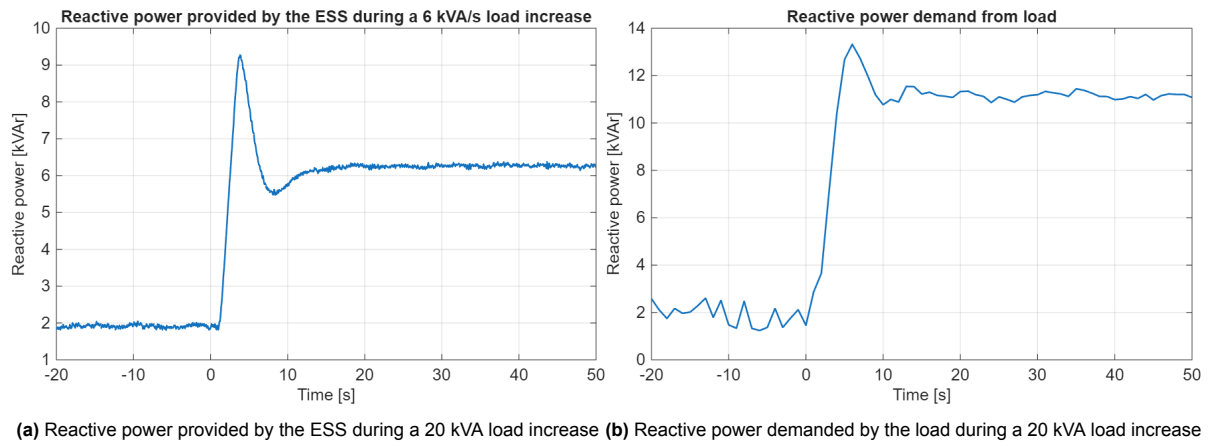


Figure 7.10: Reactive power delivered to the load by the ESS and the reactive power demanded by the load

Figure 7.11 presents the active power supplied by the ESS during a 20 kVA load increase at a rate of 6 kVA/s in Figure 7.11a and 1 kVA/s in Figure 7.11b. As illustrated in Figure 7.11a, the ESS initially provides the majority of the additional power during rapid load increase. This behavior is due to the faster dynamic response of the ESS compared to the SG. As a result the ESS compensates for a sudden increase in demand, thereby reducing the magnitude of the frequency dip. In contrast, Figure 7.11b illustrates that at a lower loading rate the ESS does not exclusively supply the additional power. Instead the SG contributes more significantly as it has sufficient time to respond to the change in load. Consequently, the additional power demand is shared more evenly between the ESS and the SG under slower loading conditions.

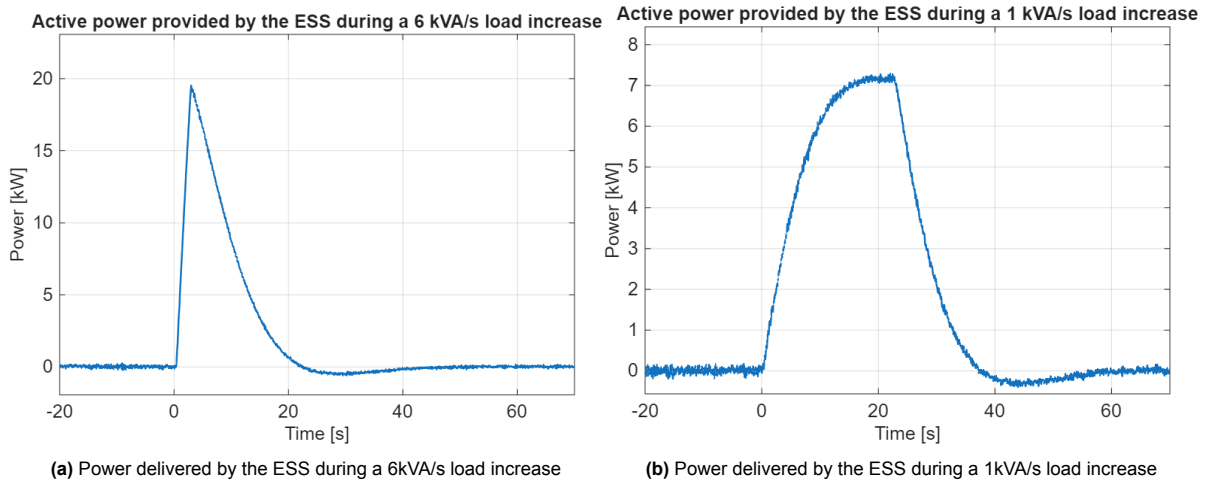


Figure 7.11: Power delivered by the ESS during transient load increase

Lastly, Figure 7.12 shows the grid frequency and power supplied by the ESS during a load decrease. By comparing Figure 7.12a and 7.7b it can be concluded that the frequency deviation and frequency settling time for both a load increase and decrease is the same. Only for a load decrease the frequency increases. Figure 7.12b indicates that, during a load decrease, the ESS absorbs the surplus power in the system resulting from the temporary mismatch between demand and supply. Further test results can be found in Appendix G.

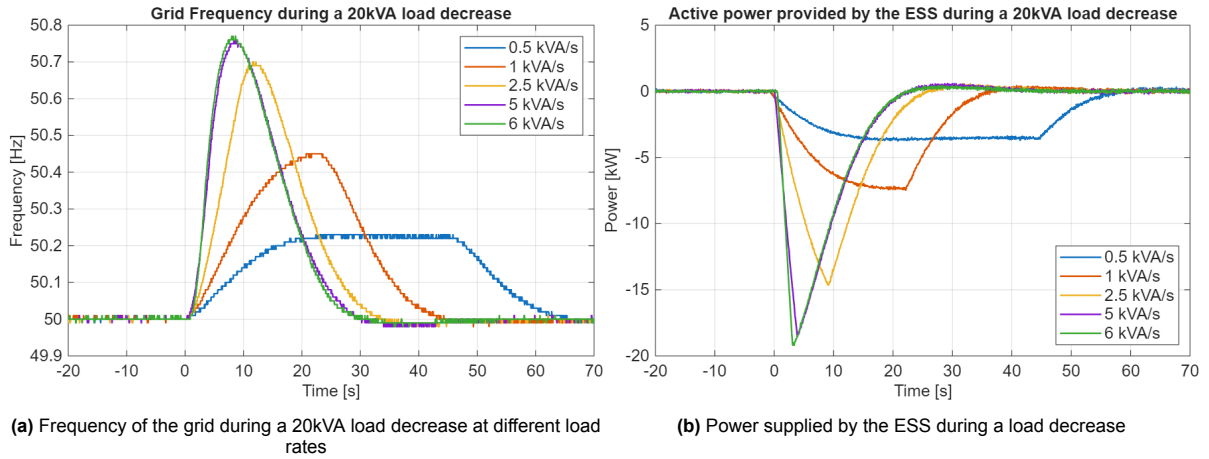


Figure 7.12: Frequency of the grid and power supplied by the ESS during a load decrease

7.3.3. Tuning the droop constants

Tuning the voltage and reactive power droop constants, k_u , in VAr/V and, k_q , in V/(VAr · s) respectively, is beneficial for controlling the voltage response of the system. These parameters were tuned such that the voltage requirements were met. The voltage requirements are as follows:

- Voltage dip < 4 V
- Voltage settling time < 10 seconds

As mentioned earlier the droop control allows the SG and the ESS to share the reactive power load at a common voltage level. The voltage setpoint and the reactive power supplied by the ESS can be determined by tuning the k_u and k_q droop constants. k_u determines how much the voltage deviates from its set value and k_q determines the rate at which the voltage changes.

Figure 7.13a presents the grid voltage during a 20 kVA load increase for different values of k_u . With a higher droop constant, the voltage deviation from its setpoint value, 400 V, becomes smaller. However,

minimizing the voltage deviation by setting k_U to a high value causes the reactive power supplied by the ESS to increase, as can be seen in Figure 7.13b. If a stricter voltage control is required, the droop must be more lenient on the reactive power error. This is the trade-off for tuning this parameter. In this thesis, the design approach was selected to ensure operation remained within the established system requirements, therefore increasing the droop constant to maintain the voltage deviation below the 1%. The droop constant k_U was hence chosen to be 2000. Scaling the droop constant larger than this would lead to the ESS supplying more reactive power which is undesirable.

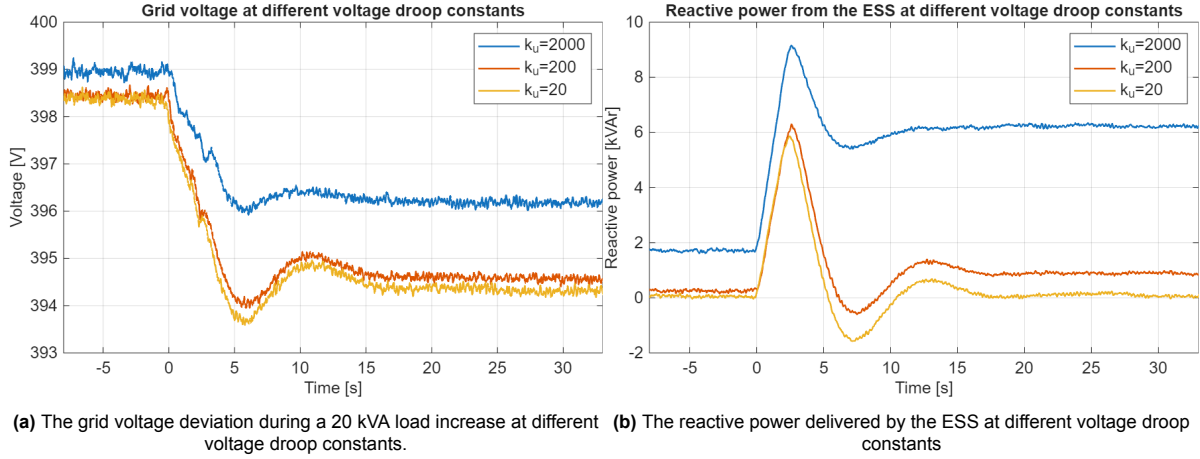


Figure 7.13: The effect of different voltage droop constants on the grid voltage and the reactive power supplied by the ESS

Figure 7.14a, illustrates the grid voltage following a 20 kVA load increase for different values of k_q . It can be observed that higher values of k_q result in a lower rate of change of voltage. A lower rate of change of voltage is beneficial as it prevents overshooting and large voltage fluctuations. The droop constant at 0.5 for example leads to a large fluctuating voltage output as evident in Figure 7.14b. However, a slower rate of change of voltage also means a slower voltage settling time. To achieve constrained rate of voltage variation while satisfying the settling time of 10 seconds, the droop constant k_q was set to 0.005.

