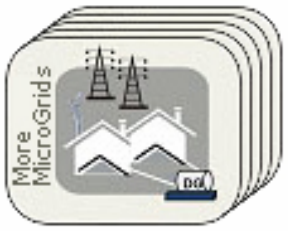

Advanced Architectures and Control Concepts for

MORE MICROGRIDS

Contract No: SES6-019864

WORK PACKAGE A

DA2. Inverter Performance with regard to Ancillary Services and Fault-Ride-Through Capabilities

Final Version

July 2008

Abstract and purpose of the document
This document analyses control capabilities of inverter-coupled generators and storage devices with regard to ancillary services (frequency control support, voltage control support, congestion management, optimisation of grid losses, improvement of power quality, and grid-forming including black start) and fault-ride-through capabilities.

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Coordination:	Martin Braun (ISET)	mbraun@iset.uni-kassel.de
Authors:	Martin Braun (ISET) Chapter 2	mbraun@iset.uni-kassel.de
	Antonio Notholt-Vergara (ISET) Chapter 3	anotholt@iset.uni-kasel.de

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Executive Summary

The electricity supply is more and more based on distributed generators (DGs) from Renewable Energy Sources (RES). Presently, they are only injecting the available active power into the interconnected network. At higher penetration levels they might jeopardise the stability of the network. In a more sophisticated approach, they should participate in network operation to guarantee a sustainable and secure electricity supply.
Particularly in Microgrids, which operate alternatingly connected to the mains or in island mode, an utilisation of control capabilities for network operation is very important. Presently, most islanded networks are formed by synchronous generator sets (esp. Diesel generators) and also battery inverters. The other DGs only inject active power. Using their control capabilities in addition supports the Microgrid's operation. The capacity of the grid-forming device may be reduced due to additional control capacity of the other DGs. Utilising the most economic control potentials of all participating units can improve the overall economics of the Microgrid. Also the supply security can be increased if more than one unit contributes to network operation.
The study at hand provides a comprehensive survey and assessment of the performance of individual inverter-coupled DG units with regard to ancillary services and Fault-Ride-Through (FRT) capabilities.
The following paragraphs summarise the resulting technological capabilities of ancillary services' provision by inverter-coupled DG units:

Ancillary Services:

- **Frequency Control Support** based on active power control can be provided by all electricity-driven DG units. Thermal-driven combined cooling, heat and power (CCHP) units are excluded because they have to follow the required thermal profile. The capability of electricity-driven CCHP[1] as well as storage units is very good because they have a high availability and flexibility. Intermittent energy systems, i.e. wind turbines, photovoltaic systems and hydro power plants can control their active power but their availability is limited.
- **Voltage Control Support, Congestion Management and Optimisation of Grid Losses** is mainly dependent on the reactive power control capability of the DG unit. Inverter- coupled DG/storage systems show a very good reactive power control capability.
- The **Improvement of Voltage (Power) Quality** is dependent on the grid-coupling converter. Inverter-coupled units can improve voltage quality, for instance, by compensating harmonics and reducing flicker by current ramp limits.
- **Grid-Forming (Islanded Operation)** requires **direct frequency and direct voltage control**. Sufficient active and reactive power control capacity is required to sustain the values. With the exception of thermal-driven CCHP plants all DGs are in principle capable of contributing to the network's operation as grid-formers. Electricity-driven CCHP plants and storage devices show very good control capabilities. Intermittent DG, i.e. photovoltaic systems, wind turbines and hydro power plants, have a lower availability and primary source fluctuations. **Black Start (Network Restoration)** needs the same control capabilities as islanded operation. In addition, it demands for a grid-independent system start. This is possible for all inverter-coupled DG units with sufficient storage to self-start (e.g. for ignition, heating up, or activating the control system).

[1] In case of electricity-driven CCHP, high temperature fuel cells can have difficulties in changing their output fast enough for frequency response.

A summary is presented in the following Table. Principally, all types of ancillary services can be provided by inverter-coupled distributed generators. Some limitations exist for thermal-driven CCHP plants (without storage devices) which do not have sufficient active power control capability to provide frequency control support and grid-forming. Also the intermittency of WTGs, PV systems and small hydro power plants restricts the availability and the active power control capability to a certain degree. Sophisticated control approaches are capable of making use of these dynamically available ancillary services.

Technological capabilities of inverter-coupled distributed generators

DG System	Storage	WTG PV Hydro	CCHP	
			(thermal-driven)	(electricity-driven)
Frequency Control Support	Yes ++	Yes +	No	Yes ++
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes ++	Yes ++	Yes +	Yes ++
Improvement of Voltage Quality	Yes ++	Yes ++	Yes ++	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	Yes ++	Yes +	No	Yes ++

Legend:
No indicates that this is not possible without additional external equipment
Yes indicates that this is possible without additional external equipment
++ indicates very good capabilities
+ indicates good capabilities

Fault-Ride-Through (FRT) capability:
Also the FRT capability is dependent on the grid-coupling converter. Inverter-based DG has an acceptable flexibility in terms of FRT because they decouple the power generation process and the grid. This flexibility comprises the phase, magnitude and even harmonic content of the currents injected.
It has however one drawback: The maximum fault current that the converter may be able to provide. While synchronous machines are usually able to provide at up to six times the nominal current during a fault, inverters are currently set to provide as much as its nominal current.
The presented investigations reveal that under specific circumstances the inverter can be able to provide up to four times its nominal current during a fault. This overloading capability depends on several factors but the most relevant is the thermal loading of the power electronics components. A higher overload capability is possible but at the cost of a lower performance under part-load conditions, or in other cases, higher volumes, weights and costs.

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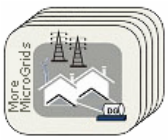
More MicroGrids
DA

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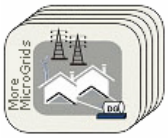
1. Introduction

In the last decade, the European Union has been deploying significant amounts of DG (Distributed Generator) units of various technologies in response to the climate change challenge and the need to enhance fuel diversity. However conventional large-scale power plants remain the primary source of control of the electricity system assuring integrity and security of its operation.
Levels of DGs' penetration in some parts of the European Union are such that DGs are beginning to cause operational challenges (e.g. in Denmark, Germany and Spain). This is because so far the emphasis has been on connecting DGs to the network rather than integrating them into overall system operation.
In practice, current policy of connecting DGs is generally based on 'fit and forget' approach. This policy is consistent with historic passive distribution network operation and is known to lead to inefficient and costly investment in distribution infrastructure. Moreover, under passive network operation, DGs can only displace the energy produced by central generation but cannot displace the capacity because the lack of controllability of Distributed Energy Resources (DER) units (including distributed generators, storage and loads) implies that system control and security must be provided by central generation further on.
In order to address this problem, DER must takeover the responsibilities from large conventional power plants and provide flexibility and controllability necessary to support secure system operation. Although Transmission Network Operators (TNOs) have historically been responsible for system security, integration of DER will require Distribution Network Operators (DNOs) to develop active network management in order to participate in the provision of system security.
The Microgrid concept builds on the required active distribution network management enhancing it with the capability of operating distribution network areas in island mode. This possibility increases the security of power supply for consumers in the respective network area. The islanded operation requires DER units to participate in the operation of the Microgrid they are connected to. But they can also provide ancillary services to the TNO.

A well-know definition for Microgrids is the following one: "Microgrids comprise Low Voltage distribution systems with distributed energy sources, such as micro-turbines, fuel cells, photovoltaic, etc., together with storage devices, i.e. flywheels, energy capacitors and batteries, and controllable loads, offering considerable control capabilities over the network operation. These systems are interconnected to the Medium Voltage Distribution network, but they can be also operated isolated from the main grid, in case of faults in the upstream network. From the customer point of view, Microgrids provide both thermal and electricity needs, and in addition enhance local reliability, reduce emissions, improve power quality by supporting voltage and reducing voltage dips, and potentially lower costs of energy supply." [Hatziargyriou et al 2006]

A comprehensive analysis of the capabilities of individual DER units in general has been performed in the framework of the European project FENIX [Braun et al. 2006]. Some of these results have been published [Braun 2007a]. This document in the framework of the European project MORE MICROGRIDS builds on these previously performed analyses. Different to those studies, we look especially at inverter-coupled DGs connected to Microgrids and their capabilities to provide ancillary services (Chapter 2). Furthermore, the inverter-coupled DGs' behaviour in case of faults is looked at in particular detail to analyse their Fault-Ride-Through (FRT) capability of distribution network-connected inverter-coupled DGs (Chapter 3). Fault-Ride-Through (FRT) capabilities are looked at because they define



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the smoothness of mode change between grid-connected and islanded operation as well as the contribution in case of grid faults to support the stability of the network and the security of supply.

2. Performance of Inverter-coupled Distributed Generators with regard to Ancillary Services

Recently, many studies have been performed on the capability of the provision of ancillary services by distributed generators. These studies ([Campbell et al 2005], [DISPOWER 2006], [ILEX;UMIST 2004], [Jóos et al 2000], [Mutuale, Strbac 2005], [Robert et al 2005], [Robert;Belhomme 2005], [Tolbert;Yu 2006]) show different results because of different assessment approaches. The analysis of these previous studies identifies three main short-comings.

1) On the one hand, economic and technological capabilities need to be analysed separately. This separation is necessary because the economic framework is different in many countries and is expected to change in the future considerably while the technological capabilities are expected to change only due to the long-term technological progress. In other words, the technological capabilities are based on physical laws, while the economic attractiveness is based on the applied economic framework which uses assumptions, e.g. for the discount rate or future market prices, with a high degree of flexibility.
2) On the other hand, the technological capabilities need to be analysed separately for the grid coupling technology and the rest of the DG unit. This separation is necessary because the grid coupling technology is the entity which connects the DG unit to the grid and defines many of the technological capabilities of the DG unit. This coupling device can be different for the same DG unit. For instance, a biomass plant might be preferred to be equipped with an inverter as a substitute of a synchronous generator because of its additional capabilities for the improvement of voltage quality. This high flexibility for component combinations needs to be taken into account.
3) A third short-coming arises from the number of ancillary services and DER units which is looked at. Many studies only analyse a couple of ancillary services or a couple of DER units without giving the whole picture.

As a result from these identified shortcomings a need was seen to analyse the technological capabilities systematically and comprehensively for a large range of DER units and a large range of ancillary services. This analysis has been performed in [Braun et al. 2006] and [Braun 2007a].

In the study at hand this analysis is updated and focused on inverter-coupled DGs with regard to Microgrids. This assessment follows the approach presented in Figure 2-1 schematically. On the one hand it separates technological capabilities based on physical laws from the economic attractiveness which depends on different framework conditions. On the other hand, the technological capabilities are analysed with an approach of looking firstly at the grid coupling technology of the DER unit, and secondly looking at the whole DER unit.

Technological capability in this report means, what the technology is principally capable to do. This does not mean that this “feature” is commercially available on the market. Perhaps it even has not been implemented because there are few incentives for DER to provide ancillary services. The economic framework is not analysed here but it should be developed in a way to utilise the technological capabilities in a way of maximal economic welfare.

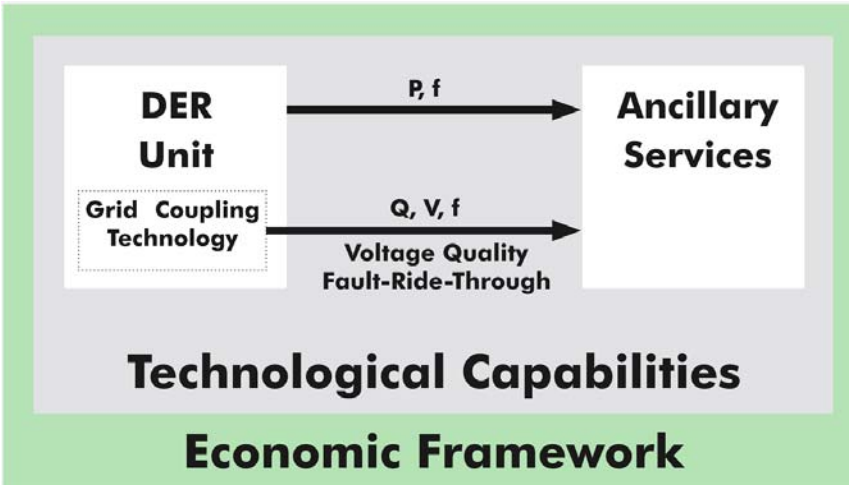


Figure 2-1: Applied Assessment Approach [Braun 2007a]

An analysis of the capabilities of inverter-coupled DGs to provide ancillary services is performed in Chapter 2. A short characterisation of these ancillary services is given in Chapter 2.1 with the focus of understanding the requirements for the provision of ancillary services by DGs. Based on these requirements it becomes possible to analyse the capabilities of inverter-coupled DGs from a technological perspective.
Firstly, the technological capabilities of inverters are analysed in Chapter 2.2. Secondly, the technological capabilities of the whole inverter-coupled DER unit are presented in Chapter 2.3.

2.1. Characterisation of Ancillary Services

With an increased penetration of DER at the distribution network combined with the objective of a more reliable and cost-efficient network operation, it becomes supportive to apply new ancillary services in the future operation of the distribution and transmission network by Distribution Network Operators (DNOs) and Transmission Network Operators (TNOs). Consequently the definition of present ancillary services according to Eurelectric has to be modified:
"Ancillary Services are those services provided by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser. These services are required to ensure that the System Operator meets its responsibilities in relation to the safe, secure and reliable operation of the interconnected power system. The services include both mandatory services and services subject to competition." [Eurelectric 2000]
A definition of future ancillary services should include the DNO and his infrastructure in addition to the TNO. Moreover, beside of generation, also consumption and storage equipment can provide ancillary services. The definition's enhancements is particular important in case of Microgrid control concepts where ancillary services are primarily provided to the DNO and only DER units are able to provide them during islanded operation.

The following types of ancillary services are analysed in Chapter 2.1. They are classified according to the operation modes of Microgrids (normal operation and emergency operation / grid-connected operation and islanded operation).

- Grid-Connected Operation:
  - Frequency Control Support (to TNO)
  - Voltage Control Support
  - Congestion Management
  - Reduction of Grid Losses
- Islanded Operation:
  - Black Start
  - Grid-Forming Operation:
    - Frequency Control
    - Voltage Control
  - Grid-Tied Operation:
    - Frequency Control Support
    - Voltage Control Support
    - Congestion Management
    - Reduction of Grid Losses
    - Improvement of Voltage Quality (reduction of flicker, compensation of harmonics)

All these ancillary services are important for the operation of a Microgrid. One additional service is studied in Chapter 3: Fault-Ride-Through Capability. This service increases the power quality by improving the smoothness of mode change between grid-connected and islanded operation as well as the stability of the network and the security of supply in case of grid faults.

Different types of control architectures are studied in other Tasks of the project. Here, it is sufficient to concentrate on the basic functionalities.