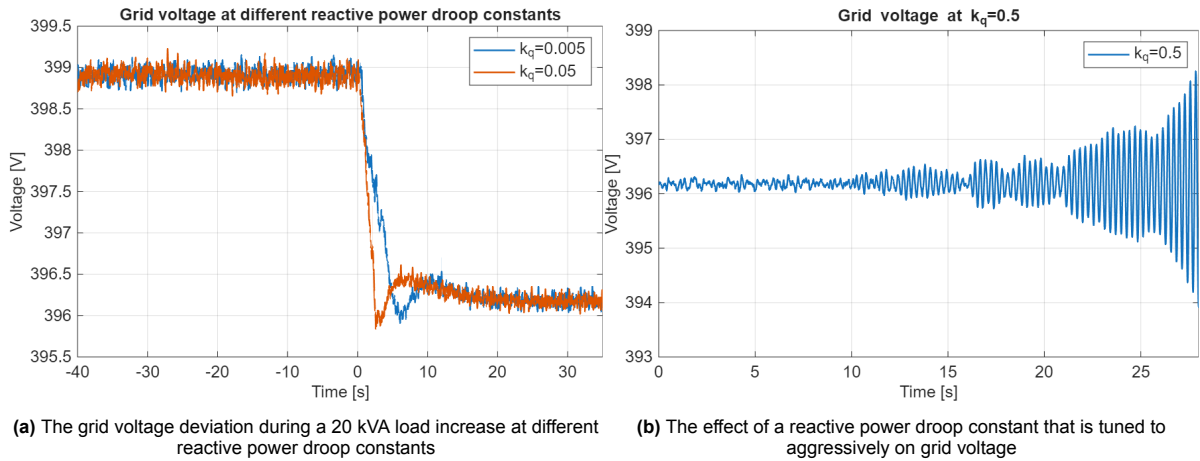


Figure 7.14: The effect of different reactive power droop constant on the change of grid voltage during a load increase of 20 kVA/s

7.3.4. Tuning the inertia coefficient and damping constant

When tuning the active power control loop, two key parameters must be configured: the inertia coefficient, J , in $\text{kg} \cdot \text{m}^2$ and the damping constant, D , in $\text{N} \cdot \text{m} \cdot \text{s}/\text{rad}$. These parameters should be tuned such that the response falls within the requirements. More specifically the frequency requirements during a 20 kVA load change. These requirements are as follows:

- RoCoF < 0.5 Hz/s
- Frequency deviation < 1 Hz
- Settling time < 30 seconds

The inertia coefficient and damping constant were adjusted, and the frequency settling time, nadir and RoCoF were recorded. The complete set of results is provided in Appendix E. A summary of these results is presented in Figure 7.15, which identifies the number of requirements that are met with different combinations of inertia and damping parameters.

It is observed that three combinations meet all requirements, these are summarized in Table 7.4. From the table it is evident that a configuration with an inertia coefficient of 1 and a damping constant of 50 results in the longest frequency settling time and largest frequency deviation. For an inertia coefficient of 10, it becomes apparent that there is a trade-off between damping constants. A higher damping constant leads to a longer settling time, but reduced RoCoF and nadir. In this control design, prioritizing a minimal frequency deviation was favored over a rapid response to ensure robust grid stability. To achieve these performance objectives, the virtual inertia coefficient and damping constant of the VSG were parameterized as $J = 10$ and $D = 50$, respectively.

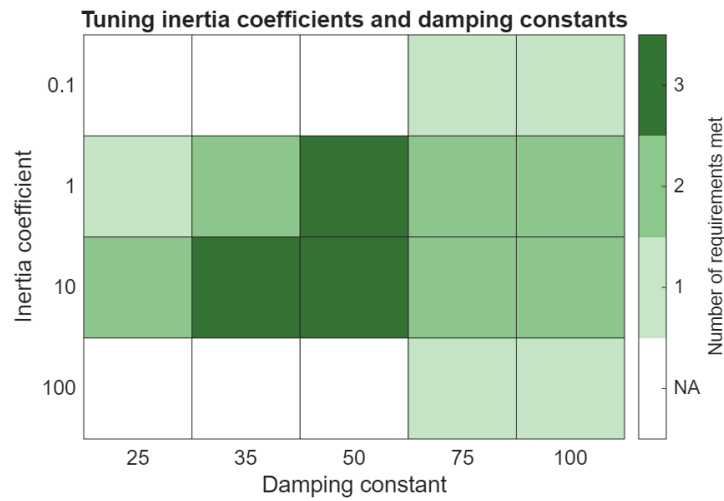


Figure 7.15: The number of frequency requirements met at different damping and inertia coefficients

J (kg · m ²)	D (N · m · s/rad)	RoCoF (Hz/s)	Frequency deviation (Hz)	Settling time (seconds)
10	35	0.21	0.89	22
	50	0.19	0.76	25
1	50	0.39	0.95	28

Table 7.4: The three inertia and damping parameter combinations that meet all requirements

It is further evident from Figure 7.15 that, for inertia values of $J = 0.1$ and $J = 100$ in combination with damping constants $D = 50$, $D = 35$ and $D = 25$, no requirements are met. In both cases this is due to the disconnection of the SG from the system.

For low inertia ($J = 0.1$), the frequency exhibits high fluctuations as a result of large RoCoF. This behavior is illustrated in Figure 7.16a. In this figure, the load connected to the grid decreases from 25 to 5 kVA. The frequency therefore increases, however, when the frequency returns to its steady state value it starts to fluctuate significantly causing the SG to disconnect at $t=15$ seconds. Following this event, the ESS supplies the required load power, settling at a new steady state frequency of 49.7 Hz.

The effect of excessive inertia is presented in Figure 7.16b, which depicts the power supplied by the ESS during a load decrease from 20 kVA to 5 kVA. It can be observed that, at high inertia levels, the power oscillates and overshoots its equilibrium value of 0 kW. Specifically, the ESS supplies up to 9 kW,

exceeding the required active load power of 4.5 kW, as observed at $t=50$ seconds. This excess power is absorbed by the SG. However, the SG only has limited capacity to do so. This capacity is exceeded at $t=52$ seconds and the SG disconnects. Subsequently, the remaining load of 4.5 kW is entirely supplied by the ESS.

These results indicate that selecting damping constants below 35 in combination with excessively high or low inertia leads to instability. This instability is either because the large RoCoF causes frequency fluctuations or because of the large power oscillations, both resulting in disconnection of the SG.

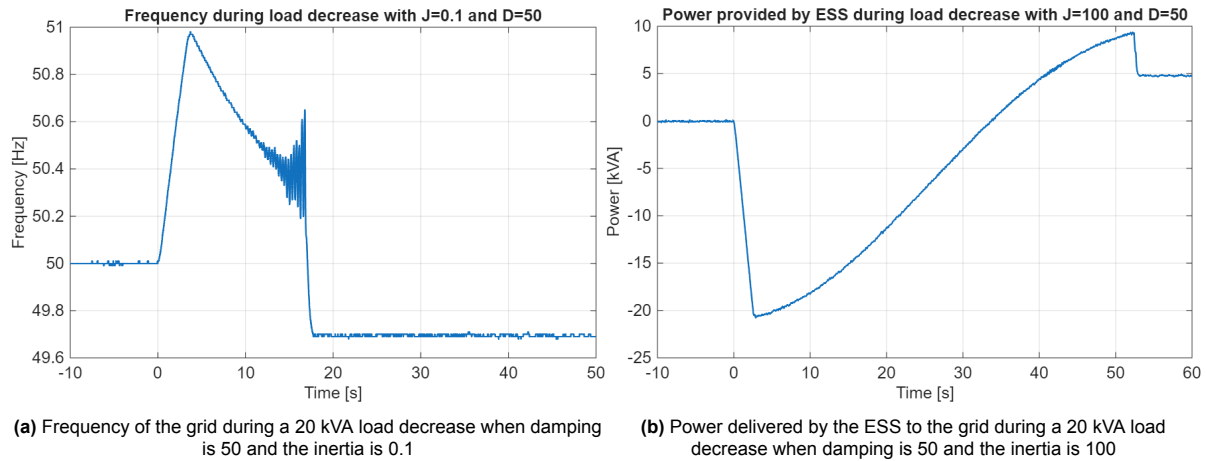


Figure 7.16: The effect of a wrongly tuned inertia on the grid frequency and power

Based on the data available in Appendix E an analysis of the effect of the inertia and damping constants can be derived. Figure 7.17 shows the settle time, frequency deviation and RoCoF during a load increase of 20 kVA at a rate of 6 kVA/s for different inertial and damping parameters. In Figure 7.17a the response time and frequency deviation is shown for $J = 10$, at different damping constants. It is evident from the figure that as the damping constant increases the settling time increases, but the frequency deviation decreases. Figure 7.17b show the RoCoF at different inertia coefficients while the damping constant is kept at 75. From this figure it is evident that as the inertia of the system increases the RoCoF decreases.

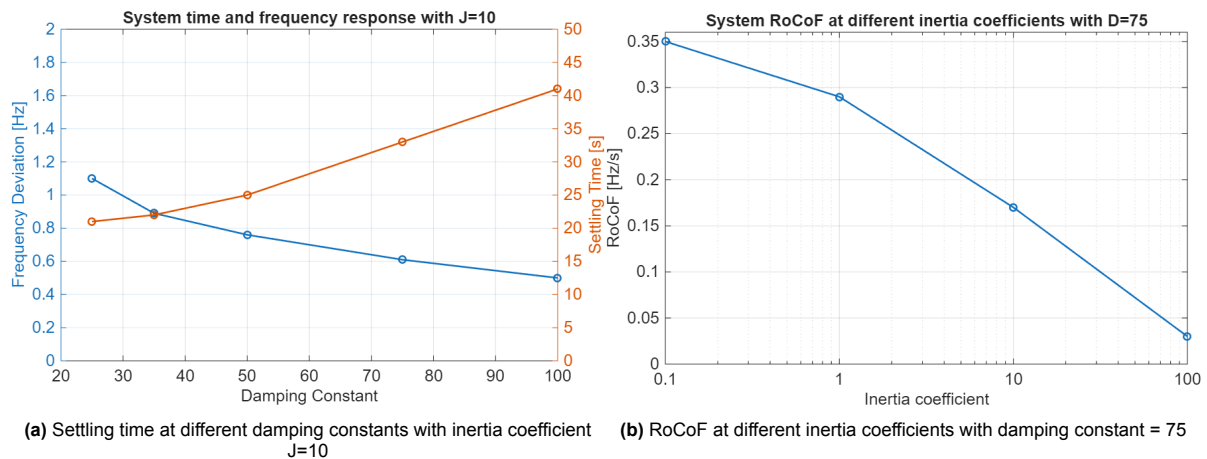


Figure 7.17: The effect of tuning J and D on the frequency of the system

7.4. Comparing simulation and testing

By comparing the results of the VSG implementation in simulation and experimental testing, the strengths and limitations of the simulation model can be identified. Firstly, the grid frequency response during

a load change is analyzed, as shown in Figure 7.18a. In the simulation, the frequency deviation is both smaller and shorter compared to the experimental results. Specifically, the simulated frequency dip is approximately 0.1 Hz and the system settles within 1.8 seconds. In contrast, during testing, the frequency drops by approximately 0.78 Hz and requires around 30 seconds to reach steady state. This discrepancy is primarily due to the model of the SG.