An important distinction is based on the way of the provision of the service:

- fast, local and generally automatic control within seconds (e.g. primary voltage or primary frequency control), or
- remote, centralised and coordinated control within minutes (e.g. secondary/tertiary voltage control or secondary/tertiary frequency control).

These two ways include different time horizons (speed of service provision) and different spatial perspectives (local or remote).

Before characterizing the different ancillary services a discussion is necessary on the interdependencies of electrical variables.

2.1.1. Basic Control Capabilities

One dependency has to be discussed with regard to the Microgrid's characteristic of operating partly grid-connected and partly islanded. It is the interdependency between the electrical variables active power P, reactive power Q and voltage U. An understanding is necessary if an indirect control of voltage (voltage control support) should be achieved by active and reactive power control. With the following basic equations the interdependencies are analysed and the results are presented in Figure 2-2.

Reference voltage source vector: $\underline{u} = Ue^{j\omega_N t}$

Second voltage source vector: $\underline{u}_2 = U_2 e^{j\omega_N t} e^{-j\delta}$

Network impedance vector: $\underline{z} = Ze^{j\varphi_N} = R + jX$ (2-1)

Current vector over impedance: $\underline{i} = \frac{\underline{u} - \underline{u}_2}{\underline{z}}$

Apparent power vector: $\underline{S} = \frac{1}{2}\underline{u} \cdot \underline{i}^*$

Active power vector: $\underline{P} = \Re(\underline{S})$ (2-2)

Reactive power vector: $\underline{Q} = \Im(\underline{S})$

Figure 2-2 shows the analysed equivalent circuit with two voltage sources $\underline{u}$ and $\underline{u}_2$ which are connected via the network impedance $\underline{z}$ with the impedance angle φ_N (or the resistance/reactance = R/X-ratio = 1/atan(φ_N)). The active and reactive power transfer capability is analysed with regard to the voltage difference dU (corresponding to voltage control) and the voltage angle δ (delta) resulting from the integral over the frequency deviation of the voltage source on the right hand side (corresponding to frequency control):

$$\delta = \int_t \Delta f \; dt \tag{2-3}$$

See also [Engler 2005] and [Jahn 2007] for similar analyses.

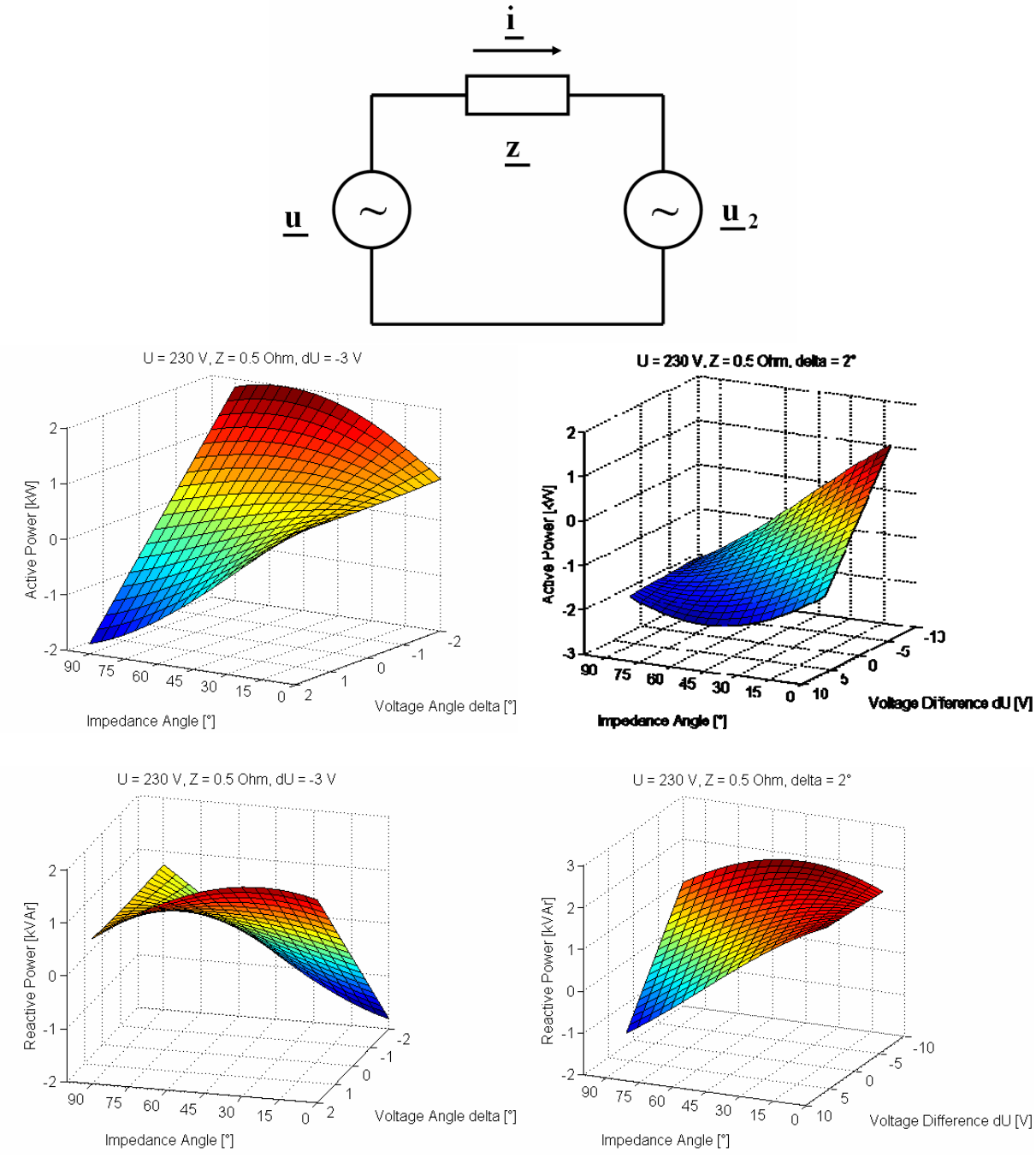


Figure 2-2: Interdependency of P, Q, U, δ, φ_N (MATLAB calculations)

For all four pictures the voltage magnitude of $\underline{u}$ is fixed to U = 230 V and the absolute value of the network impedance is fixed to Z = 0.5 Ω. The time t is set to zero as the steady-state is analysed.

On the left hand side active and reactive power are presented in dependency of the voltage angle delta at fixed voltage difference dU = -3 V. It can be seen that at $\varphi_N = 0°$ (pure resistive coupling) nearly no active power transfer is possible but reactive power transfer. This dependency is reversed at $\varphi_N = 90°$ (pure reactive coupling) as the transfer is limited to active power.

On the right hand side active and reactive power are presented in dependency of the voltage difference dU at fixed voltage angle $\delta = 2°$. It can be seen that at $\varphi_N = 0°$ (pure resistive coupling) nearly no reactive power transfer is possible but active power transfer. This dependency is reversed at $\varphi_N = 90°$ (pure reactive coupling) as the control is limited to reactive power. Compared to the right hand side, the dependencies are reversed.

Summarizing these interdependencies the following approximations of functional dependencies can be stated for different network levels and their resistive/reactive-coupling characteristic:

- Low Voltage (LV) network ($\varphi_N \rightarrow 0°$, R/X > 1):
  - P(U)
  - Q(δ)
- Medium Voltage (MV) network ($\varphi_N \approx 45°$, R/X ≈ 1):
  - P(U,δ)
  - Q(U,δ)
- High Voltage (HV) network ($\varphi_N \rightarrow 90°$, R/X << 1):
  - P(δ)
  - Q(U)

More detailed data of φ_N and X/R gives Table 2-1 for Germany, Russia and Brazil. In addition, the initial short-circuit power $S''_{SC,I}$ is provided which describes together with φ_N very well the characteristics of the superordinate network (including the internal network configuration, e.g. radial or meshed). The table shows the maximum values of φ_N which are to be found near the substation to the superordinate network. These high values of X/R result from the transformer in the substation with its inductive characteristic. The minimum values describe the network's characteristics far from the substation to the superordinate network, e.g. at the end of a feeder. Due to the variety of network configurations Table 2-1 shows examples of the minimum network impedance angles for three countries. While at high AC voltage levels overhead lines (highly inductive) reduce the network angle only marginally, at lower voltage levels with cables (highly resistive) the phase angle is reduced significantly.
Table 2-2 provides an overview of typical line data. At LV the diameter is normally below 150 mm² resulting in R/X > 1 and at MV, the diameter is normally around 150 mm² resulting in R/X ≈ 1. AC overhead lines in HV and EHV have a R/X << 1 and can therefore considered as inductive.

Rated Voltage [kV]	Initial Short-Circuit Power $S''_{SC,i}$ [GVA]	Network Impedance Angle φ_N [°]	X/R Ratio
750 – 765	24 – 84	87-88	19.1 – 28.6
525	12 – 60	87	19.1
500	6 – 50	85-87	11.4 – 19.1
420 – 440	4 – 40	86	14.3
300 – 362	2.3 – 35	85-86	11.4 – 14.3
220/230 – 245	1.7 – 20	80-86	5.7 – 19.1
138 – 170	0.9 – 10	72-86	3.1 – 14.3
110	0.5 – 6	79-86	5.1 – 14.3
69	0.3 – 3	62-86	1.9 – 14.3
30 – 35	0.2 – 1.0	82-86	7.1 – 14.3
20 – 23	0.03 – 0.5	26-86	0.49 – 14.3
10 – 15	0.01 – 0.2	39-85	0.81 – 11.4
0.4	0.002 – 0.1	37-75	0.75 – 3.7

Table 2-1: Average values of initial short-circuit power, network impedance angle and X/R ratio for Germany, Russia and Brazil [Valov at al 2007]

Voltage Level	Material	Diameter [mm²]	R' [Ohm/km]	X' [Ohm/km]	X/R	R/X	φ_N [°]	Type
Conductors [Hosemann 1988]:								
750 kV	Al/St	805/102	0.009	0.272	30.2	0.0	88.1	
110 kV	Al/St	435/55	0.033	0.266	8.1	0.1	83.0	
Cables [DIgSILENT 2007]:								
	Al	50	0.641	0.107	0.2	6.0	9.5	NA2XSY 3x50sm 6/10kV
10 - 30 kV	Cu	150	0.124	0.104	0.8	1.2	39.9	N2XSY 3x150rm 12/20kV
	Cu	500	0.034	0.166	4.5	0.2	77.6	N2XS2Y 1x500RM 18/30kV ir
	Al	50	0.641	0.072	0.1	8.9	6.4	NA2XY 3x50sm 0.6/1kV
1 kV	Al	150	0.206	0.069	0.3	3.0	18.6	NA2XY 3x150sm 0.6/1kV
	Cu	300	0.060	0.069	1.2	0.9	49.0	N2XY 3x300sm 0.6/1kV

Table 2-2: Typical line data

The voltage control (support) capability is analysed more deeply. It is assumed that a generator is feeding-in a current $\underline{i}$ with different generator phase angles φ_G. The result on the generator-side voltage $\underline{u}_G$ is displayed in Figure 2-3 according to the following (steady-state) equations by the voltage ratio U_G/U.

Reference voltage:	$\underline{u}(t=0) = U$	
Generator current vector:	$\underline{i}_G(t=0) = I_G e^{j\varphi_G}$	
Impedance vector:	$\underline{z} = Ze^{j\varphi_N} = R + jX$	
Generator voltage vector	$\underline{u}_G = \underline{u} - \underline{u}_d$	(2-4)
Impedance voltage drop vector:	$\underline{u}_d = \underline{z} \cdot \underline{i}_G$	
Ratio generator to reference voltage:	$\frac{U_G}{U} = \frac{\left\lvert U - Ze^{j\varphi_N} \cdot I_G e^{j\varphi_G} \right\rvert}{U}$	

Figure 2-3 shows that at a network phase angle of $\varphi_N = 0°$ (pure resistive coupling) the voltage is increased by current feed-in (power generation). The maximum result on the voltage occurs at purely active power generation while at purely reactive power generation no influence on the voltage exists. On the other hand, at a network phase angle of $\varphi_N = 90°$ (pure resistive coupling) the voltage is

- increased by capacitive reactive power supply,
- decreased by inductive reactive power supply, and
- not influenced by active power generation.

Summarizing these dependencies the following approximations can be stated for different network levels and their resistive/reactive-coupling characteristic:

- LV network ($\varphi_N \rightarrow 0°$, R/X > 1): Voltage control (support) by P (& Q)
- MV network ($0 << \varphi_N << 90°$, R/X ≈ 1): Voltage control (support) by P & Q
- HV network ($\varphi_N \rightarrow 90°$, R/X << 1): Voltage control (support) by Q

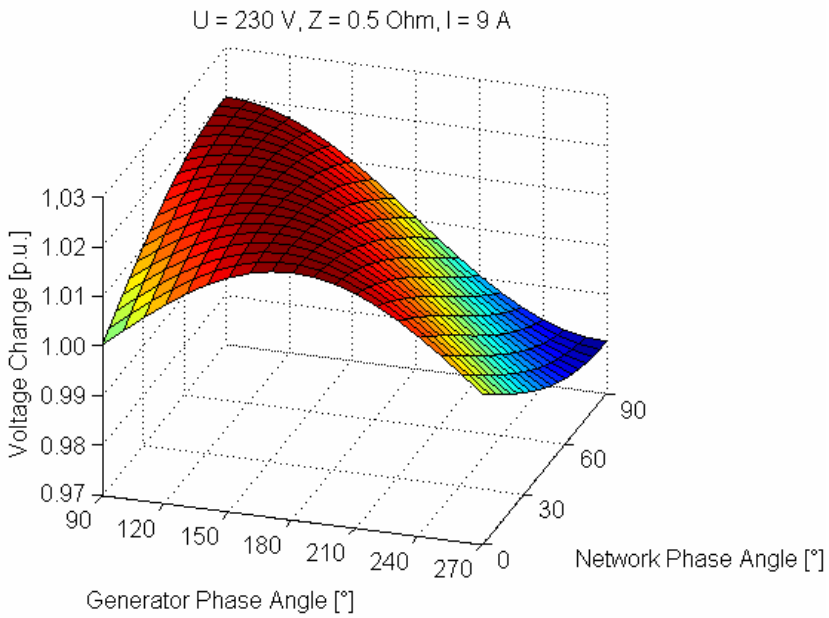


Figure 2-3: Voltage Control (Support) by generator phase angle φ_G at different network phase angles φ_N (MATLAB calculations)

In case of a Microgrid's operation the active distribution network control has to face the reduced influence of the reactive power on the voltage and the increased influence of the active power. In other words, the reactive power transfer capability by voltage differences of low voltage networks is far less than the reactive power transfer capability of high voltage networks (cf. Figure 2-2).