To further investigate this, Figure 7.18b shows the grid frequency response to a load change without the virtual inertia implementation, allowing direct observation of the SG behavior. During testing, the frequency decreases to approximately 46 Hz, whereas in the simulation the frequency decreases to 49.98 Hz. Additionally, the response time in the experiment is around 7 seconds, compared to only 0.2 seconds in the simulation. These results indicate that the SG model exhibits idealized dynamics and does not accurately capture the system behavior, particularly with respect to inertia characteristics.

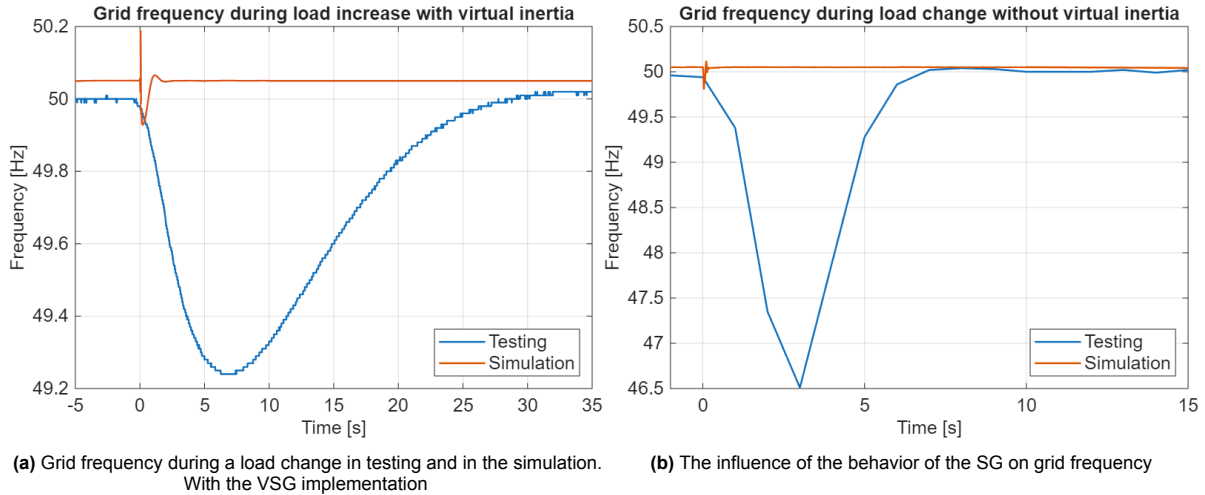


Figure 7.18: Comparison of grid frequency during a load change during testing and in simulation

Furthermore, a steady-state frequency offset is observed between simulation and experiment. In the simulation, the steady-state frequency stabilizes at approximately 50.05 Hz, while during testing the system returns to 50 Hz. This discrepancy leads to a steady-state power difference. In the simulation, the ESS supplies approximately -5 kW, whereas during testing the power supplied by the ESS returns to zero.

Next, the voltage response in simulation and testing is compared. The voltage measured in the simulation is expressed as the peak line-to-ground voltage, whereas the voltage measured during testing is represented as the RMS line-to-line voltage. To ensure a correct comparison the simulated voltage is scaled by a factor $\sqrt{\frac{3}{2}}$.

As shown in Figure 7.19a, a discrepancy in voltage setpoints between the simulation and the experiment is observed. This behavior is mainly caused by the line impedance of the grid. To further investigate this, Figure 7.19b presents the grid voltage response to a load change with only the SG connected, allowing the SGs behavior to be analyzed. The voltage at the output of the SG is compared with the voltage after the line impedance, at PCC. The results show a voltage drop of 30 V across the line impedance in the simulation. This drop is caused by the high currents required to supply the 42.5 kVA load combined with the relatively high line impedance that is intentionally used to emulate a weak grid.

In testing the voltage drop across the line is significantly smaller, because both the line impedance is lower, and because the current is lower, as the power supplied is limited to a maximum of 25 kVA. Consequently, the PCC voltage in simulation is notably lower than in the experimental case. As a result, the VSG control in the simulation requires the ESS to provide excess reactive power which is not observed during testing.

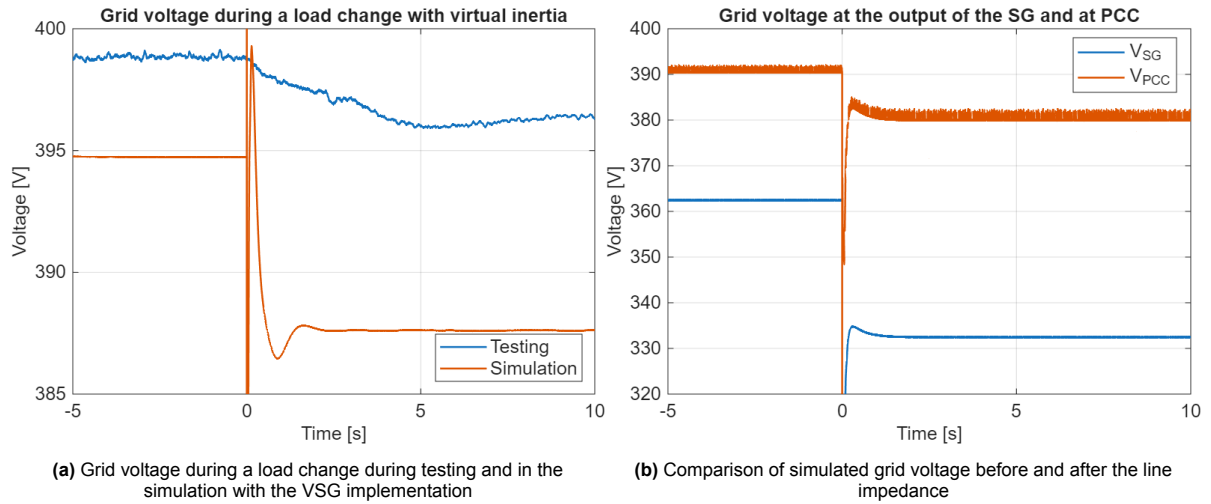
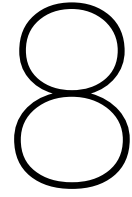


Figure 7.19: Comparison of grid voltage during a load change in simulation and testing and the voltage drop in simulation over the line impedance

In addition to the modeling inaccuracies of the SG, the simulation does not account for measurement noise and distortion in voltage and frequency signals, which can influence the system behavior and may cause drift in the operating point during testing. Despite these limitations, the simulation model remains useful for analyzing general system behavior and parameter trends. For example, it correctly demonstrates that the VSG control limits the frequency nadir, but leads to a larger frequency settling time. Additionally, the influence of changing the droop parameters k_u and k_q is clearly observable, as shown in Appendix F.2.1. However, accurate fine-tuning of these parameters should be performed experimentally, as the test setup more reliably represents the true behavior of the SG.



Discussion

This chapter discusses the test results of the developed control scheme. The advantages and limitations of the VSG control are identified and potential improvements are proposed. In addition, the assumptions and simplifications made during the study are addressed, and the relevance of the VSG control in practical applications is evaluated.

8.1. Effectiveness of VSG control

The results show that the VSG implementation is beneficial for improving frequency stability in a ship-board microgrid. This is evident from a 78% improvement in frequency nadir and 85% improvement in RoCoF as shown in Figure 7.8a. More specifically, the virtual inertia implementation is beneficial for load changes at a rate faster than 1 kVA/s. The virtual inertia implementation is hence beneficial in weak microgrids exposed to rapid load fluctuations. All frequency measurements including RoCoF, frequency nadir, frequency peak and frequency settling time fall within the requirements. However, it is important to note that the frequency settling time of the system increases with the virtual inertia implementation. As mentioned earlier, this is in response to limiting the RoCoF. The settling time can be improved by tuning the damping constant and inertia coefficient, at the expense of a larger frequency deviation. Improving settling time would be beneficial, as it reduces the time the system spends in an unstable state, where it is more vulnerable to further disturbances.

Furthermore, with the implementation of VSG control, the grid voltage deviation is reduced by 60%. This improvement is observed for load variations occurring at rates of 2.5 kVA/s or higher, as illustrated in Figure 7.9a. The voltage regulation is achieved through the reactive power control loop, which incorporates an integral droop mechanism. The droop constants were selected such that the voltage deviation remains within the requirements. However, the large voltage droop constant required to meet the constraints, results in the ESS supplying the majority of the reactive power. This behavior is undesirable, as it would require significantly over-sizing the ESS. Therefore, while the implemented voltage control is beneficial for improving voltage stability, it introduces a trade-off between voltage deviation and reactive power sharing. Further investigation into alternative droop constants and droop control strategies is recommended to ensure voltage requirements are met while enabling the reactive power contribution of the ESS to return to zero in steady-state.

8.2. Islanded vs grid-connected mode

In both scenarios explained in Chapter 2.1.1, the requirements are met. In islanded mode the converter implementation both in testing and simulation maintains the 50 Hz frequency and acceptable voltage deviation. Maintaining the frequency at its 50 Hz setpoint is achieved by setting the reference power correctly. This reference power is set by a PI controller, which determines the power required to resolve the frequency deviation caused by a load change. The PI controller is tuned aggressively, as evident in Figure 7.4a. However, this does not significantly influence the steady state output power. The voltage requirements are also met, with the voltage deviating by only 0.189%. It is however important to note

that the voltage droop constant is tuned to be more stiff. In islanded mode, the droop constant can be tuned more aggressively as all the reactive power for the load is produced by the ESS. In grid connected mode there is a trade-off between voltage deviation and reactive power production, as the reactive power produced by the ESS ideally returns to zero.

In the grid-connected mode the converter reduces the frequency fluctuation during the load transient by compensating for the power deficit or surplus. In steady state, no active power is provided to the grid from the ESS. The voltage dip is also mitigated with the reactive power control. The converter successfully fulfills its role in both modes. However, switching between modes must still be done manually by selecting the reference power and changing the droop constant.

8.3. Limitations

The proposed VSG implementation successfully satisfies the voltage and frequency requirements. However, a critical operational trade-off is observed. Although the active power contribution from the ESS decays to zero following a load change, the reactive power supplied remains at a relatively high value. This offset is a consequence of tuning the voltage droop to achieve the voltage requirements. However, tuning this droop so aggressively causes the reactive power delivered to the load by the ESS to remain at 6 kVar. Furthermore, the SG operates under an isochronous governing mechanism, maintaining a constant frequency reference. Although functional for this scenario, this control topology presents significant scalability limitations for larger microgrids featuring more parallel SGs. In a multi-generator architecture, minor deviations between frequency setpoints would induce severe control conflicts, potentially leading to system instability. Lastly, the J and D parameters require precise tuning for the system. Tuning these parameters incorrectly can lead to the SGs disconnecting.

To mitigate these limitations, an improvement to the control scheme could be to tune the voltage droop constant to $k_u = 20$ such that the voltage dips 2 V more, but the reactive power returns to zero. Alternatively a comparison between the different types of droop control could result in a solution with a smaller tradeoff. Additionally, an improvement would be to adjust the frequency setpoint of the active power control loop such that it can operate in a droop control instead of isochronous control mode, making it more scalable. Furthermore, the J and D tuning methods can be made dynamic by, for example, fuzzy tuning algorithms. By doing this the parameters can adapt to the system's response [12].

8.4. Model assumptions and simplifications

When tuning the PI controller of the inner voltage and current control loops several assumptions were made. Firstly, an infinite bus topology was used and the SGs were modeled as an ideal voltage source. Secondly, the grid impedance is assumed to be constant. In reality, the grid impedance changes depending on the loads, the number of generators connected to the grid and temperature of the wires. As the pole-zero cancellation tuning method was used and the constants are tuned based on the grid impedance, a small variation in impedance can affect the response of the system. The effectiveness of the inner voltage and current control loops was evaluated only through simulation, as these control functions were already integrated within the ABB drives during experimental testing.

Furthermore, it is important to consider the selection of the ESS for this application. This choice should be based on a trade-off between energy density and power density. Energy density signifies the size of the storage system, while power density defines how quickly a system can release or absorb energy. If the focus lies on the islanded mode capabilities of the ESS, a higher energy density is preferred, while for large varying load conditions, in the grid-connected mode, a higher power density is preferred [8].

The implementation of virtual inertia through VSG control is effective in enhancing stability in weak grids, such as microgrids with high converter penetration. It is especially beneficial under rapid load variations, where the VSG can mitigate frequency and voltage deviations. This makes the approach relevant for application on shipboard microgrids, where large and sudden load changes are inherent to system operation. Furthermore, with the anticipated increase in RES, a reduction in physical inertia within power systems is inevitable. In this context, VSG control offers a practical solution by emulating the inertial response of conventional SGs, thereby contributing to improved system stability. Consequently, the adoption of VSG-based control strategies is expected to play a key role in enabling reliable and stable operation of future low-inertia power systems.

Conclusion and future work

This study addressed the primary research question: *What is the value of implementing inertia virtually to the stability of a ship's microgrid?* The results demonstrate that implementing virtual inertia through a VSG control strategy enhances performance for both voltage and frequency stability. Key frequency and voltage stability indicators, including RoCoF, frequency nadir and voltage deviation, remain within acceptable limits. This indicates improved system response during load transients. The ESS plays a critical role in this improvement, as it can respond more rapidly to power imbalances compared to a conventional SG, thereby reducing RoCoF. Consequently, VSG control has the greatest impact during fast load transients, while for slower disturbances its contribution is limited. Furthermore, the control scheme enables operation in islanded mode, which ensures that in the absence of the SGs the converter can maintain the grid frequency at 50 Hz and grid voltage at ~ 400 V.

The second research question, *How is frequency stability defined?*, was addressed by identifying three categories of power system stability. These are rotor angle stability, frequency stability and voltage stability. Frequency stability was further characterized using two key metrics: frequency nadir and RoCoF. Their relationship was examined highlighting that system inertia determines the RoCoF, which subsequently influences frequency nadir.

The third research question, *Why are grid forming instead of grid following converters becoming more important in microgrids?* was addressed by comparing the GFM and GFL abilities. From this comparison it was evident that the switch from GFL to GFM control strategies is based mainly on the ability of a GFM converter to establish its own voltage and frequency reference. This capability facilitates the implementation of advanced grid-supporting strategies such as virtual inertia.

Additionally, the fourth research question, *How does VSG control help stabilize frequency?*, was answered through the testing results. The implementation of virtual inertia led to substantial improvements, with frequency nadir improving by 78% and the RoCoF improving by 85%. These results confirm that the VSG control mitigates frequency deviations by rapidly compensating power mismatches during load changes. This is achieved, because the response of the converter to a load change is faster than that of a conventional SG.

Furthermore, the fifth research question, *How is virtual inertia based on an ESS implemented in a grid-tied converter?*, was answered by detailing the control design and tuning methodology. Virtual inertia was implemented by embedding the swing equation in the active power control loop. The resulting frequency reference was then used in the Park transform to synchronize the dq reference frame. The PI controllers were tuned based on a developed system model.

Lastly the research question, *What are the advantages and disadvantages of implementing inertia virtually* was explored and summarized. The main advantages include reduced frequency nadir, lower RoCoF, decreased voltage dips, and improved steady-state voltage regulation. However, drawbacks such as increased settling time, trade-offs in tuning the droops constants, sensitivity to the tuning of inertia and damping parameters, and the potential for oscillatory behavior must be considered. Additionally,

the effectiveness of the control is limited for slower load changes.

This research demonstrates that VSG-based virtual inertia, implemented via an ESS connected through a VSC, provides a practical solution for mitigating frequency instability in shipboard microgrids subjected to fast load transients. Furthermore, it shows how the inner and outer control loops can be tuned based on system parameters, as well as the impact of inertia and damping parameter selection. These findings are particularly relevant for modern vessels with increasing electrification and hybridization, where the introduction of RES reduces system inertia and rapid load variations are common. For system integrators, this approach represents a viable solution for enhancing system stability.

The results in this study are subject to certain limitations. The system model was simplified to tune the inner control loops. However, in the test setup solely the outer control loops were tested. As a result the full impact of the model's assumptions has not been captured. Based on these findings and limitations, several recommendations for future work can be identified.

9.1. Future Work

This work presents a foundational implementation of a VSG control loop for a VSC interfacing an ESS. To further improve the control scheme and make it more complete, the following additional adaptations and research investigations may be considered:

- Further investigation into alternative droop control strategies and their impact on system response is recommended. Such approaches could enable improved reactive power control, ensuring that voltage remains within acceptable limits while maintaining a zero reactive power setpoint.
- Extensive research on the type of ESS for this application is advised. This should consider factors such as settling time, energy density, power density and integration complexity.
- Develop an additional outer control loop that accounts for the capacity and SOC of the ESS. Incorporating these constraints would provide a more complete representation of the system's operation.
- Extend the VSG control scheme to converters interfacing RES within the microgrid. In this configuration the dc-link energy storage can be used to accommodate quick load changes, potentially eliminating the need for an ESS. For this implementation adaptive tuning of the J and D parameters should be investigated.
- Enable autonomous switching between islanded mode and grid-connected mode. This could be achieved by detecting when a SG disconnects.
- Validate the controller by testing using realistic ship load profiles to better assess performance.

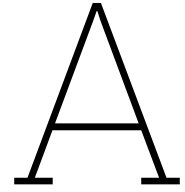
Overall, virtual inertia is a promising solution for improving stability in low-inertia power systems. The VSG control emulates the SG dynamics and by doing so enhances system resilience to disturbances and improves performance during rapid load changes. As power systems transition towards a higher penetration of RES, such control strategies will play a crucial role in ensuring reliable and robust operations of future shipboard power systems.

References

- [1] Abualkasim Bakeer et al. "Enhancing Grid-Forming Converters Control in Hybrid AC/DC Microgrids Using Bidirectional Virtual Inertia Support". en. In: *Processes* 12.1 (Jan. 2024), p. 139. ISSN: 2227-9717. DOI: 10.3390/pr12010139. URL: <https://www.mdpi.com/2227-9717/12/1/139> (visited on 03/09/2026).
- [2] Salvatore D'Arco and Jon Are Suul. "Equivalence of Virtual Synchronous Machines and Frequency-Droops for Converter-Based MicroGrids". en. In: *IEEE Transactions on Smart Grid* 5.1 (Jan. 2014), pp. 394–395. ISSN: 1949-3053, 1949-3061. DOI: 10.1109/TSG.2013.2288000. URL: <http://ieeexplore.ieee.org/document/6683080/> (visited on 11/28/2025).
- [3] Robert W. Erickson and Dragan Maksimović. *Fundamentals of Power Electronics*. en. Cham: Springer International Publishing, 2020. DOI: 10.1007/978-3-030-43881-4. URL: <http://link.springer.com/10.1007/978-3-030-43881-4> (visited on 02/21/2026).
- [4] Xian Gao et al. "Stability Analysis of Grid-Following and Grid-Forming Converters Based on State-Space Modelling". en. In: *IEEE Transactions on Industry Applications* 60.3 (May 2024), pp. 4910–4920. ISSN: 0093-9994, 1939-9367. DOI: 10.1109/TIA.2024.3353158. URL: <https://ieeexplore.ieee.org/document/10398460/> (visited on 02/19/2026).
- [5] Xinhai Guo et al. "Performance and multi-objective optimization of a ship-integrated internal wave energy conversion system". en. In: *Renewable Energy* 263 (May 2026), p. 125413. ISSN: 09601481. DOI: 10.1016/j.renene.2026.125413. URL: <https://linkinghub.elsevier.com/retrieve/pii/S0960148126002387> (visited on 06/21/2026).
- [6] *IEEE Guide for the Design and Application of Power Electronics in Electrical Power Systems on Ships*. en. ISBN: 9780738158402. DOI: 10.1109/IEEESTD.2009.4804134. URL: <https://ieeexplore.ieee.org/document/4804134/> (visited on 03/03/2026).
- [7] Mahmood Jafari, Gevork B. Gharehpetian, and Amjad Anvari-Moghaddam. "On the Role of Virtual Inertia Units in Modern Power Systems: A Review of Control Strategies, Applications and Recent Developments". In: *International Journal of Electrical Power & Energy Systems* 159 (Aug. 2024), p. 110067. ISSN: 0142-0615. DOI: 10.1016/j.ijepes.2024.110067. URL: <https://www.sciencedirect.com/science/article/pii/S0142061524002886> (visited on 11/28/2025).
- [8] Shantha Jayasinghe et al. "Review of Ship Microgrids: System Architectures, Storage Technologies and Power Quality Aspects". en. In: *Inventions* 2.1 (Feb. 2017), p. 4. ISSN: 2411-5134. DOI: 10.3390/inventions2010004. URL: <https://www.mdpi.com/2411-5134/2/1/4> (visited on 03/04/2026).
- [9] John J. Grainger and William D. Stevenson. *Power System Analysis*. McGraw-Hill, 1994.
- [10] Karl J Astrom, Bjorn Wittenmark. *Computer Controlled Systems*. en. 3rd. Printice Hall.
- [11] Thongchart Kerdphol et al. *Virtual Inertia Synthesis and Control*. en. Power Systems. Cham: Springer International Publishing, 2021. URL: <http://link.springer.com/10.1007/978-3-030-57961-6> (visited on 06/07/2026).
- [12] Mohammad-Hassan Khooban et al. "Shipboard Microgrids: A Novel Approach to Load Frequency Control". en. In: *IEEE Transactions on Sustainable Energy* 9.2 (Apr. 2018), pp. 843–852. ISSN: 1949-3029, 1949-3037. DOI: 10.1109/TSTE.2017.2763605. URL: <http://ieeexplore.ieee.org/document/8069010/> (visited on 12/01/2025).
- [13] Jia Liu, Yushi Miura, and Toshifumi Ise. "Comparison of Dynamic Characteristics Between Virtual Synchronous Generator and Droop Control in Inverter-Based Distributed Generators". en. In: *IEEE Transactions on Power Electronics* 31.5 (May 2016), pp. 3600–3611. ISSN: 0885-8993, 1941-0107. DOI: 10.1109/TPEL.2015.2465852. URL: <http://ieeexplore.ieee.org/document/7182342/> (visited on 02/19/2026).