The *basic* control capabilities which are necessary for the provision of these ancillary services (exclusively the improvement of voltage quality) are active power, reactive power, direct voltage and direct frequency control. Table 2-3 shows their allocation to the ancillary services they can be or have to be applied for.

- Active power control is necessary for frequency control support. This not only the case for the interconnected grid but also for frequency control in islanded operation of distribution grids as shown in [Engler 2005]. The speed control of synchronous generators is linked with the active power and the dependency can be implemented in the inverter control as well.
- Voltage control support, congestion management and the optimisation of grid losses mostly depend on the reactive power control. However, also active power control has an impact and can be used (especially on the distribution grid level) but generally as the second-best option because of its mostly higher economic value compared to reactive power.
- Active and reactive power control is necessary for Grid-Forming (Islanded Operation) and Black Start. In addition it is necessary to define directly the frequency itself (e.g. speed control of synchronous generators or definition by inverter control) and the voltage. Only with all four basic control capabilities it is possible to form a grid by defining the voltage form.

Ancillary Services	*Active Power* *P*	*Reactive Power* *Q*	*Direct Voltage* *V*	*Direct Frequency* *f*
Frequency Control Support	X			
Voltage Control Support, Congestion Management, Optimisation of Grid Losses	x	X		
Grid-Forming / Black Start	X	X	X	X

Table 2-3: Basic Control Capabilities (P,Q,V,f) for Ancillary Services
(X: required; x: also possible)

These fundamental control necessities for most of the ancillary services demand for an optimisation process by the network's operator which takes into account interdependencies and treats the trade-offs according to the objective followed.

On the one hand, a change of reactive power would have an impact on the voltage profile, congestions and grid losses. The objective could be to minimise reactive power flows. This leads to less congestions and less grid losses, but also to a restriction of the voltage control capabilities which have to stay within the voltage limits.

On the other hand, a change of the active power would have an impact on the frequency, voltage profile, congestions and grid losses. If only frequency and voltage control are considered a scenario demonstrates the difficulties of defining the correct control strategy. If the frequency is at its minimum limit the active power output should be increased resulting further increase of the voltage profile over its maximum limit. This exemplary trade-off has to be taken into account in the applied control concept.
Moreover, two approaches can be applied for secure network operation: ancillary services and network reinforcement. The optimal cost-efficient network operation is achieved when the costs for network reinforcement together with the costs for the provision of ancillary services are minimal.

The following sub-chapters characterize the different ancillary services.

2.1.2. Frequency Control / Frequency Control Support

Nearly each country has its own definitions and specifications of active power reserve services [Rebours;Kirschen 2005a]. In this document, the definitions of UCTE (cf. Figure 2-4) are used [UCTE 2004]:

"The objective of primary control is to maintain a balance between generation and consumption within the synchronous area, using turbine speed or turbine governors. By the joint action of all interconnected undertakings, primary control aims at the operational reliability of the power system of the synchronous area and stabilises the system frequency at a stationary value after a disturbance or incident in the time-frame of seconds, but without restoring the reference values of system frequency and power exchanges."

"Secondary control maintains a balance between generation and consumption within each control area as well as the system frequency within the synchronous area, taking into account the control program, without impairing the primary control that is operated in the

synchronous area in parallel but by a margin of seconds. Secondary control makes use of a centralised automatic generation control, modifying the active power set points in the time-frame of seconds to typically 15 minutes. Secondary control is based on secondary control reserves that are under automatic control. Adequate secondary control depends on generation resources made available by generation companies to the TSOs."

"Tertiary control uses tertiary reserve {15 minute reserve} that is usually activated manually by the TSOs after activation of secondary control to free up the secondary reserves. Tertiary control is typically operated in the responsibility of the TSO."

Other often used terms are

- "Frequency Response" instead of primary frequency control and
- "Spinning Reserve" instead of secondary and tertiary frequency control.

The frequency is managed by a combination of continuous and occasional response services. Continuous response is provided by generation equipped with appropriate governing systems which control their outputs to neutralise the frequency fluctuations which arise from relatively modest changes in demand and generation. The objective of occasional response is to reduce significant and abnormal frequency excursions, which are caused by sudden mismatches in the generation/demand balance.

The commonly used term "frequency control" subsumes different control approaches. Prime mover speed control is fundamental for all synchronous generators in the power supply system because the turbine speed is proportionally correlated with the electrical grid frequency. Direct frequency control is possible with this speed control. Imagine a network at outage. There has to be at least one generator which controls the frequency directly while black starting the network. If the electrical frequency is established in the network (can be assumed to be equal everywhere) the sketched frequency control support (divided into primary, secondary and tertiary frequency control) is applicable. Instead of the commonly used term "frequency control" it is called "frequency control support" in this report because it does not directly control the frequency (which would be done by the speed controller) but indirectly by active power control. This distinction is necessary particularly in case of generators based on power electronics.

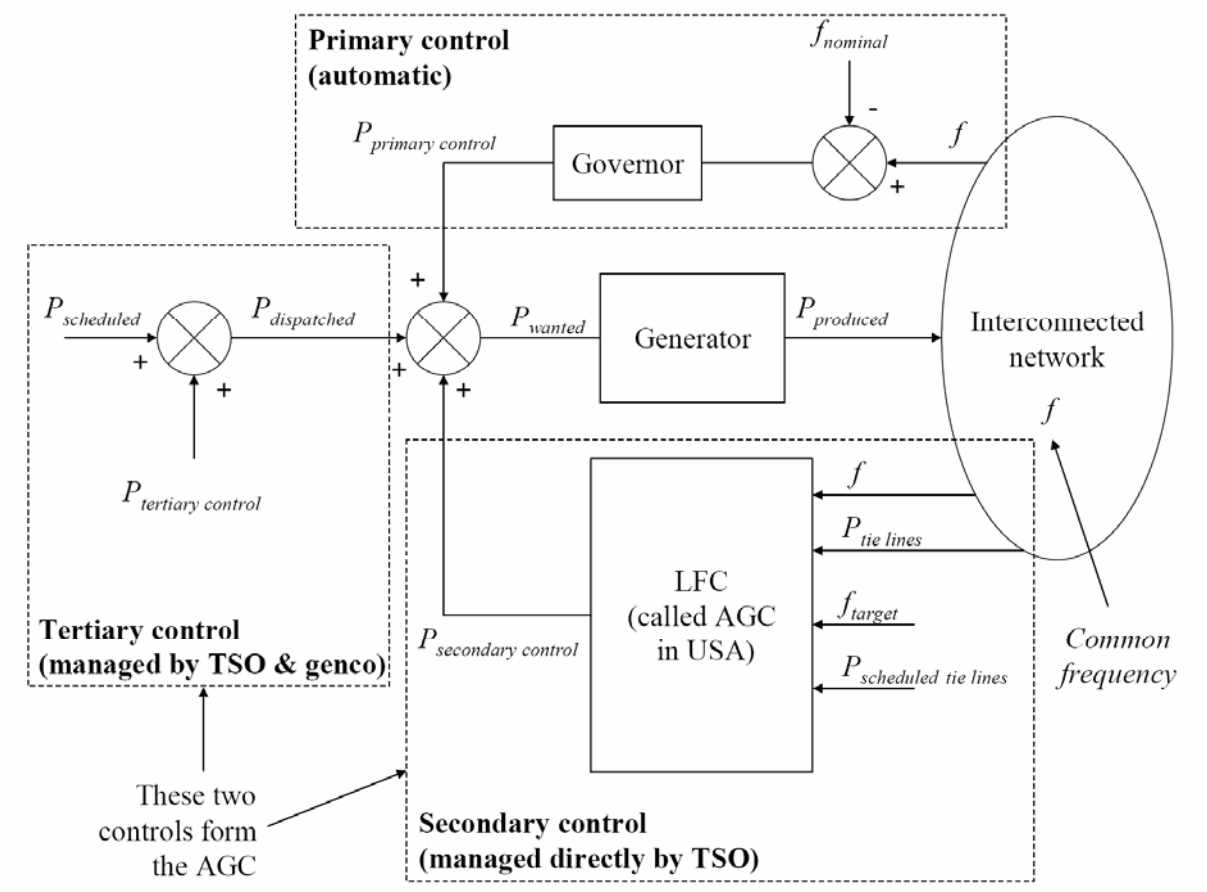


Figure 2-4: Organisation of frequency control (LFC = Load-Frequency Control, AGC = Automation Generation Control) [Rebours;Kirschen 2005b]

2.1.2.1. Direct Frequency Control

Direct Frequency Control is a fundamental ancillary service for electrifying an electrical network. While the prime mover speed controller is a basic component of all synchronous generators inverter-coupled DER units have to be controlled specifically to emulate the speed control as they are so called “static” generators. The direct frequency control is necessary in case of black start or islanded operation with grid-forming inverter-coupled DER units. This is different to the grid-tied operation where frequency control support can be provided by active power control with a hierarchically control structure (primary, secondary, tertiary).

2.1.2.2. Primary Frequency Control Support or Frequency Response

Primary frequency control (support) is a decentralised automatic active power control. Governors change the active power output of a generator depending on the droop with the system frequency in order to balance demand and generation. Figure 2-5 shows that the active power is linearly reduced from the rated active power Pn to P = Pn – ΔP if the

frequency deviates from the rated frequency fn to f = fn + Δf. This is called high frequency response as the frequency is higher than the rated frequency. Analogously, the active power is linearly increased from the rated active power Pn to P = Pn + ΔP if the frequency deviates from the rated frequency fn to f = fn - Δf. This is called low frequency response as the frequency is lower than the rated frequency.

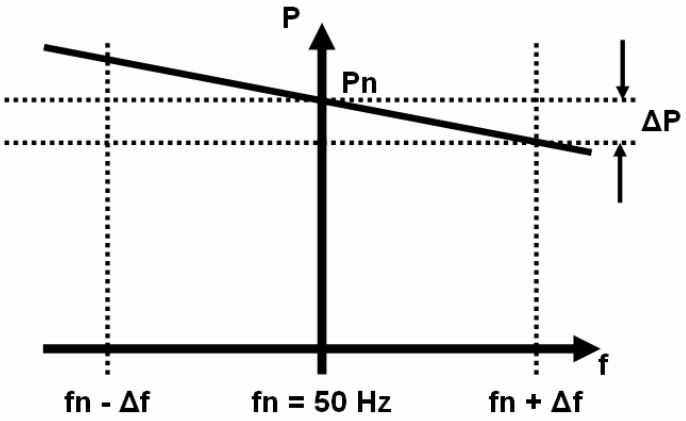


Figure 2-5: Active power frequency droop

Due to the droop of the generators the systems frequency stabilises on a new level. The reaction time has to be within less than 30 seconds.

An essential feature of low frequency response services from generators is the requirement for part-loaded operation, which enables an increase of the generator output. In order to provide low frequency services, DGs have to operate in frequency sensitive mode and run part-loaded. Similarly, in addition to such low frequency response services, DG could provide high frequency response services. These high frequency response services are easier to provide by DGs because a reduction of power generation is easier than an increase.

While for DGs it is easier to reduce the production, for controllable loads it is easier to reduce the consumption. Consequently, DGs might be preferred for high frequency response while loads might be preferred for low frequency response. In general, storage does not have a preferred contribution, low as well as high frequency response are possible. Only in case of storage limits one direction could be preferred: if the storage is at its lower limit it is not desired to inject power into the grid and if the storage is at its upper limit it is not desired to extract power from the grid.

Frequency response services are currently provided by a relatively small number of generators. Opportunities for DGs are often constrained by infrastructural requirements, their reliability and the size of generators [VDN 2007]. The frequency is controlled constantly if the frequency deviation exceeds +/- 20 mHz until the deviation is fully compensated by secondary frequency control [UCTE 2004].

2.1.2.3. Secondary and Tertiary Frequency Control Support / Spinning Reserve

“The spinning reserve is the unused capacity which can be activated on decision of the system operator and which is provided by devices which are synchronized to the network and able to affect the active power” [Rebours;Kirschen 2005b]. Spinning reserve corresponds to the UCTE secondary (automatic and central) and synchronised tertiary control reserves (manual and central) as these reserves are deployed on the instruction of the TNO. The primary control reserve, which is not controlled by the TNO, has to be

excluded from the spinning reserve. A consumer can provide spinning reserve, if it agrees to change its consumption (e.g. pump loads) upon request by the TNO.

Typically, spinning reserve is manually initiated following TNO instructions and involves lead times of several minutes. A consequence of these simplified requirements is a reduction in the sophistication of the associated control infrastructure making this service more attractive to smaller players.

Spinning reserve is sourced from both synchronised, part-loaded providers as well as standing, non-synchronised providers which are capable of starting, synchronising and providing the TNO's instructed level of output within several minutes. The allocation of reserve between synchronised and standing providers is a trade-off between the cost of efficiency losses of part-loaded synchronised plants (plant with relatively low marginal costs but running at all times) and the cost of operating a less efficient standing plant (plant with relatively high marginal cost but running only occasionally).

2.1.3. Voltage Control Support and Direct Voltage Control

In any AC power system the voltage and current are, normally, not in phase. Hence, reactive power will flow. Reactive power is considered as being absorbed by inductive components (e.g. transformers, overhead lines, induction motors) and generated by capacitive components (e.g. over-excited synchronous machines and capacitors).

In a high voltage-grid whose impedance exceeds its resistance, reactive power transfer depends mainly on voltage magnitudes (cf. Chapter 2.1.1 and Figure 2-2). It is transmitted from the side with higher voltage magnitude to the side with lower voltage magnitude. Reactive power cannot be transmitted over long distances since it would require a large voltage gradient to do so. Therefore, voltage control has to be locally distributed.

The reactive power flow can be compensated with sources and sinks of reactive power, e.g. synchronous generators, shunt capacitors, shunt reactors, synchronous condensors, and static var compensators (SVCs), as well as line reactance compensators such as series capacitors. This compensation of reactive power reduces the voltage drop. Additionally, the voltage drop caused by the active power flow can be compensated by supplying a negative reactive power flow (by varying the systems reactance) because a capacitive current causes a voltage rise while an inductive current causes a voltage drop (cf. Chapter 2.1.1 and Figure 2-3). Consequently, a control in both directions is possible. [Kundur 1994]

Voltage control is performed by two basic principles:

- Direct voltage setting by generation units and tap-changing transformers (voltage control)
- Indirect voltage control (support) by changing the power extraction/injection (cf. Chapter 2.1.1 and Figure 2-3)

Direct voltage setting is based on the unidirectional power flow concept: A source (synchronous generator) feeds power into a grid and defines a starting value of the voltage with its automatic voltage regulator. This voltage is reduced due to the voltage drop over grid impedances until the power flow reaches the sink (loads). In between, voltage levels might

be changed via transformers. These transformers (regarded as sinks for the upper voltage level and regarded as sources for the lower voltage level) can change their winding ratio by tap changers to set a new starting voltage value for the lower voltage grid.