- [14] Chalitha Liyanage, Inam Nutkani, and Lasantha Meegahapola. "A Comparative Analysis of Prominent Virtual Synchronous Generator Strategies Under Different Network Conditions". en. In: *IEEE Open Access Journal of Power and Energy* 11 (2024), pp. 178–195. ISSN: 2687-7910. DOI: 10.1109/OAJPE.2024.3384354. URL: <https://ieeexplore.ieee.org/document/10488377/> (visited on 11/27/2025).
- [15] Martin J Hoeijmakers. *Modelling of AC machines*. Apr. 2004.
- [16] National Energy System Operator. *The grid code*. Apr. 2026. URL: <https://dcm.neso.energy/> (visited on 05/18/2026).
- [17] Jungang Nie. "Research on Stability of New Energy Ship Power System Based on VSG Control". en. In: *2024 4th International Conference on New Energy and Power Engineering (ICNEPE)*. Guangzhou, China: IEEE, Nov. 2024, pp. 210–214. ISBN: 979-8-3315-1608-6. DOI: 10.1109/ICNEPE64067.2024.10860299. URL: <https://ieeexplore.ieee.org/document/10860299/> (visited on 02/19/2026).
- [18] Evaggelia Nivolianiti, Yannis L. Karnavas, and Jean-Frederic Charpentier. "Energy management of shipboard microgrids integrating energy storage systems: A review". en. In: *Renewable and Sustainable Energy Reviews* 189 (Jan. 2024), p. 114012. ISSN: 13640321. DOI: 10.1016/j.rser.2023.114012. URL: <https://linkinghub.elsevier.com/retrieve/pii/S1364032123008705> (visited on 05/10/2026).
- [19] Katsuhiko Ogata. "Modern Control Engineering". en. In: *Pearson* (), p. 894.
- [20] P. C. Sen. *Principles of Electrical Machines and Power Electronics*. Wiley. ISBN: 978-1-118-07887-7.
- [21] Prabha Kundur. *Power system stability*. McGraw Hill. ISBN: 978-1-260-47354-4.
- [22] Qing-Chang Zhong et al. "Self-Synchronized Synchronverters: Inverters Without a Dedicated Synchronization Unit". en. In: *IEEE Transactions on Power Electronics* 29.2 (Feb. 2014), pp. 617–630. ISSN: 0885-8993, 1941-0107. DOI: 10.1109/TPEL.2013.2258684. URL: <http://ieeexplore.ieee.org/document/6504534/> (visited on 05/02/2026).
- [23] Enrique Rodriguez-Diaz et al. "Analysis and Comparison of Notch Filter and Capacitor Voltage Feedforward Active Damping Techniques for LCL Grid-Connected Converters". en. In: *IEEE Transactions on Power Electronics* 34.4 (Apr. 2019), pp. 3958–3972. ISSN: 0885-8993, 1941-0107. DOI: 10.1109/TPEL.2018.2856634. URL: <https://ieeexplore.ieee.org/document/8411490/> (visited on 05/12/2026).
- [24] Wenju Sang et al. "Virtual Synchronous Generator, a Comprehensive Overview". en. In: *Energies* 15.17 (Aug. 2022), p. 6148. ISSN: 1996-1073. DOI: 10.3390/en15176148. URL: <https://www.mdpi.com/1996-1073/15/17/6148> (visited on 05/06/2026).
- [25] Fehmi Sevilmiş and Hulusi Karaca. "Performance analysis of SRF-PLL and DDSRF-PLL algorithms for grid interactive inverters". en. In: *International Advanced Researches and Engineering Journal* 3.2 (Aug. 2019), pp. 116–122. ISSN: 2618-575X. DOI: 10.35860/iarej.412250. URL: <http://dergipark.org.tr/en/doi/10.35860/iarej.412250> (visited on 06/10/2026).
- [26] Ujjwol Tamrakar et al. "Virtual Inertia: Current Trends and Future Directions". en. In: *Applied Sciences* 7.7 (June 2017), p. 654. ISSN: 2076-3417. DOI: 10.3390/app7070654. URL: <https://www.mdpi.com/2076-3417/7/7/654> (visited on 11/27/2025).
- [27] Daisuke Terazono et al. "Grid Frequency Regulation Support From Back-to-Back Motor Drive System With Virtual-Synchronous-Generator-Based Coordinated Control". en. In: *IEEE Transactions on Power Electronics* 36.3 (Mar. 2021), pp. 2901–2913. ISSN: 0885-8993, 1941-0107. DOI: 10.1109/TPEL.2020.3015806. URL: <https://ieeexplore.ieee.org/document/9165015/> (visited on 11/27/2025).
- [28] M.P.N Van Wessenbeeck et al. "Grid tied converter with virtual kinetic storage". en. In: *2009 IEEE Bucharest PowerTech*. Bucharest: IEEE, June 2009, pp. 1–7. ISBN: 978-1-4244-2234-0. DOI: 10.1109/PTC.2009.5282048. URL: <https://ieeexplore.ieee.org/document/5282048/> (visited on 02/19/2026).

- [29] Pratik Vernekar et al. "Feedback Control Methods for a Single Machine Infinite Bus System". en. In: ().
- [30] Slobodan N. Vukosavic. *Grid-Side Converters Control and Design*. en. Power Electronics and Power Systems. Cham: Springer International Publishing, 2018. URL: <http://link.springer.com/10.1007/978-3-319-73278-7> (visited on 02/21/2026).
- [31] Wenli Yao et al. "Design and Analysis of Robust Active Damping for LCL Filters Using Digital Notch Filters". en. In: *IEEE Transactions on Power Electronics* 32.3 (Mar. 2017), pp. 2360–2375. ISSN: 0885-8993, 1941-0107. DOI: 10.1109/TPEL.2016.2565598. URL: <http://ieeexplore.ieee.org/document/7467545/> (visited on 05/12/2026).
- [32] Yoash Levron, Juri Belikov. *The Direct-Quadrature-Zero (DQ0) Transformation*. URL: https://a-lab.ee/sites/default/files/PS_Lecture_2.pdf.



Mathematical derivation of the dq-reference frame coupling

The derivative of a d-axis components causes cross-coupling with the q-axis and vice versa. This is mathematically presented in the following formulae.

$$\frac{dX_{dq}}{dt} = \frac{dX_{dq}e^{-j\omega t}}{dt} \quad (\text{A.1})$$

$$= e^{-j\omega t} \frac{dX_{dq}}{dt} - jX_{dq} \frac{d\omega t}{dt} e^{-j\omega t} \quad (\text{A.2})$$

$$\dot{X}_d = X_d + \omega X_q \text{ and } \dot{X}_q = X_q - \omega X_d \quad (\text{A.3})$$

B

Cross-coupling

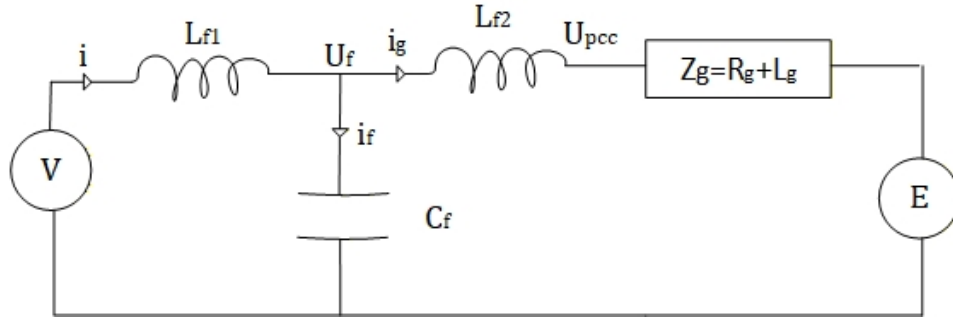


Figure B.1: The model from figure 4.1 simplified

$$\begin{bmatrix} \dot{i}_{gd} \\ \dot{i}_{gq} \\ \dot{U}_{fd} \\ \dot{U}_{fq} \end{bmatrix} = \begin{bmatrix} \frac{1}{L_{f2} + L_g} & 0 & \frac{-R_g}{L_{f2} + L_g} & \omega_g \\ 0 & \frac{1}{L_{f2} + L_g} & -\omega_g & \frac{-R_g}{L_{f2} + L_g} \\ \frac{-1}{C_f} & 0 & 0 & \omega_g \\ 0 & \frac{-1}{C_f} & -\omega_g & 0 \end{bmatrix} \begin{bmatrix} i_{gd} \\ i_{gq} \\ U_{fd} \\ U_{fq} \end{bmatrix} + \begin{bmatrix} \frac{1}{C_f} & 0 & 0 & 0 \\ 0 & \frac{1}{C_f} & 0 & 0 \\ 0 & 0 & \frac{-1}{L_g + L_{f2}} & 0 \\ 0 & 0 & 0 & \frac{-1}{L_g + L_{f2}} \end{bmatrix} \begin{bmatrix} i_d \\ i_q \\ E_d \\ E_q \end{bmatrix} \quad (\text{B.1})$$

By setting the current as follows, the cross-coupling term is mitigated.