Within the grid, esp. in case of bidirectional power flow, voltage corrections have to be performed to stay within the permitted limitations. Due to power extraction/injection, the voltage can be changed indirectly (see Chapter 2.1.1 and Figure 2-3), as this changes the power flows through the grid impedances. Indirect voltage control is presently based on reactive power control and applied in transmission grids. In transmission grids with their inductive lines, the voltage is mainly dependant on the reactive power. This situation changes for distribution grids with considerable resistances of the lines resulting in a significant influence of active power flows.

Historically, voltage regulation on passively managed distribution networks has been achieved through the robust specification of primary network infrastructure, on-line transformer tap changing equipment and fixed tap distribution transformers. Maintaining voltages within tolerances represent an absolute technical obligation for DNOs. The implications to a DNO of voltages being outside statutory limits are severe because damage to customer equipment can occur and the security of supply can be endangered. If voltages are found to be outside statutory limits (e.g. EN 50160), DNOs must remedy such situations immediately or interrupt supplies to customers.

The increased penetrations of DG could give rise to wider ranges of power flows (including reversals) and hence wider voltage variations. Such variations could be outside the operating ranges of existing voltage regulating equipment, thus requiring DNOs to evaluate revised more active voltage control arrangements which are studied in other Tasks of the MoreMicrogrids project.

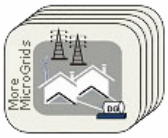
In an era of significantly higher levels of DG, there will be increased scope for distribution network voltages to be controlled through the regulation of generator outputs. Such approaches would be similar to the technique adopted for voltage control on transmission networks, although DNOs would probably need to regulate both active and reactive power flows in order to achieve the desired voltage changes.

One possible concern regarding the use of generation based solutions for distribution network voltage control relates to the availability and reliability of generation equipment. Those generators with the highest availabilities, the broadest and most flexible output ranges for active and reactive power will represent the most attractive service providers of voltage management services to DNOs in the future. Voltage violations mostly occur for short periods, e.g. at times of peak demand. Consequently, also DGs with lower control availabilities are of interest.

The opportunities for DG to provide voltage support in distribution networks could be enhanced considerably if the European Voltage Standard (EN 50160), describing voltage limits in statistical terms, is used to assess DNO compliance with statutory obligations on voltage limits. It would not be necessary to work on the basis of a zero tolerance for voltage excursions as it is often done at present.

Three different levels of voltage control exist presently:

- Primary voltage control
- Secondary voltage control



- Tertiary voltage control

Primary Voltage Control maintains the voltage at the PCC of the generator close to a voltage reference given by the TNO. It is the voltage regulator of the different generators which have a fast response to keep the voltage at the generator equal to the setting point. The system operator fixes the voltage setting points of the different generators in order to guarantee an adequate operating point regarding the (n-1) criterion, the maximal reactive power which is possible to generate by each generator, the voltage drop in the transmission lines and finally the voltage profile at the transmission buses. The dynamic reaction of the primary voltage control is about some seconds to one minute. [CRISP 2004]

Secondary Voltage Control consists on the measurements of the voltage magnitude in some critical buses of the system. These buses are known by the operator as the result of its experience in the control of the system. If the voltages at these buses are out of range, the operator is going to change the settings points of the voltage regulators (generators) in order to recover a voltage profile in the normalised interval. The time response of the voltage secondary control goes up to one minute and less than several minutes. [CRISP 2004]

Tertiary Voltage Control is used by the operator to optimise the system voltage profile and to provide reference values of the secondary voltage control. Normally, the tertiary control operates in a 15 minutes cycle. [CRISP 2004]

2.1.4. Congestion Management

The security of supply is in danger if the current limitations of grid components are exceeded a certain time period. The congestion management tries to find these critical components in the observed grid and looks for a reconfiguration to prevent the outage of these critical components. This reconfiguration, which increases the security of supply to an acceptable level, is achieved by

- a network reinforcement,
- a reconfiguration of the network structure, or
- a re-dispatching of the power flows which cause the critical currents.

Controllable DER units have the capabilities to influence the power flows which increase the flexibility of the congestion management significantly in comparison to the network's situation without controllable DER. This ancillary service is strongly interrelated with the reduction of grid losses and voltage control support. In a first approach the reactive power would be compensated as good as possible (due to its lower economic value) and in a second step the active power would be controlled aiming at solving congestions.

2.1.5. Reduction of Grid Losses

The main objective of the optimisation/minimisation of grid losses is to reduce the costs of the power transport and distribution. According to IEC 287 it is possible to calculate these line losses. These extensive equations to the line characteristics can be simplified to the following equation which considers only the losses which can be influenced due to a reduction of the power flow over the line. The line losses for a length unit P'_L are calculated by:

$$P'_L = 3 \cdot R' \cdot I^2 = 3 \cdot R' \cdot \left(\frac{S}{\sqrt{3}U} \right)^2 = \frac{R' \cdot (P^2 + Q^2)}{U^2} \qquad (2\text{-}5)$$

The equation comprises a resistance per length unit R' which is defined by the line's characteristics and the current I which flows over this resistance. Finally, this current is expressed by the active power flow P and the reactive power flow Q over this line element of one length unit. The presented equation shows that the line losses are basically dependent on the:

- resistance of the line,
- length of the line,
- active power flow over the line,
- reactive power flow over the line, and
- the voltage level of the line.

While the losses due to the resistance, the length and the voltage level can only be optimised during the network planning process, the losses due to active and reactive power flows can be optimised during the operation by power dispatch strategies.

The optimisation of grid losses is of lower priority in comparison to the other ancillary services because its aim is only an economic improvement of normal operation while the frequency, voltage and voltage quality have to stay within their limits, congestions need to be avoided, and security of supply has to be maximised by islanded operation and a fast network restoration in case of a mains grid blackout.

DGs provide fundamental characteristics to reduce this power flow losses because they can supply the distributed loads locally due to their distributed characteristics. This local production reduces the present power flow from central generation in the order of the local power consumption. [Griffin et alt 2000] present an approach for an optimal DG placement. Besides of this passive reduction of grid losses, an increase of grid losses might occur if the local production exceeds the local consumption and opposite power flows cause additional line losses in the grid.

2.1.6. Black Start / Network restoration

Network restoration (Black Start) is the procedure for recovery from total or partial shutdown of electrical supplies in a network area (e.g. a Microgrid). After Black Start the network area is operated in islanded mode before it might be synchronised with other network areas to operate interconnected. The Black Start procedure requires a supervisor which coordinates the starting of generators and the connection of loads in a stable procedure.

[Pham et al 2005] and [Pham et al 2006] present a restoration procedure with the inclusion of a large scale of DG. The "deep build - together" strategy is proposed to simultaneously consider this rebuilding by transmission and distribution networks, thereby, to serve the maximum of customers in a minimum of time. The benefit in comparison to the present approach is a reduction of time for the restoration process by inclusion of DG. A network restoration with Black Start generators occurs rarely in the UCTE network. With the application of the Microgrid concept, it might occur even more rarely because the areas of impact are minimized. In this situation, the area which is faced to a fault can be isolated narrowly surrounded by Microgrids. After fault-clearing, these Microgrids can then restore the isolated area. The Microgrid concept provides an upgrade of Black Start procedures and a substantial increased security of supply for network customers.

Black Start capability is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from the network. Many power stations need an electrical supply to start up. To be able to Black Start, such a station must have some form of independent auxiliary supply with sufficient capacity to supply the unit auxiliaries while a main generator is prepared for operation. This additional power source is usually provided by a smaller peripheral Black Start generating plant, which is started from a battery or other energy storage device. Once operational, the power plant can then be used to energise part of its local network, providing supplies for other plants within the area to enable them to start-up. Two ancillary services are of particular importance for a Black Start: direct frequency control and direct voltage control. The Black Start works only if the unit is able to define the voltage form by its magnitude and its frequency and only if it has the active and reactive power capacity to provide the required energy for energizing the network. In other words: Black Start comprises grid-forming (Islanded Operation) as well.

At present, the penetration of DER units which is capable to provide Black Start service is not big enough to energise the transmission network. However, they might be able to energise parts of distribution grids which can then be operated in islanded mode. With the assumption of an increasing number of such island grids in the mid-term future it will then be possible to interconnect these island grids and therewith energise an increasing share of the distribution grid. Further on, this might be enhanced to the transmission network in the long-term future with an increase of DER penetration.

2.1.7. Islanded Operation / Grid-Forming

Microgrids will by definition face the situation of islanding. In this state of the distribution network it is necessary to have DGs which are forming the network by defining the voltage form and providing the active and reactive power capacity for the direct frequency and direct voltage control. They can be supported by grid-tied DGs which synchronize to the grid's voltage and provide active and reactive power control capabilities for network operation.

A Microgrid can change to Islanded Operation after Black Start but also by disconnecting from the interconnected operation for an increased security of supply, e.g. in case of an outage of the mains grid. This state change (interconnected → islanded operation) should be able without the need for black start after disconnection. In addition to protection equipment, DGs which are overtaking the grid-forming have to be designed properly. The same holds for the resynchronization (islanded → interconnected operation). Sufficient control capacity is necessary demanding for considerable penetration of distributed generation with control capabilities.

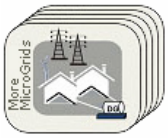
2.1.8. Improvement of Voltage Quality

The quality of service in electricity supply has three general dimensions according to [CEER 2001]:

- commercial quality (commercial relationships between a supplier and a user),
- continuity of supply, and
- voltage quality.

The commercial quality concerns the quality of relationships between a supplier and a user and can be neglected in this document as it cannot be considered as an ancillary service. However, the other two technical dimensions (continuity of supply and voltage quality) are of important interest and can be subsumed with power quality.

Continuity of supply is characterised by the number and duration of interruptions. Different indicators are used to evaluate the continuity of supply, e.g. interruption frequency [1/year], interruption duration [minutes] and unavailability of supply [minutes/year]. On the one hand, the continuity of supply might be decreased by intermittent DER units. This can happen if the power generation is lower than the demand. On the other hand, the continuity of supply might be increased because a big number of small generators is generally more reliable than a small number of big generators as the outage of one generator does not have a critical impact on the overall power generation. With the Microgrid concept and its flexible operation between interconnected and islanded operation the continuity of supply is improved for the consumers and all DER units.



Voltage quality is an important issue because of the sensitivity of end-user equipment. Industrial equipment is claimed to have become more vulnerable to power quality, while at the same time the use of electronic devices in homes and small businesses has increased the sensitivity of a greater number of users. The main parameters of voltage quality are frequency, voltage magnitude and its variation, voltage dips, temporary or transient overvoltages and harmonic distortion. The European Standard EN 50160 lists the main voltage characteristics in low and medium voltage networks, under normal operating conditions. [CEER 2001]

The impact of the improvement of voltage quality is limited to a certain network region. Presently, the voltage quality is only improved in decoupled customer networks. In Microgrids operating in islanded operation it becomes an interesting option to improve voltage quality actively as inverter-coupled DER units are able to improve the voltage quality (harmonic distortion, flicker, voltage variations) by compensating these disturbances. This has been demonstrated in the European project DGFACTS. The voltage quality can then be improved significantly within the Microgrid as an additional service to the customers

A low voltage quality might influence DG installations negatively so that protection devices disconnect the DG unit due to safety problems. In case of voltage disturbances, a disconnection would worsen the voltage quality because the voltage would decrease further due to the reduction of power injection. A fault-ride-through characteristic of DG units can have a positive impact as the voltage is supported by an injection of power by the DG which does not disconnect during the fault. This DER behaviour reduces the voltage disturbance. Moreover, it increases the continuity of supply as there is no difference of power generation before and after a fault. Without the fault-ride-through characteristic, the DER would have disconnected faced to a fault and after fault clearing the power production would have been less which might have a negative impact on the continuity of supply if the customers needs are not satisfied anymore. This FRT capability is studied in Chapter 3 of this report.

With the Microgrid concept the power quality within the Microgrid can be improved with regard to security of supply and voltage quality. This feature is a major benefit compared to static interconnected operation. Particularly inverter-coupled DER units are capable of providing the necessary characteristics. Hence, the next sub-chapter analyses the technological capabilities of inverters in general.

2.2. Technological Capabilities of Inverters

In the first step of the assessment approach (see Figure 2-1), the inverter is analysed on its control capabilities which are necessary to provide ancillary services. Because these energy converters only transform the available power input into a power output of a different characteristic, active power control is provided by the other unit's components which are analysed in more detail in Chapter 2.3. This transformation might result in a time lag of active power control. But this time lag is small enough to be neglected in the analysis here. Thus, the inverter transforms the controlled active power accordingly.

Consequently, only the capability of reactive power control, improvement of voltage quality, direct frequency control and direct voltage control can be assess with an isolated look at the inverter. Before going into the details it can be stated that in principle all inverters are capable of providing these four control features. However, these features are rarely implemented in commercial products.

2.2.1. Direct Frequency and Direct Voltage Control

Inverters can be distinguished in line-commutating inverters and self-commutating inverters. While line-commutating inverters need the grid voltage for operation, self-commutating inverters are able to operate without a grid voltage. Thus, self-commutating inverters in contrast to line-commutating inverters are capable to black start and define frequency and voltage if sufficient power capacity is available.

Depending on their DC-Link characteristics, inverters can be also classified as Current Source Inverters, Voltage Source Inverters and Z-Source inverters. An overview of these classification and their characteristics provide [Bülo et al 2007].
The most common type of inverter is the Voltage Source Inverter, which consists in DC-Link with a voltage source characteristic, normally backed up with capacitors in parallel to the DC-Link. This kind of inverter is presumably the most suitable for grid forming applications. In a simplistic manner, a VSI is nothing more than a variable voltage source coupled through an impedance to its output.

When the inverter is grid-connected and PQ-controlled, the inverter will adjust its internal voltage to be able to provide the set points of P and Q.
When the inverter is grid-forming and Vf-controlled, the inverter sees only the load impedance and thus only the voltage resulting from the voltage divider between the load and the coupling impedance. The inverter will then automatically try to retrieve the nominal voltage set point by increasing the amplitude of its internal voltage and by changing its virtual impedance. With adequate switching also the frequency can be defined.
In droop mode, the voltage set point is depending on the reactive power and the frequency set point on the active power delivery.

2.2.2. Reactive Power Control

Reactive power occurs only in AC networks due to a phase shift between voltage and current. In DC networks it is not defined. Consequently, only the grid-side inverter of DER units needs to be considered because it defines the phase angle of the current to the mains grid.

One fundamental limit is the maximum current transfer of the inverter. As long as the absolute value of the current does not exceed the limit the phase angle of the current vector can be arbitrarily controlled. It is possible to control active and reactive currents independently from each other. Figure 2-6 presents the operational areas of the current of a bidirectional inverter. The figure shows the current domain for a constant reference voltage. It displays the circle of the maximum rated current $I_{max,R}$ and the maximum overload current $I_{max,OL}$. The overload capability will not be assessed with regard to ancillary services but in Chapter 3 with regard to FRT capabilities.