$$i_d = I_{dref} - V_{pcc} \omega_g C_f \quad i_q = i_{qref} + V_{pcc} \omega_g C_f \quad (\text{B.2})$$

$$\begin{bmatrix} \dot{i}_{cd} \\ \dot{i}_{cq} \\ \dot{U}_{fd} \\ \dot{U}_{fq} \end{bmatrix} = \begin{bmatrix} \omega & 0 & \frac{-1}{L_{f1}} & 0 \\ 0 & -\omega & 0 & \frac{-1}{L_{f1}} \\ 0 & \omega & \frac{1}{C_f} & 0 \\ -\omega & 0 & 0 & \frac{1}{C_f} \end{bmatrix} \begin{bmatrix} i_{cd} \\ i_{cq} \\ U_{fd} \\ U_{fq} \end{bmatrix} + \begin{bmatrix} \frac{1}{L_{f1}} & 0 & 0 & 0 \\ 0 & \frac{1}{L_{f1}} & 0 & 0 \\ 0 & 0 & \frac{-1}{C_f} & 0 \\ 0 & 0 & 0 & \frac{-1}{C_f} \end{bmatrix} \begin{bmatrix} V_d \\ V_q \\ i_{gd} \\ i_{gq} \end{bmatrix} \quad (\text{B.3})$$

By setting the voltage as follows, the cross-coupling term is mitigated.

$$V_d = V_{dref} - I_{pcc} \omega_g L_{f1} \quad V_q = V_{qref} + I_{pcc} \omega_g L_{f1} \quad (\text{B.4})$$

C

Simulink Models

The Simulink models for the simulations are shown in this chapter. The models are represented for the initial model, the islanded mode and the grid-connected mode.

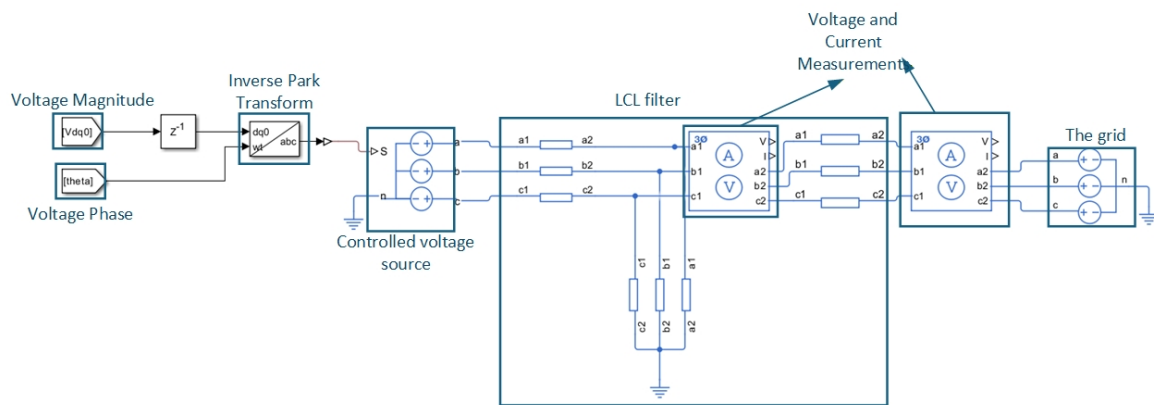


Figure C.1: Simulation model in Simulink of the system described in chapter 4

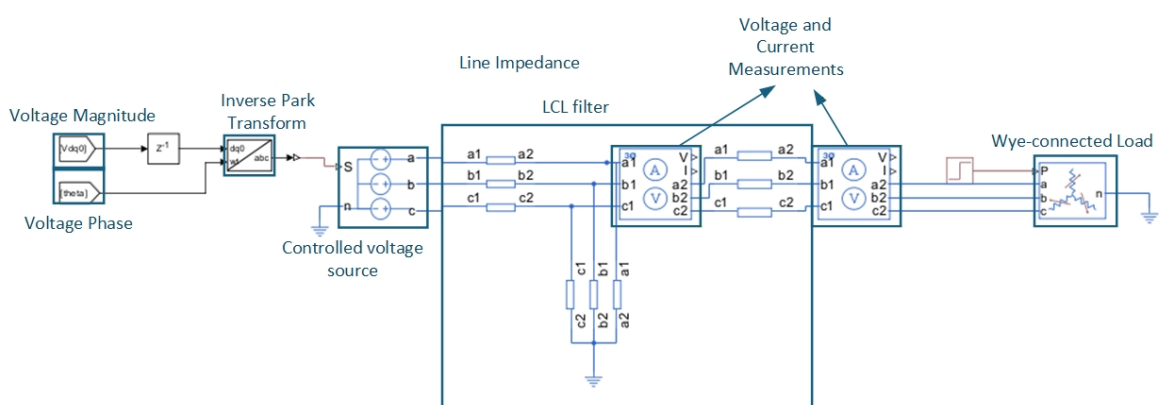


Figure C.2: Simulation model in Simulink of the converter in islanded mode

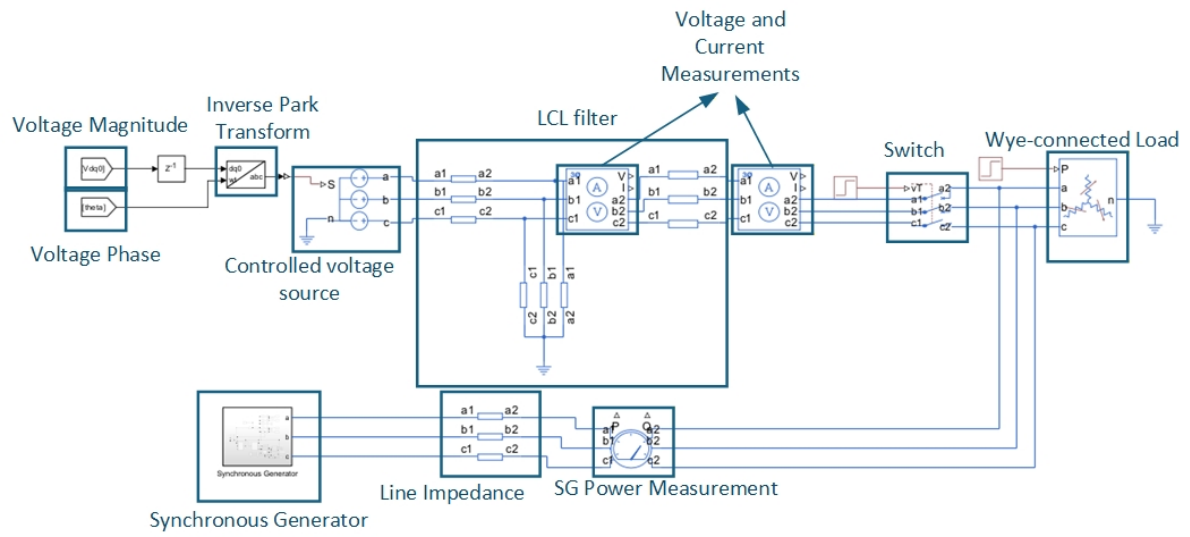


Figure C.3: Simulation model in Simulink of the converter in grid-connected mode

D

Discretization of the simple RL circuit

For the simple equivalent RL circuit as shown in figure 5.4, the state space matrix is given in equation D.2. The transformation of these matrices from the continuous domain to the discrete domain, with a sampling period of T_s , is shown in equations D.3–D.4. Here, the transition matrix ϕ and input matrix Γ are derived from the system matrices A and B [10].

$$A = \begin{bmatrix} \frac{-R_g}{L_{eq}} & 0 \\ 0 & \frac{-R_g}{L_{eq}} \end{bmatrix}, \quad B = \begin{bmatrix} \frac{1}{L_{eq}} & 0 \\ 0 & \frac{1}{L_{eq}} \end{bmatrix} \quad (\text{D.1})$$

(D.2)

$$\phi = e^A = \begin{bmatrix} e^{\frac{-R_g}{L_{eq}} T_s} & 0 \\ 0 & e^{\frac{-R_g}{L_{eq}} T_s} \end{bmatrix} \quad (\text{D.3})$$

$$\Gamma = \int_0^h e^{As} ds B = \frac{1}{R} \begin{bmatrix} 1 - e^{\frac{-R_g}{L_{eq}} T_s} & 0 \\ 0 & 1 - e^{\frac{-R_g}{L_{eq}} T_s} \end{bmatrix} \quad (\text{D.4})$$

E

Results of tuning the inertia and damping parameters

The measured frequency deviation at different inertia coefficients and damping constants is shown in the following table.

Table E.1: Frequency deviation (Hz)

	Damping constant				
J	25	35	50	75	100
0.1	-	-	-	0.7	0.56
1	1.46	1.28	0.95	0.72	0.55
10	1.1	0.89	0.76	0.61	0.5
100	-	-	-	0.37	0.32

The measured frequency settling time at different inertia coefficients and damping constants is shown in the following table.

Table E.2: Time (s)

	Damping constant				
J	25	35	50	75	100
0.1	-	-	-	36	42.47
1	18.9	22.8	28	35.6	42
10	21	22	25	33	41
100	-	-	-	88	89

The measured RoCoF at different inertia coefficients and damping constants is shown in the following table.

Table E.3: RoCoF (Hz/s)

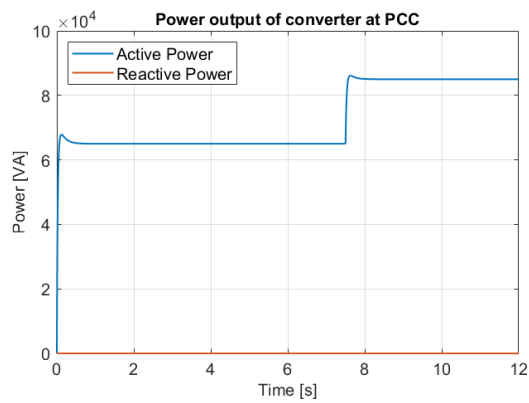
	Damping constant				
J	25	35	50	75	100
0.1	-	-	-	0.35	0.23
1	0.57	0.5	0.39	0.29	0.23
10	0.24	0.21	0.19	0.17	0.14
100	-	-	-	0.03	0.03

F

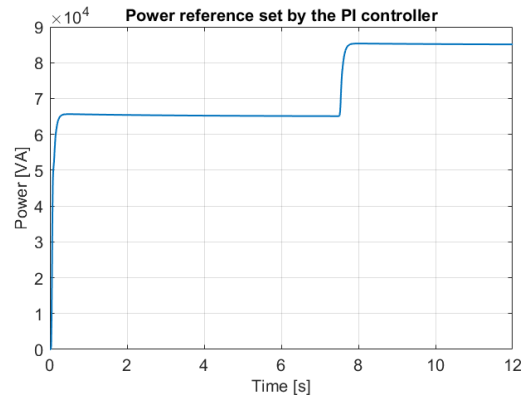
Simulation Results

F.1. Islanded mode

This chapter contains all the simulation results when simulated in islanded mode. There is a load increase of 20 kW at $t=7.5$ seconds.