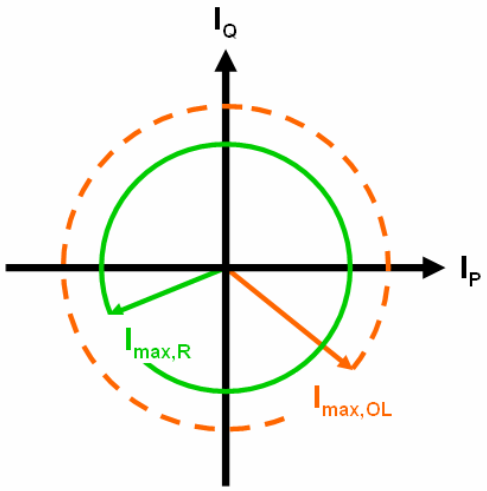


Figure 2-6: Current domains of an inverter

Analogous to the current domain, also the power domains can be looked at which are of direct interest with regard to ancillary services. Instead of a maximum current I_{max} we can then consider a maximum apparent power S_{max} with the same flexibility of active and reactive power control as for the current. The actual active power transfer P_{act} can be assumed to be the most valuable so that it limits the maximal possible reactive power supply $|Q|_{max}$ according to

$$\left|Q\right|_{\max}(t) = \sqrt{S_{\max}^2 - P_{act}^2(t)} \qquad (2\text{-}6)$$

However, also the reactive current faces limits mostly due to reasons of stability and availability. Figure 2-7 presents an example of the loading capability (power domain) of a DG unit which transfers active power and supplies reactive power. Within the

- active power generation limits
  → P_{min} and P_{max} (red),
- inductive reactive power limit
  → Q_{min} (blue, left-hand side),
- capacitive reactive power limit
  → Q_{max} (blue, right-hand side), and
- apparent power limit
  → S_{max} (green)

the reactive current of the PV inverter can be controlled arbitrarily with response times in the order of milliseconds.

While the solid blue line shows often published reactive power limits even more is possible as displayed by the dashed blue line. The availability is then dependent on the actual active power transfer so that not 100% availability can be stated but less. Also reactive power can be supplied if no active power is transferred. This is just a matter of power electronics design and the implemented control functionalities. Since reactive currents add geometrically considerable potentials for supplying reactive currents are offered even at relative high active power outputs. Some more characteristics are mentioned in the following Chapter 2.2.3.

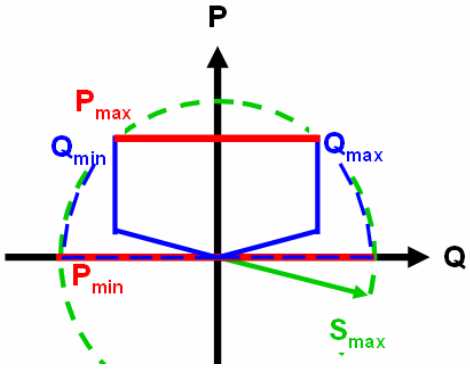


Figure 2-7: Loading capability chart (Q > 0: capacitive) of an inverter with restrictions (active power limits P_{min} and P_{max} (red), reactive power limits Q_{min} and Q_{max} (blue) and apparent power limit S_{max} (green)

Intermittent DGs (PV, WTG and Hydro) have variable active power generation $P_{act}(t)$ influencing $|Q|_{max}(t)$ (cf. equation 2-6). If the grid coupling converter's sizing matches exactly the rated active power generation there is no capacity for reactive power left if $P_{act}(t) = P_{rated}$. However, a certain oversizing of the converter leads to a certain secured reactive power control capacity. These dependencies are depicted in Figure 2-8 for a converter with the only restrictions of S_{max} and P_{max} (here P_{rated}). An oversizing of 10% for instance allows a secured reactive power control of ± 46% of P_{rated} and an oversizing of 20% even ± 66% of P_{rated} (according to equation 2-6). These values increase significantly in case of a part-loaded active power generation $P_{act} < P_{rated}$.

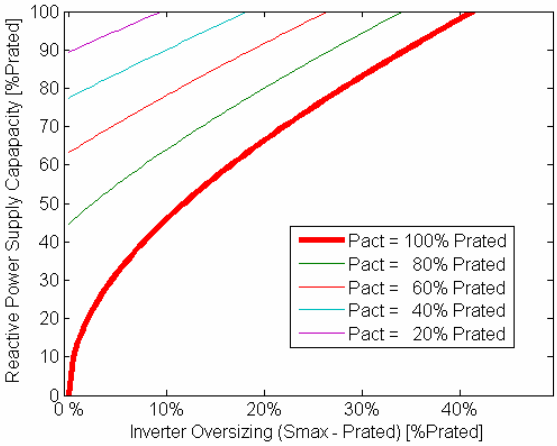


Figure 2-8: Reactive power supply capacity [%P_{rated}] depending on the converter's oversizing (S_{max} – P_{rated}) [%P_{rated}] with different P_{act} [%P_{rated}]

2.2.3. Improvement of Voltage Quality

Inverters are able to improve the voltage quality actively by compensating the harmonics and reducing flicker [Jahn 2007]. These services could be provided with little additional costs so that exploitation in Microgrids is very promising. The inverter's capabilities are predominantly limited by the maximum current of the IGBTs. So in every situation in which the device is not driving its rated apparent power there will be capabilities to inject harmonic currents.

Deformations of the grid voltage's sine curve are caused by non-linearities. Non-linear load currents cause a non-linear voltage drop across the grid impedance which is superposing the ideal sine curve. Since some frequently used and widely spread consumers such as switching power supplies cause characteristic harmonic spectra the selective compensation of characteristic harmonics can prevent additional voltage drop across the grid impedance.

Different strategies for voltage quality improvement can be used (holding also for reactive power compensation):

1. Non-selective improvement of the (entire) grid:
   Most of the grid-feeding inverters run in current-controlled mode and the only information about the current grid situation is the voltage at their terminals. Using this information the harmonic compensation depending on the grid voltage is conceivable. However, the effect of such algorithms only depends on the composition of the grid impedance and especially in low voltage grids which are predominantly resistively coupled the resulting effect is rather small.
2. Conservation of voltage quality by eliminating additional deterioration:
   By serving the inverter additional information i.e. by an external current sensor the demand of harmonic compensation of dedicated loads can be achieved. The accuracy of such compensation depends on the positioning of the current sensor. Only measuring the load current, the inverter only follows the demand. By placing the current sensor in a way that the inverter current is included the set point will become constant. In case the set point equals zero calibration of the external sensor is not essential for the total accuracy of the control.
3. Local improvement:
   By introducing a (de)coupling serial inductor into the line power quality improvements can be achieved by parallel connected devices which usually are reserved for serial devices. Depending on the sizing of the inductor the voltage in a local area can be (within certain limits) controlled independently of the grid voltage and sensitive loads can benefit of the lowly distorted voltage profile which can be achieved with inverters. The (distorted) current through the inductor tends to reduce the voltage drop across the grid impedance.

The SMA integrated DGFACTS [DGFACTS 2005] is a single-phase IGBT inverter using H-Bridge topology with an extended DC-link as energy storage (see Figure 2-9). Its nominal power is limited to 3.3 kVA. External current measurement is required for the majority of the functions (see Figure 2-10).

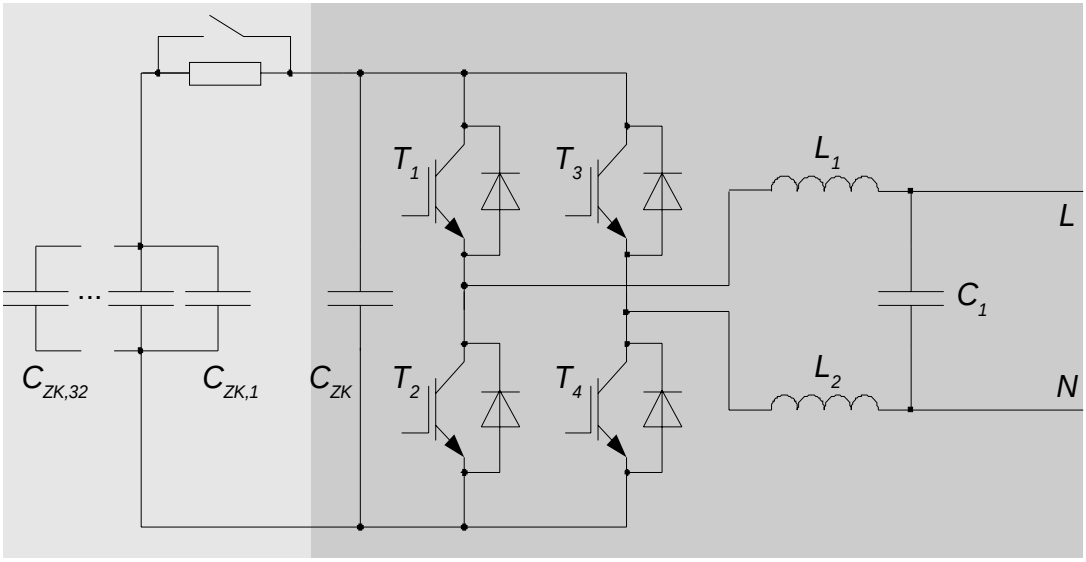


Figure 2-9: Principle circuit diagram of the SMA stand-alone prototype (light grey part: newly designed DC-link, darker grey part: original hardware basis of the SMA "Sunny Island" battery inverter) [DGFACTS 2005]

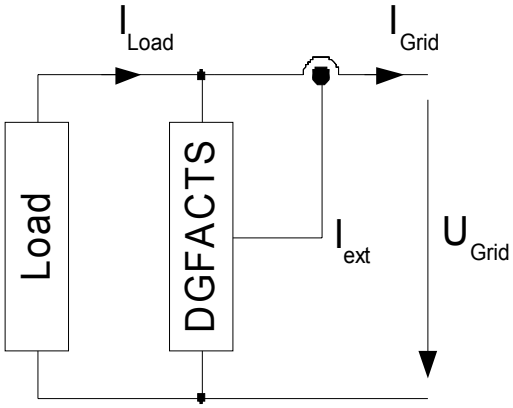


Figure 2-10: Connection of the external current sensor [DGFACTS 2005]

A large variety of functions has been developed and implemented. These comprise functions in voltage control mode with subordinate power or current control and external current measurement [Jahn 2007]:

- Reactive Power Compensation (see Chapter 2.2.2):
  In this mode the device injects reactive power according to an internally served set value. Measurements carried out on prototypes manufactured within the DGFACTS project showed that reactive power can be compensated almost totally.
- Harmonics Compensation (orders 3, 5, 7, and 9):
  The prototype is able to compensate almost entirely the harmonics 3, 5 and 7: the compensation ratio measured in laboratory is above 96%. Figure 2-11 provides a graphical illustration of the compensation achieved for the 3rd harmonic. The resulting 3rd harmonic is hardly visible.
- Line current rate limitation for flicker reduction:
  This algorithms aims at reducing flicker that is introduced by high current slopes in weak networks resulting in flicker relevant voltage variations. By lowering the slope

the flickers could be shifted to less flicker relevant frequencies. The inverter detects large current slopes of a dedicated load and injects current in a way that the slopes are smoothened.
Figure 2-12 shows that the current drawn from the grid at the connection is smoothened by injecting a current to reduce the current slope. The upper part of Figure 2-12 shows the instantaneous voltage at the equipment terminal and the instantaneous current injected by the device. The middle part shows the computed RMS voltage and current.

- Fault-Ride-Through Capability (see Chapter 3):
  The upper part of Figure 2-13 shows the instantaneous voltage at the equipment terminal and the instantaneous current injected by the device. The middle part shows the computed RMS voltage and current. The RMS computation has been done using a 1-cycle averaging window. Lastly, the lower part of the figures shows the reactive power injection, also computed with a 1-cycle averaging window.
  The prototype reacts with a delay to the voltage disturbance (about one cycle at sag initiation). Then, an increased current is injected into the grid to compensate the voltage sag.
  A FRT capability can be implemented in inverters by an appropriate protection parameter setting which delays the disconnection in case of disturbances. Additionally, the current control has to be independent from the voltage in case of a voltage collapse. The current control has to ensure a maximum current in case of a voltage collapse in order to guarantee a maximum power output.
  In case of a voltage dip, the power generation on the grid side has to be reduced to stay within the maximum current limit of the inverter. This power reduction has to be performed on the “prime mover” side as well to maintain power balance. In case of an electrical DC prime mover (PV or fuel cell), this can be done by reducing the DC voltage to move the operation point from the maximum power point in the voltage-current curve to a less efficient point. In case of mechanical prime movers, resistances have to be installed in the electrical system at the prime mover side of the inverter in order to reduce the power flow to the inverter. Comparing these two types of prime mover systems, the DC connection shows the capability of promptly changing the DC voltage while the switching of the resistances needs some more time.