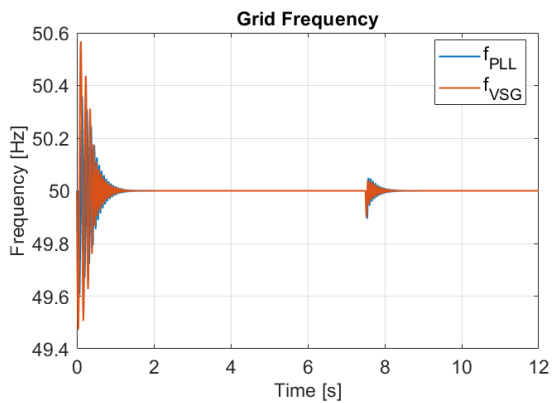


(a) The output power of the converter as measured at the PCC

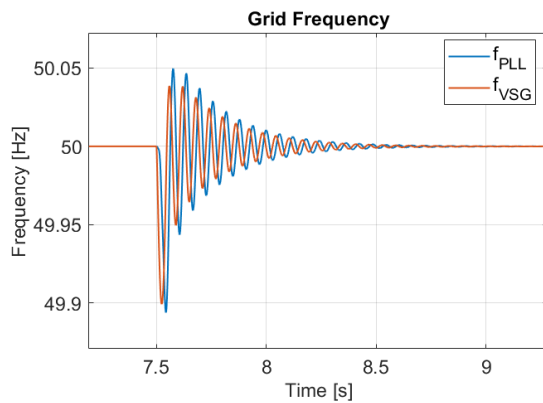


(b) The reference power set by the PI controller for the active power control loop

Figure F.1: Power delivered by the ESS



(a) The grid frequency



(b) The grid frequency zoomed in during the load change

Figure F.2: The grid frequency

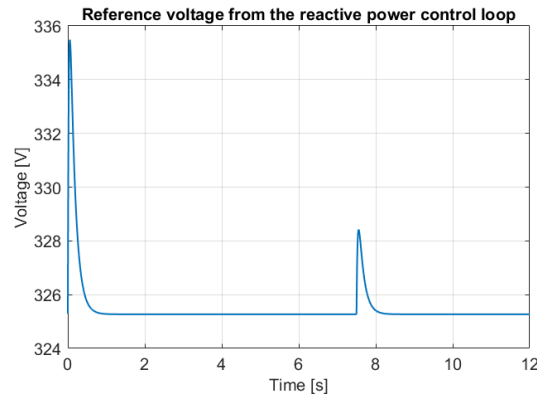
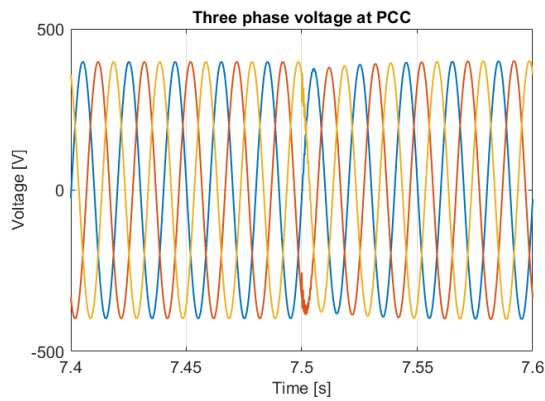
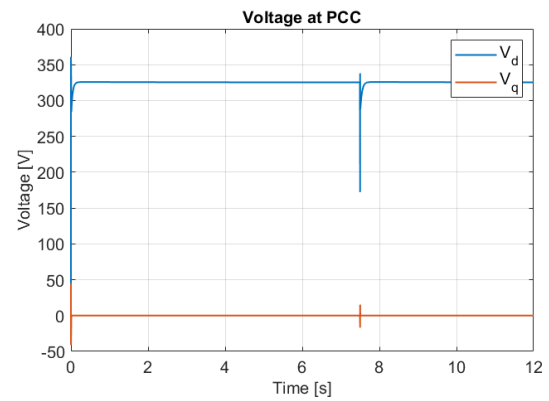


Figure F.3: The reference voltage from the reactive power control loop

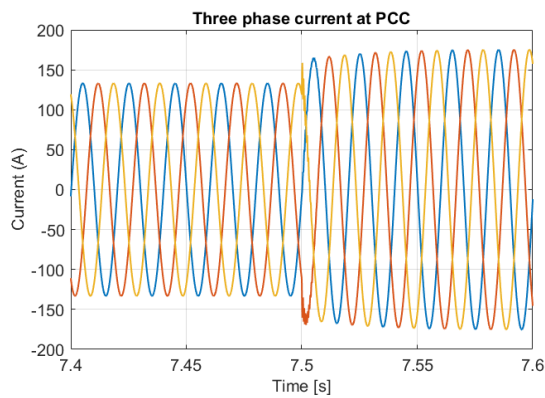


(a) The three phase output voltage of the converter measured at the PCC

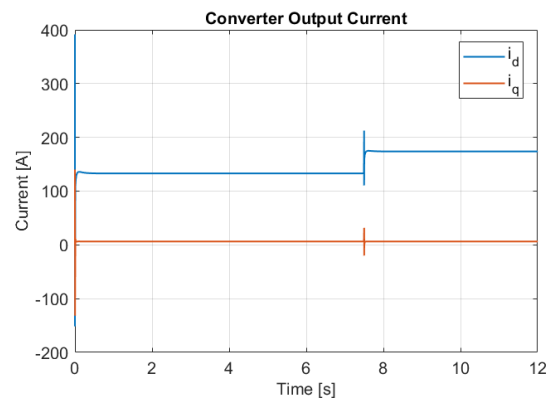


(b) The d- and q-axis components of the converter output voltage measured at the PCC

Figure F.4: The voltage at the PPC both before and after the park transformation



(a) The three phase output current of the converter measured at the PCC



(b) The d- and q-axis components of the converter output current measured at the PCC

Figure F.5: The current at the PPC both before and after the park transformation

F.2. Grid-connected

This chapter contains all the simulation results when simulated in grid-connected mode. The converter is connected at $t=2.5$ seconds. There is a load increase of 20 kVA with power factor 0.916 at $t=10$ seconds.