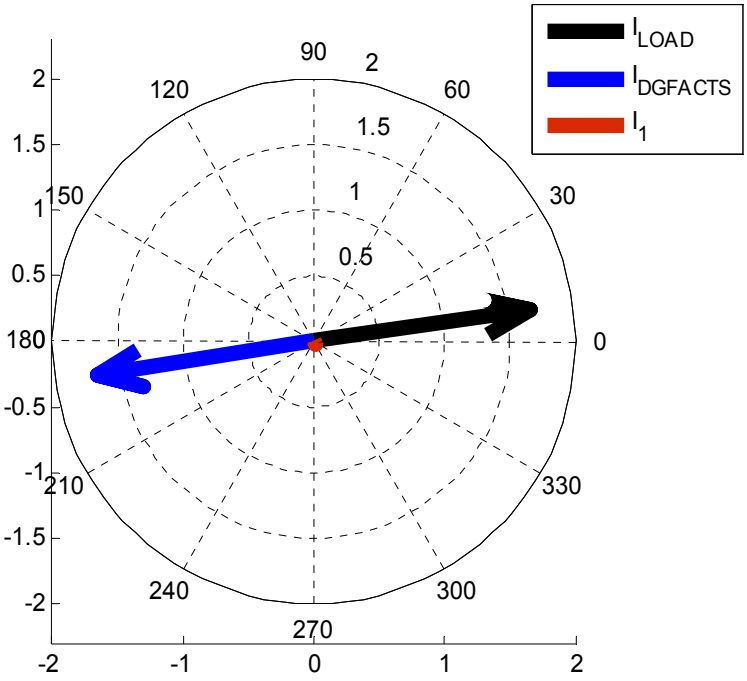


Figure 2-11: Harmonic compensation (3rd harmonic) [DGFACTS 2005]

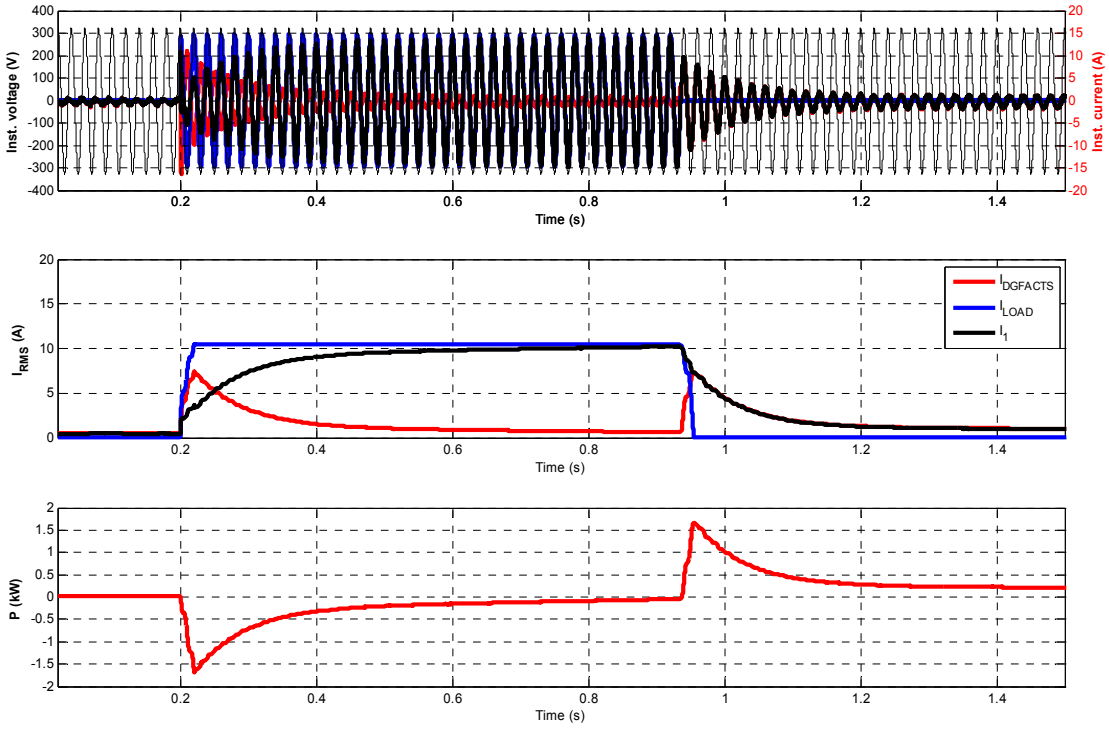


Figure 2-12: Current limitation – switching of a 2.5 kW resistive load [DGFACTS 2005]

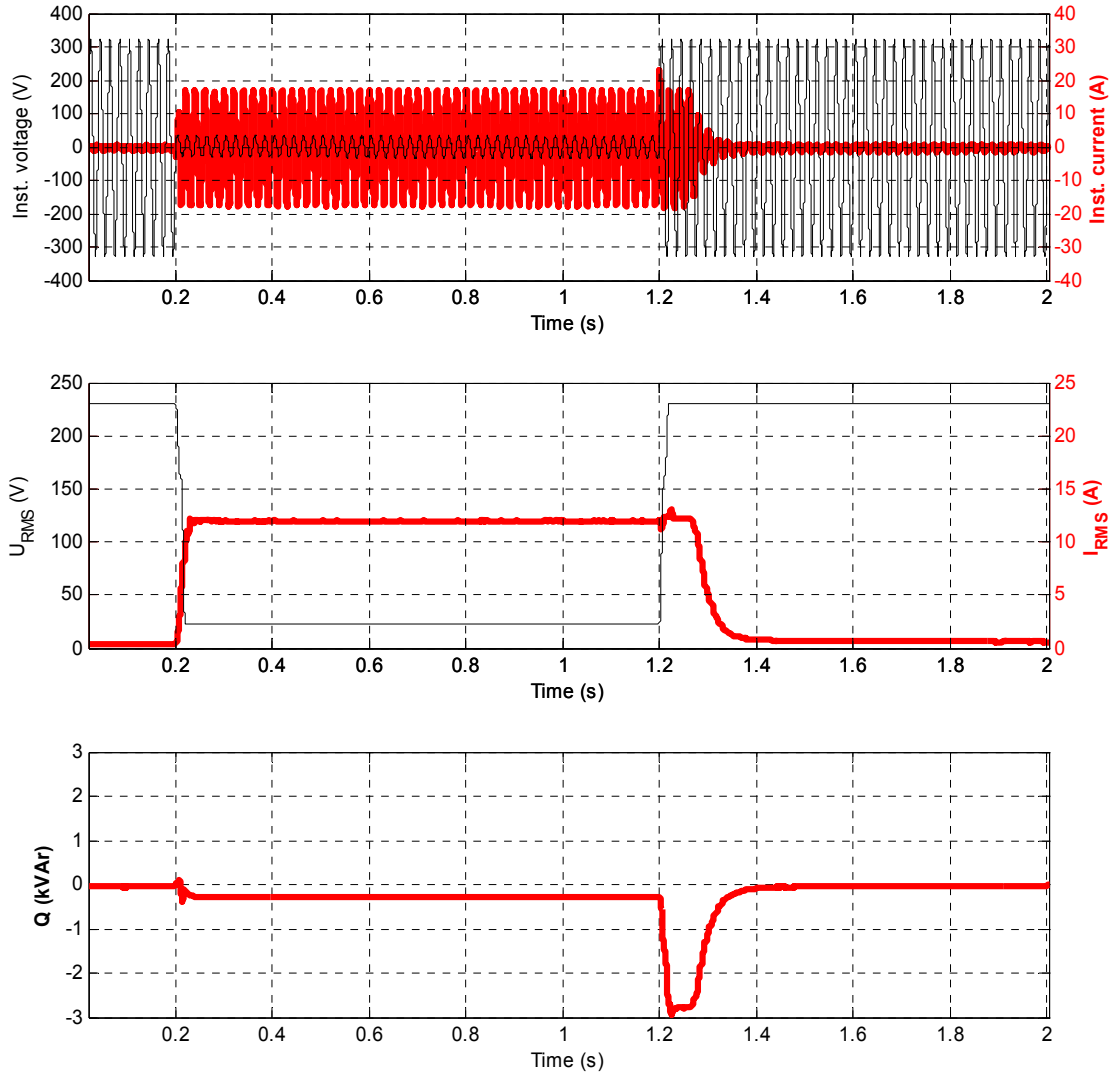


Figure 2-13: Response to a voltage sag to 10% of the rated voltage with a duration of 1 s [DGFACTS 2005]

2.3. Technological Capabilities of Inverter-Coupled Distributed Generators

The previous sub-chapter analyses the technological capabilities of the inverter itself to provide reactive power control, direct frequency control, direct voltage control and improvement of voltage quality. If a DG is analysed as a whole system some restrictions might occur due to the other system elements. Especially, the capability of active power control is dependent on the energy availability and transformation before the final conversion by the inverter. Mainly, the power gradient, the part-loaded operation capability and the active power limitations (maximum and minimum) in the framework of availability and reliability will play key roles in the assessment of the system's capabilities to provide active power control of various time scales.

Table 2-4 presents the results of an analysis of DER units and their technological capability to provide to provide ancillary services with regard to Virtual Power Plants (VPP) in the framework of the FENIX project [Braun 2007a]. The analysis in the present report concentrates on inverter-coupled DER units connected to Microgrids which leads to slightly different results. The technological capabilities of inverter-coupled

- storage units,
- wind turbine generators (WTGs),
- photovoltaic (PV) systems,
- hydro systems and
- combined cooling, heating and power (CCHP) plants

to provide the ancillary services described in Chapter 2.1 are presented in Table 2-5 showing an interesting potential of all inverter-coupled DER units to provide these ancillary service with the exception of thermal-driven CCHP plants which cannot control the active power which is fundamental for grid-forming and frequency control.

Generally, all technologies have the restriction from intermittent renewable energy resources (wind, sun, water, etc.) and storage size. These, normally, underlie fluctuations which result in a reduced availability. However, it is assumed that with an aggregation of several DER units within a Microgrid it becomes possible to aggregate all individual availabilities into one generally better one.

The following chapters review storage units, WTGs, PV systems, Hydro systems and CCHP plants with focus on their

- active power availability,
- active power predictability,
- active power control capability,
- reactive power control capability,
- system reliability, and
- capability to provide ancillary services.

Ancillary Services \ DER Unit	WTG		PV	Hydro		CCHP				Storage		Loads
						thermal-driven		electricity-driven				
Frequency Control		+	+		+		no		++		++	+
Voltage Control, Congestion Management, Optimisation of Grid Losses	Inv	++	++	Inv	++	Inv	+	Inv	++	Inv	++	+
	SG	++		SG	++	SG	+	SG	++	SG	++	
	DFIG	+										
	IG	-		IG	-	IG	no	IG	-	IG	-	
Improvement of Voltage Quality	Inv	++	++	Inv	++	Inv	++	Inv	++	Inv	++	-
	SG	no		SG	no	SG	no	SG	no	SG	no	
	DFIG	+										
	IG	no		IG	no	IG	no	IG	no	IG	no	
Black Start	Inv	+	+	Inv	+	Inv	no	Inv	++	Inv	++	no
	SG	+		SG	+	SG		SG	+	SG	+	
	DFIG	-										
	IG	no		IG	no	IG		IG	no	IG	no	
Islanded Operation	Inv	+	+	Inv	+	Inv	no	Inv	++	Inv	++	no
	SG	+		SG	+	SG		SG	++	SG	++	
	DFIG	-										
	IG	no		IG	no	IG		IG	no	IG	no	
Fault-Ride-Through	Inv	++	++	Inv	++	Inv	++	Inv	++	Inv	++	-
	SG	-		SG	-	SG	-	SG	-	SG	-	
	DFIG	+										
	IG	--		IG	--	IG	--	IG	--	IG	--	

Legend

Grid Coupling Technology
- IG directly-coupled induction generators
- SG directly-coupled synchronous generators
- DFIG doubly-fed induction generators
- Inv inverters (including inverter-coupled IG and SG)

- ++ indicates very good capabilities
- + indicates good capabilities
- - indicates little capabilities
- -- indicates very little capabilities
- no indicates that this is not possible without additional external equipment

Table 2-4: Technological Capabilities of DER units [Braun 2007a]

DG System	Storage	WTG PV Hydro	CCHP (thermal-driven)	CCHP (electricity-driven)
Frequency Control Support	Yes ++	Yes +	No	Yes ++
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes ++	Yes ++	Yes +	Yes ++
Improvement of Voltage Quality	Yes ++	Yes ++	Yes ++	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	Yes ++	Yes +	No	Yes ++

Legend:
- **No** indicates that this is not possible without additional external equipment
- **Yes** indicates that this is possible without additional external equipment
- **++** indicates very good capabilities
- **+** indicates good capabilities
- **-** indicates little capabilities
- **--** indicates very little capabilities

Table 2-5: Technological Capabilities of inverter-coupled DER units connected to Microgrids

2.3.1. Storage

Storage systems can be operated similar to generators as well as similar to loads. Hence, they have characteristics which are formed of the other two. One important limitation is the storage capacity which only allows an oscillating operation between generation and consumption. The objective of the majority of presently installed storage systems is islanded operation in various applications such as small stand alone applications, hybrid systems or emergency power supplies. A large variety of storage technologies are available which are classified in the following paragraphs.

[INVESTIRE 2004] analysed four application categories of storage technologies. It shows that from a purely technical point of view, the best matching storage technology within the application categories can be summarised as follows, where the technology in bold is the most economical one when taking into account the additional cost for electricity.

Category 1: Small stand alone applications: Lithium-ion, **lead acid**

Category 2: SHS and hybrid systems: Lithium-ion, redox flow and **lead acid**

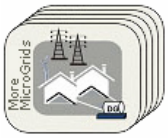
Category 3: Load levelling: Super capacitor and **compressed air**

Category 4: Power quality: **Flywheel**, super capacitor

However some storage technologies are characterised by wide spans in performance parameters meaning that there are different products for different applications. Each technology has its own characteristics that make it suitable for certain niche markets. In these cases, a careful selection of the storage product is necessary.

[INVESTIRE 2004] concludes for each of the storage technologies based on the state of the art:

- Lead acid batteries: Lead acid batteries are cheapest options for off-grid applications and power quality. Future improvements are not very likely, as lead-acid batteries are a proven technology.
- Lithium batteries: Li-Ion storage technology is characterised by high efficiency, which is very important for most categories. Future improvements in investment price are promising, resulting in lower costs of discharged electricity.
- Supercapacitors: This technology is mainly of interest for levelling of power production and power quality. Relatively low losses occur, and for power quality the resulting additional cost could be acceptable in some markets.
- Nickel batteries: Nickel Cadmium batteries are rather expensive and the losses are relatively high.
- Electrolyser, Hydrogen storage and fuel cells: This storage technology is only evaluated for use in village power supply. The additional costs are extremely high, and losses are very important.
- Flywheels: Only adapted for power levelling and power quality, yields relatively low additional costs, which are expected to improve in future.
- Redox flow batteries: The Vanadium redox battery is most adapted for levelling of power production and power quality. For the latter, it is very expensive, but for the first the additional costs are relatively low.



- Pneumatic storage: Compressed air as a storage medium is, according to the evaluation based on the input data as provided by the expert, very well suited for levelling of power production. For village power supply it is rather expensive and not well suited because of its losses.

These storage technologies are inverter-coupled to the grid providing all the capabilities of the inverter. Lead acid batteries, lithium batteries, supercapacitors, nickel batteries, redox flow batteries and all other types of electrochemical batteries are DC sources. They need an inverter for grid coupling. Also flywheels with their large speed variations require power electronic converters between the mechanical generator and the electrical grid.
One type of storage has to be added: mobile storage. Mobile storage terms storage devices of automobiles with electrical motor. Even if this type of storage is not always connected to the network it can be used while connected. Due to the higher overall efficiency of electrical motors in comparison to combustions motors a significant growth can be expected in the coming decades. Presently it is negligible but it the future it has to be included.

The limitations of availability are given by the storage capacity: the larger the storage, the larger the active power flexibility. A storage system needs a good storage management system to be efficient. This storage management system knows the actual status and the limitations of the storage. With this information, it is possible to predict the storage capacity very well.

Table 2-6 summarises the technological capabilities of inverter-coupled distributed storage to provide ancillary services. Each service is described in more detailed in the following paragraphs.

Ancillary Services	Storage
Frequency Control Support	Yes ++
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes ++
Improvement of Voltage Quality	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	Yes ++

Table 2-6: Technological Capabilities of inverter-coupled distributed storage

A big advantage of all storage systems is their direct design for grid support. Presently, they are mostly designed to balance generation and consumption. This capability can be provided acting as a generator or as a load which enhances the active power control capability considerably. Moreover, they are capable of providing other ancillary services because they are inverter-coupled devices.

Their inherent active power control capability makes them suitable for **frequency control support.** While all are capable of providing active power control, economic aspects have to be considered in detail [Oudalov et al. 2007].

Inverter-coupled storage devices can supply reactive power as discussed in Chapter 2.2.2. With this functionality (and their active power control capability in addition) they can provide **voltage control support, congestion management** and **optimisation of grid losses**. The same holds for the capability of **improvement of voltage quality** which depends on the power electronics design (Chapter 2.2.3).

The power electronics coupling together with their active and reactive power control capability allows them to **define voltage and frequency directly** and thereby **forming the grid**. Due to their inherent storage capacity they are also able to **black start**. However, the duration is limited by the storage capacity.

2.3.2. Wind Turbine Generators

Wind power systems are presently booming in Europe. The Wind Energy Report 2005 [ISET 2005] shows for 2004 in Germany that 95% of the installed turbines are pitch-controlled, while only 5% are stall-controlled. Only 8% of the generators are IGs and 92% are speed variable DFIGs (50%) and inverter-coupled SGs (42%).

WTG are using IGs, DFIGs and inverter-coupled SGs. With occuring connection requirements (as described below) especially DFIGs (manufacturers: Vestas, Gamesa, General Electric, Nordex, Repower, DeWind, NEG Micon, Südwind) and inverter-coupled SGs (manufacturers: Enercon, Lagerway, Jeumont, M.Torres) are installed because they can provide the best control performance. Figure 2-14 shows the different types of WTGs. Here, the focus is on inverter-coupled WTGs.

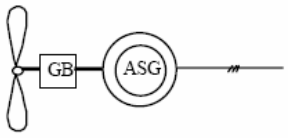
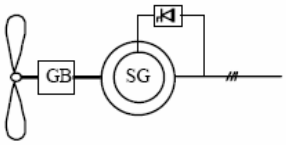
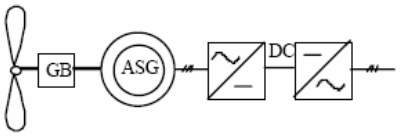
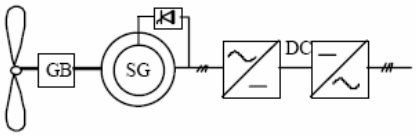
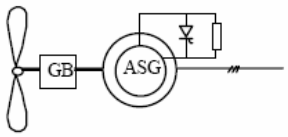
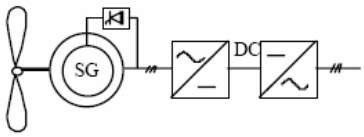
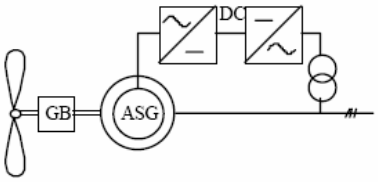
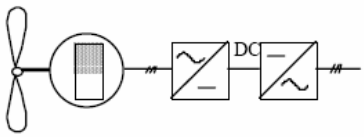
ASYNCHRONOUS GENERATORS	SYNCHRONOUS GENERATORS
• direct grid connection  n = (1-s) f/p s = 0…0.08 inductive reactive power consumer	• direct grid connection  n = f/p controllable reactive power output
• grid connection via DC link  n = 0.8…1.2 f/p controllable reactive power output with suitable converter	• grid connection via DC link  n = 0.5…1.2 f/p controllable reactive power output with suitable converter
• dynamic slip control  n = (1-s) f/p s = 0…0.1…0.3 inductive reactive power consumer	• grid connection via DC link, gear-less  n = 0.5…1.2 f/p controllable reactive power output with suitable converter
• doubly-fed asynchronous generator  	• PMSG connected via DC link  n = 0.6…1.2 f/p controllable reactive power output with suitable converter

Figure 2-14: Different types of WTGs [CIGRE 2000]

With a focus on Microgrids also small WTGs (which have presently a small market share) are looked at. Small WTGs are WTGs with a rotor swept area of less than 200 m² [IEC 2006]. Most of the small WTGs use permanently-excited synchronous generators and are grid-coupled with power electronics (manufacturers: e.g. Aircon, Bergey, Bornay, Eoltec, Fortis, Iskra, Proven, Ropatec, Ropatec, SouthWest, Windpower, Turby, Westwind). The other smaller part uses induction generators (manufacturers: e.g. Conergy, Gaia Wind, SMA, Hannevind, Vaigunth Ener Tek, WES Tulipo) [Kühn 2007]. We focus on the majority of inverter-coupled small WTGs. Further analyses provide [Cano et al 2006].

2.3.2.1. Active Power Availability

In Germany, the monthly averaged capacity factor, which relates the actual energy supply to the theoretical maximum energy supply at full load, shows long-term average values of 15% in the months May to August and 30% in the months January and February (see Figure 2-15). Over the years 1990 to 2004, the maximum monthly value was 45% and the minimum monthly value 7%. The winter in Germany shows significant more wind than the summer. These values change significantly for different locations and different installations of individual WTGs.
The maximum active power generation is site-dependent as displayed in Figure 2-16 for Europe. Large differences exist between the European coastal areas and the continental parts.
Figure 2-17 presents the percentage frequency over the relative variation in the supplied wind power in Germany. The frequency of power changes increases with increasing time intervals. Extreme values of power changes for 15 minutes intervals are approx. 6%, for 1 hour intervals approx. +12/-17% and for 4 hour intervals approx. +27/-40%. Table 2-7 shows the resulting probability of active power changes of [< 1%, < 2%, <5%] for [¼, 1, 4] hour intervals.

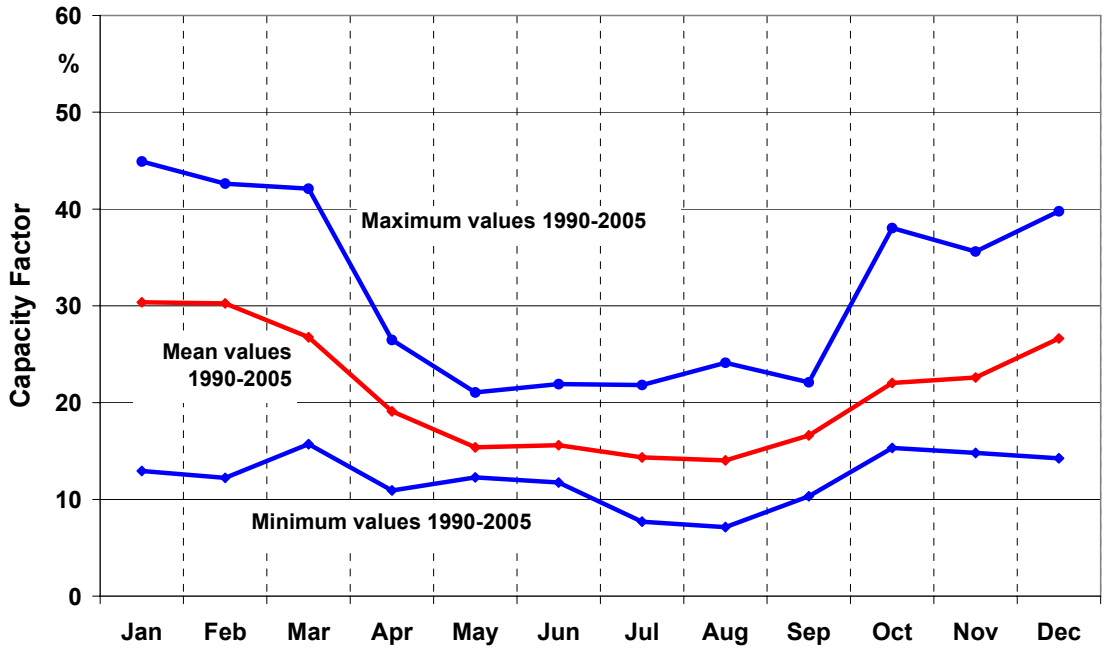


Figure 2-15: Monthly averaged capacity factor of analysed WTGs in Germany [ISET 2005]

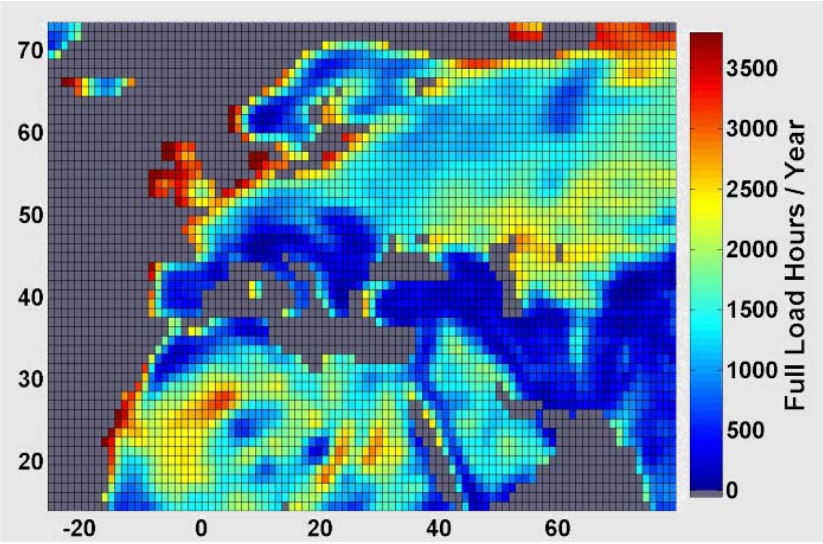


Figure 2-16: Full Load Hours of an exemplary WTG depending on the installation site in Europe [Czisch 2001]

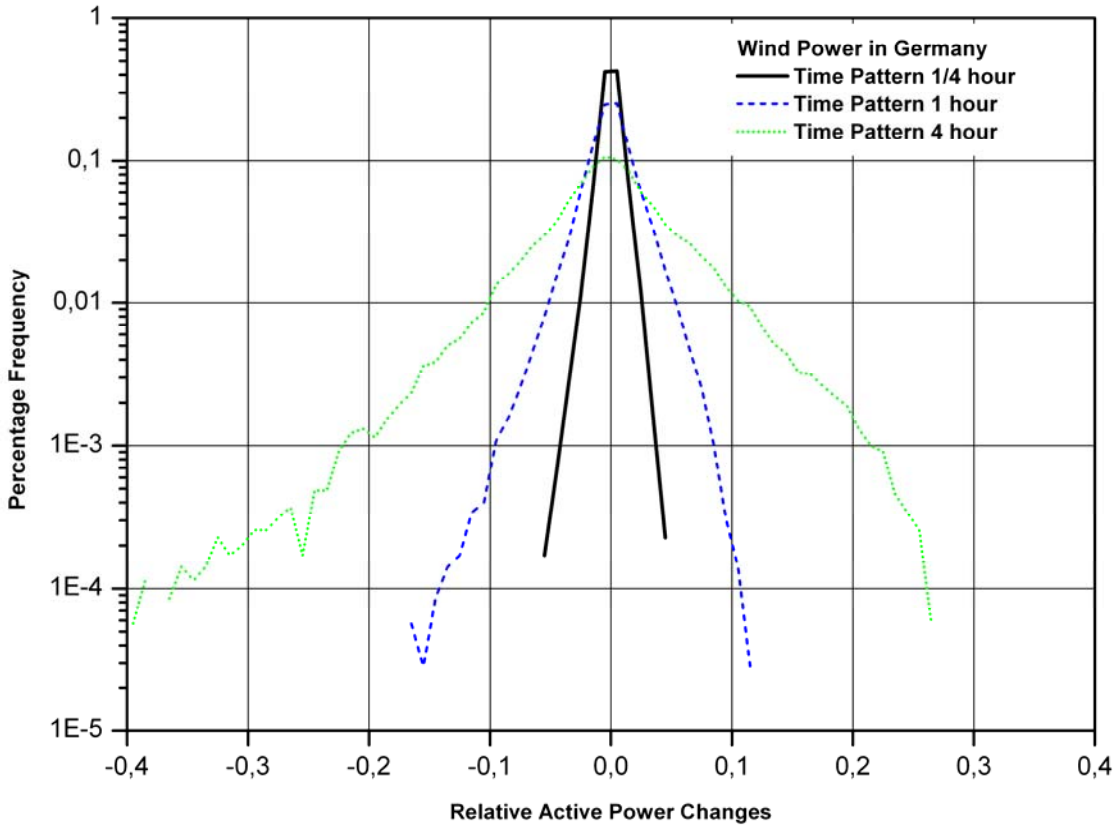


Figure 2-17: Percentage frequency of relative power changes (positive value = power increase; negative value = power decrease) in time intervals of 0.25, 1 and 4 hours (with 15 minutes average values) in Germany [ISET 2005]

Active Power Changes of [< 1%, < 2%, <5%] with a probability of …	**< 1%**	**< 2%**	**< 5%**

for [¼, 1, 4] hour intervals			
¼ hour intervals	84%	97%	100%
1 hour intervals	50%	75%	96%
4 hour intervals	21%	38%	69%

Table 2-7: Probability of Active Power Changes of [< 1%, < 2%, < 5%] for [¼, 1, 4] hour intervals

The levelling of the power generation in widely spread WTG groups is displayed in Figure 2-18. It shows the strong fluctuations of a single WTG as a result of turbulent local weather conditions and the individual plant behaviour. The aggregation of a group of regional WTGs levels the regional weather conditions which show significantly smaller fluctuations and power gradients of the cumulative power generation. These variations are even more smoothed considering the cumulative output of all German WTGs which compensates even regional weather situations. This levelling effect is also demonstrated with percentage frequencies in Figure 2-19 which shows a large bandwidth for a single WTG which decreases with increasing numbers of WTGs.

The quantity and spatial distribution of WTGs in a Microgrid are limited resulting in strong fluctuations and a reduced preciseness of forecast compared to larger interconnected areas. In islanded operation the Microgrid has to face these challenges.