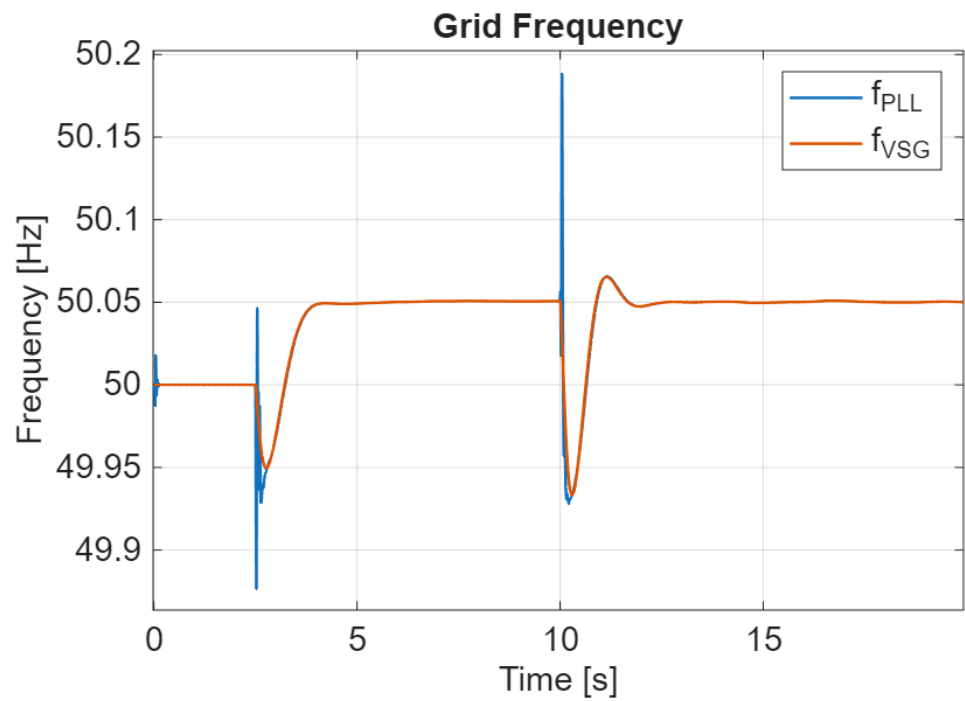


Figure F.6: Frequency of the grid

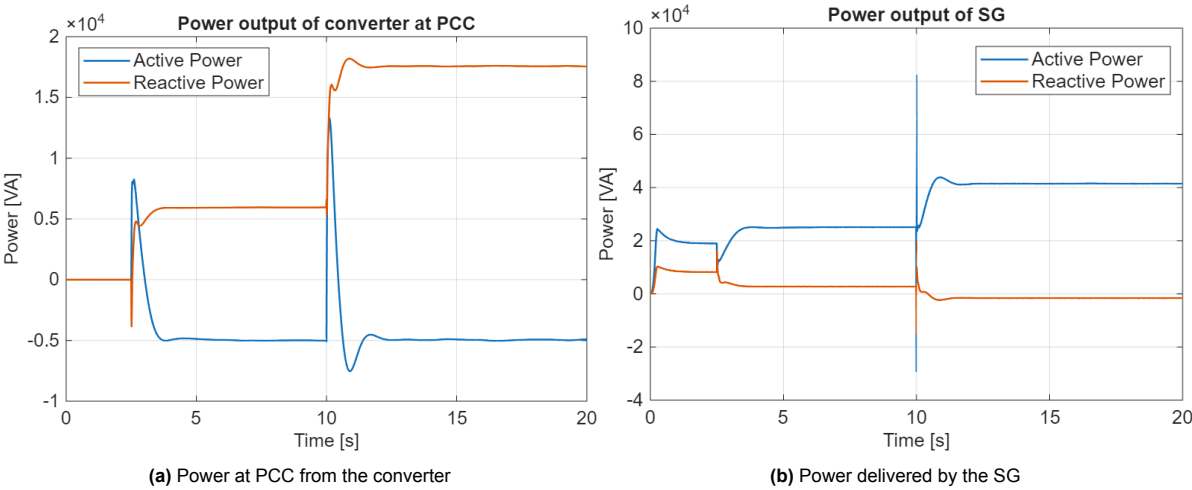


Figure F.7: Power delivered by the SG and converter during a load change

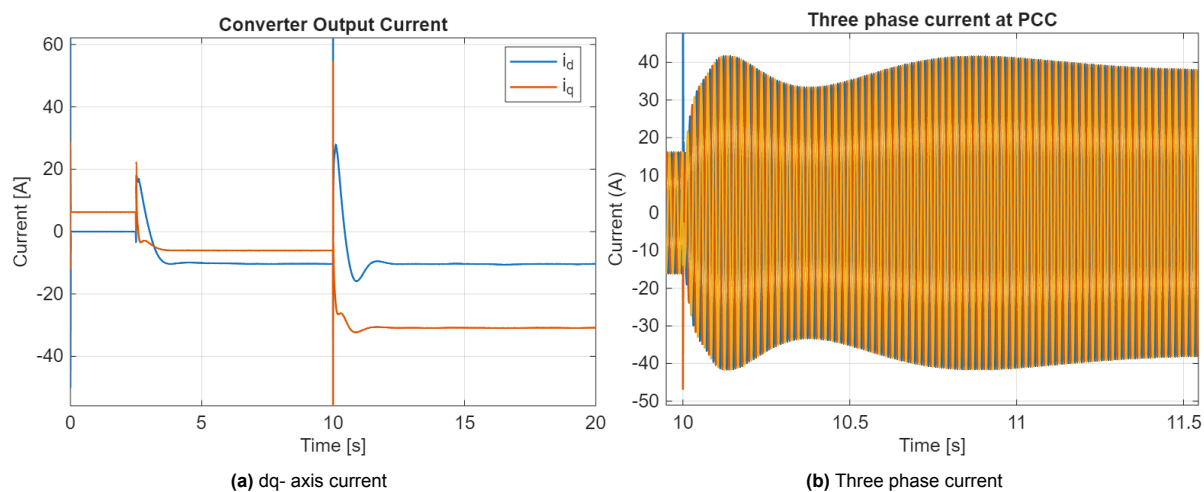


Figure F.8: Current from the converter

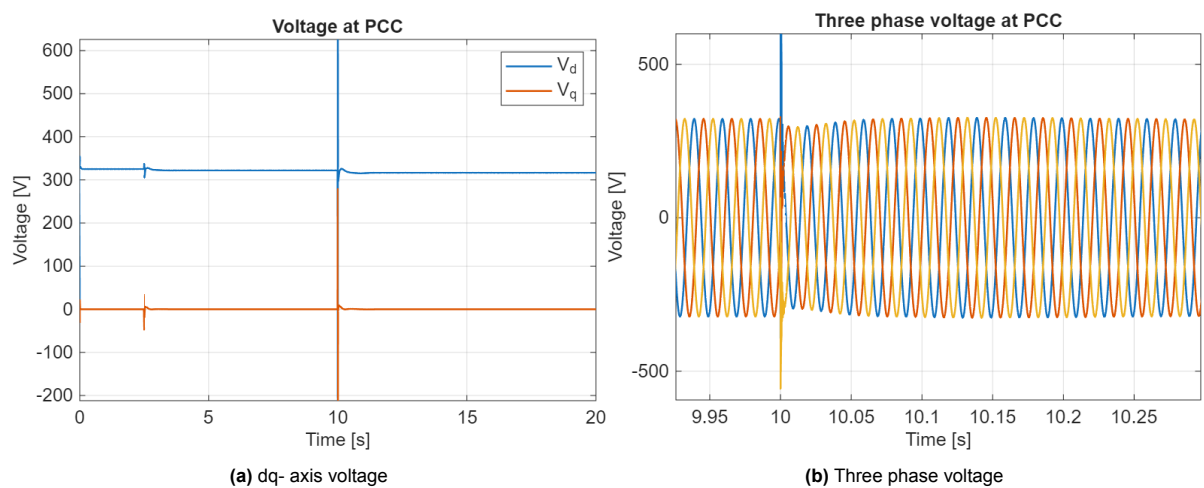


Figure F.9: Converter voltage at PCC

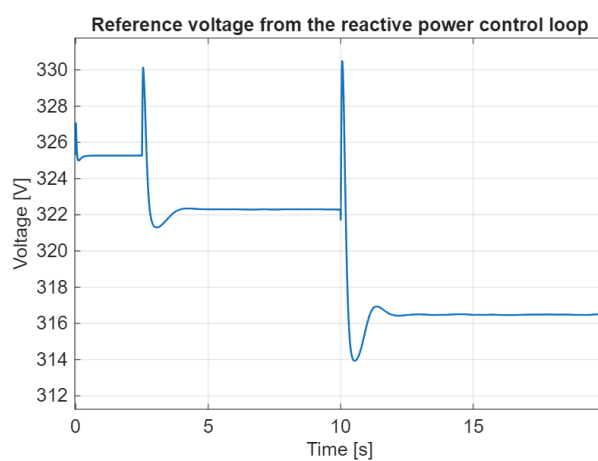


Figure F.10: Reference voltage set by the reactive power control loop

F.2.1. Tuning Reactive Power Control Loop

The reactive power control loop uses integral droop control. For this control both the voltage and reactive power droop constant, k_u and k_q can be tuned. Tuning the voltage droop constant determines the how much the reference voltage deviates from its setpoint depending on the reactive power error. A larger voltage droop constant results in a smaller voltage deviation, but requires the ESS to supply more reactive power. The reactive power droop determines the weight of the integrated error. Thus, it determines the rate at which the voltage changes. A smaller weight would mean the voltage changes with smaller steps from its rated value V_{rated} , hence a smaller rate of change of voltage. This is further proved in figure F.11b.

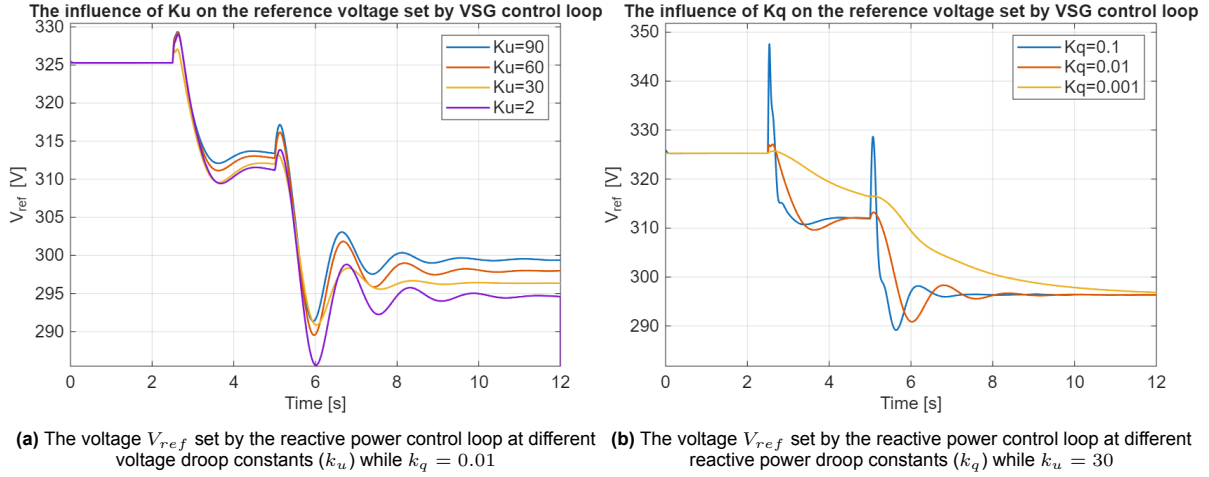


Figure F.11: The voltage V_{ref} set by the reactive power control loop at different voltage and reactive power droop constants, k_u and k_q respectively

G

Test results

The grid voltage during a load increase of 20 kVA at a power factor of 0.916 at different loading rates is shown with and without virtual inertia in Figure G.1b and Figure G.1a respectively.

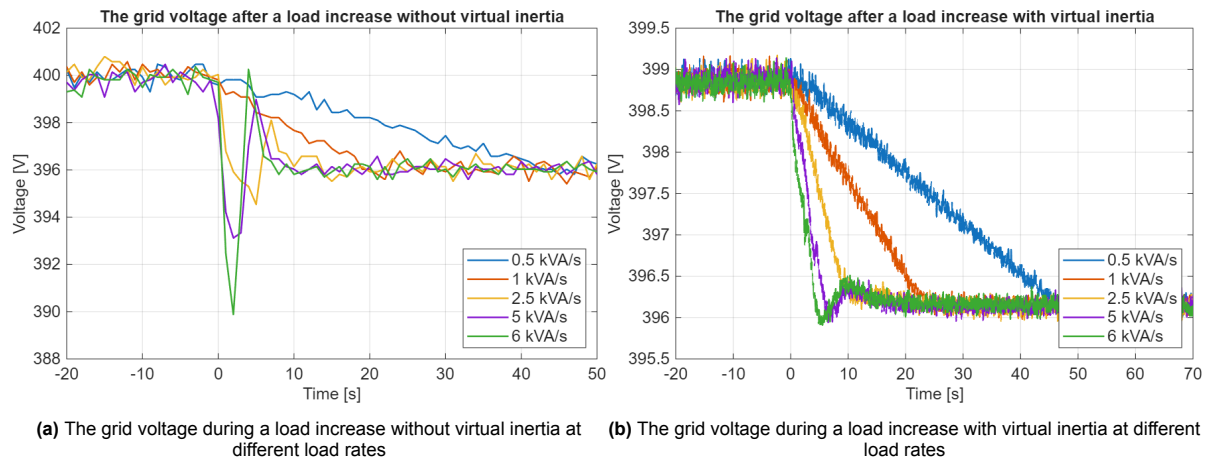


Figure G.1: The grid voltage during a load increase without and without virtual inertia at different load rates

The reactive power supplied by the ESS to maintain the voltage response as shown in Figure G.1b, is represented in Figure G.2.

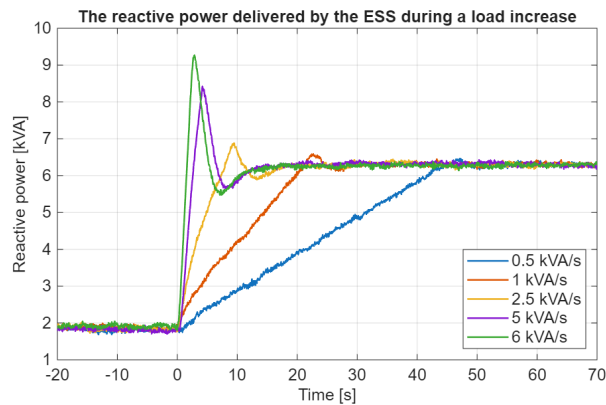


Figure G.2: Reactive power supplied by the ESS during a load increase