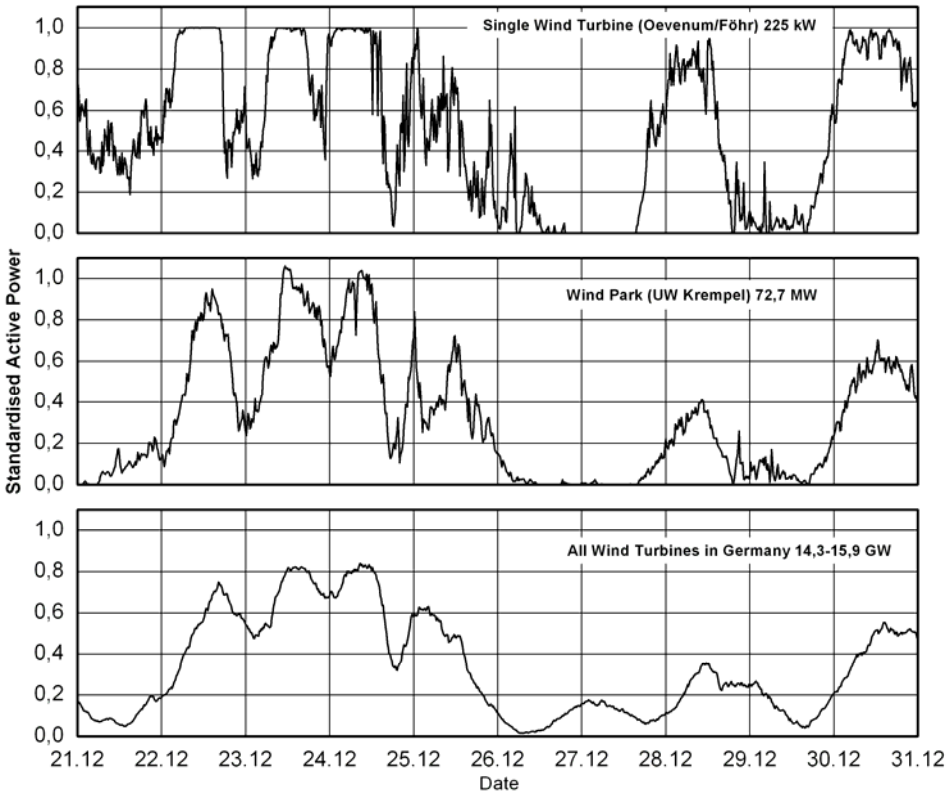


Figure 2-18: Example for the active power (in p.u.) of a single WTG with 225 kW in the upper graph, a group of WTGs with 72.7 MW in the middle graph and all WTGs in Germany with 14.3 – 15.9 GW in the lower graph over the time period 21st – 31st December 2004 (data source: [ISET 2005])

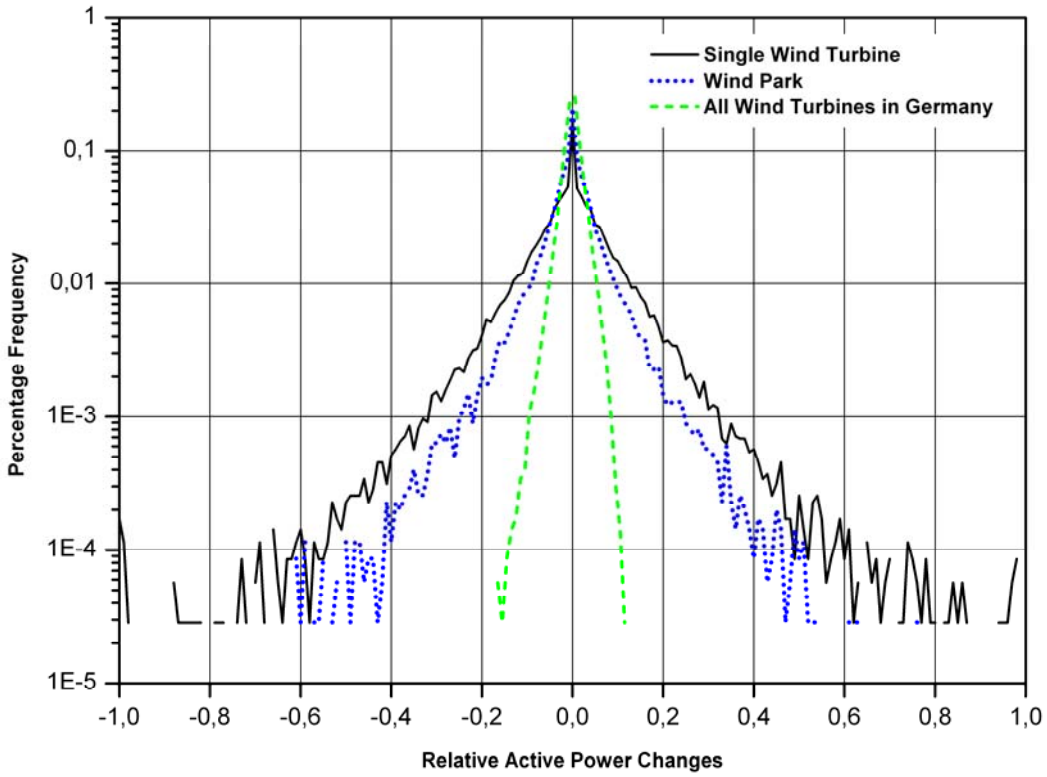


Figure 2-19: Percentage frequency of relative power changes (positive value = power increase; negative value = power decrease) in time intervals of 1 hour (with 15 minutes average values) for a single WTG (continuous line), a group of WTGs (dotted line) and all WTGs in Germany (dashed line) (data source: [ISET 2005])

2.3.2.2. Active Power Predictability

ISET has developed a wind power prognosis system to generate a prognosis of the fluctuating available active power of WTGs. This software tool utilises measurements of representative wind farms for which the wind data is predicted and made available by the German weather service DWD for the next 72 hours (in one hour intervals). With the aid of artificial neuron grids which are trained with data from the past, the expected power is calculated. These predictions of representative sites are extrapolated over the total feed-in of an area. An example of the real and the predicted data is given in Figure 2-20 which shows a good correspondence. Moreover, Figure 2-21 shows the relative distribution of forecast errors with a proportion of 60 – 70% very close to 0%.

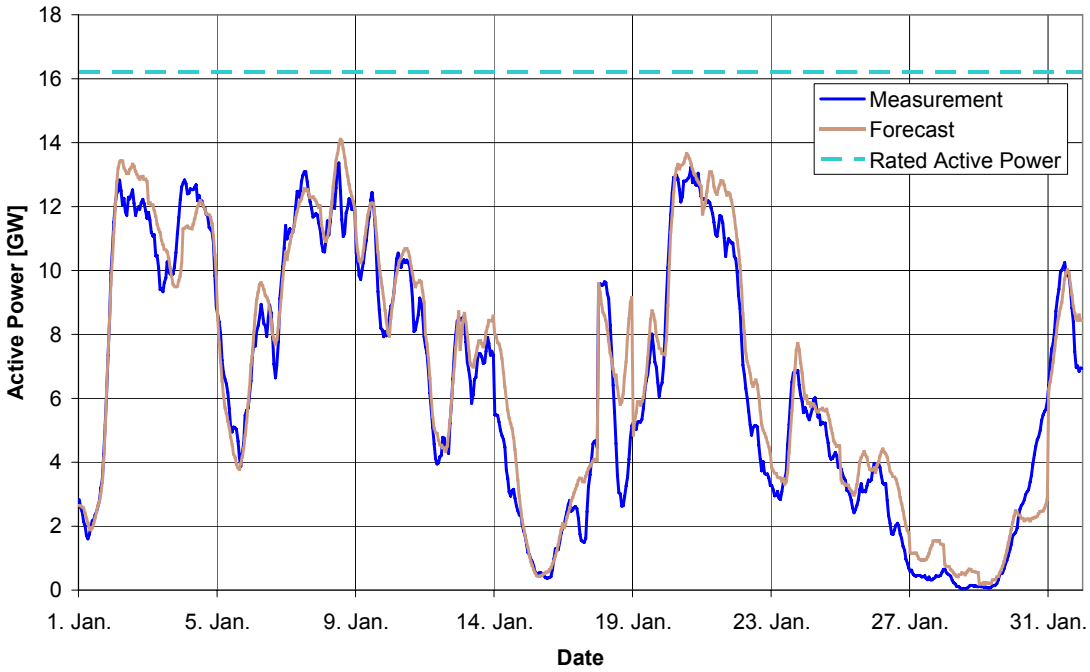


Figure 2-20: Example for the measured (blue line) and day-ahead predicted (orange line) active power production (in GW) of all WTGs in Germany in January 2005 [Rohrig et al 2005]

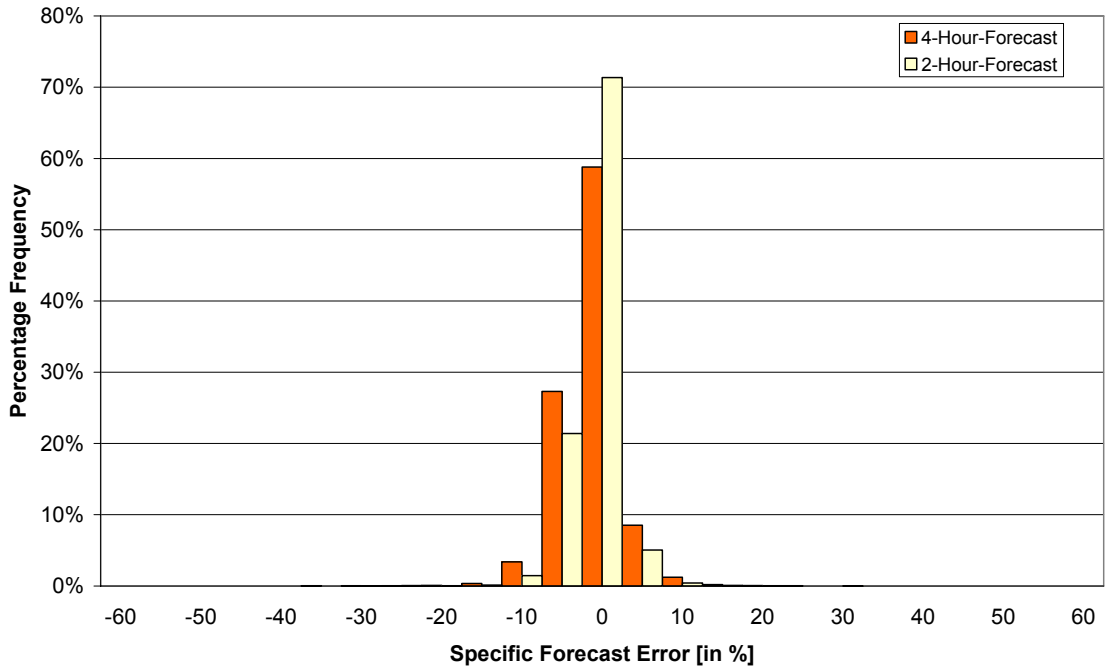


Figure 2-21: Relative distribution of 2-hours-ahead and 4-hours-ahead forecast errors (in% of rated power) of all WTGs in Germany from April 2004 to March 2005 [Rohrig et al 2005]

[Rohrig et al 2005] present the quality of wind energy forecast. Table 2-8 shows the rated root mean square errors for different time horizons (Day-Ahead, 4-Hours-Ahead and 2-

Hours-Ahead) and different grid areas (German mains grid and ENE control area) [Rohrig et al 2005].

	Pm [MW]	NRMSE2 [%]	Pn [MW]	NRMSE1 [%]
Day-Ahead German mains grid	2995	32.4	15387	5.7
Day-Ahead ENE control area	1383	36.6	6741	6.9
4-Hours-Ahead German mains grid	2972	20.3	15387	3.6
4-Hours-Ahead ENE control area	1354	24.9	6741	4.6
2-Hours-Ahead German mains grid	2974	14.9	15387	2.6
2-Hours-Ahead ENE control area	1352	18.8	6741	3.5

Table 2-8: Wind prognosis (April 2004 - March 2005) of different areas and for different time horizons (Pm = medium power; Pn = installed power; NRMSE1 = root mean square error rated to installed power; NRMSE2 = root mean square error rated to medium power)

Figure 2-22 shows the frequency of prediction errors with regard to different aggregation levels. Two general dependencies can be derived on the basis of Figure 2-22 and Table 2-8:

- The forecast error increases with increasing forecast time horizon
- The forecast error decreases with a increasing number of WTGs

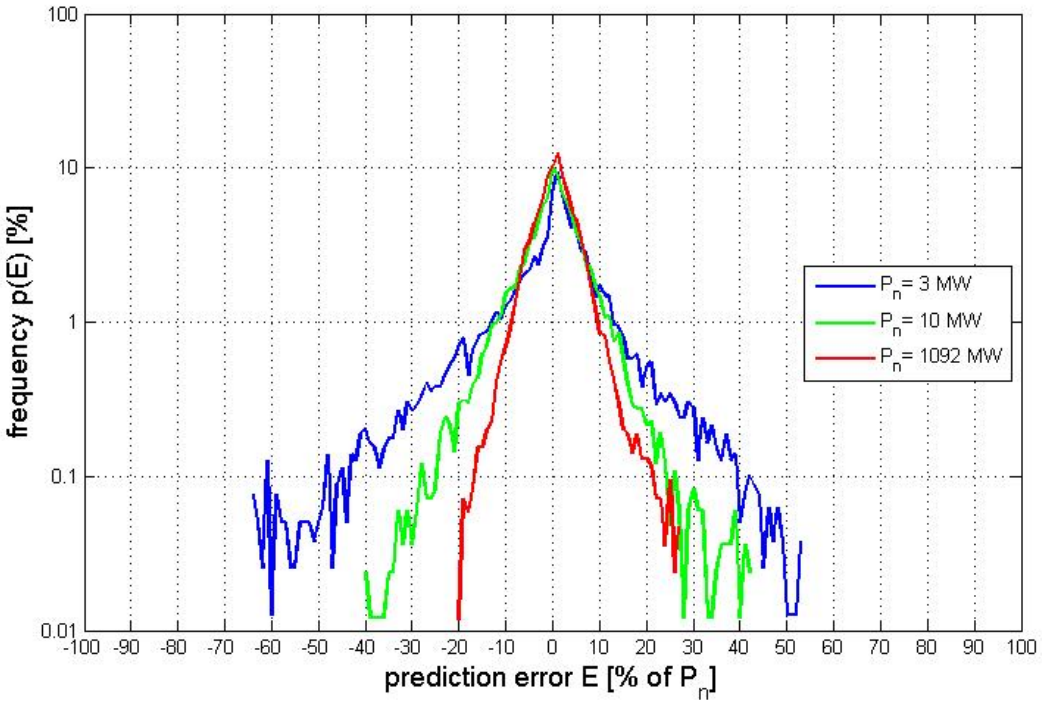


Figure 2-22: Frequency of wind power prediction error [% of rated power] for different aggregation levels [source: K. Knoll, ISET]

2.3.2.3. System Reliability

[ISET 2005] provides data for the technical availability of WTGs in Germany in 2004. Technical availability is the period of availability over the nominal period (in percent). The period of non-availability is the period during which a plant is not functioning due to scheduled maintenance or unscheduled failures. Altogether, a technical availability of 98.1% was achieved in the nominal period 2004 which corresponds to a technical non-availability of 167 hours per wind turbine and year. The age of the WTG demonstrates no significant influence to the technical availability. 43% of the failures have been caused by defect parts, 22% by control system failures and only 15% by external influences (grid loss, storm, lightning and icing) which are site dependent.
The reliability is measured by the frequency of failure and by the period of time required to return to functional operation (related down-time). These two parameters of reliability are given in Figure 2-23 in categories of different components.

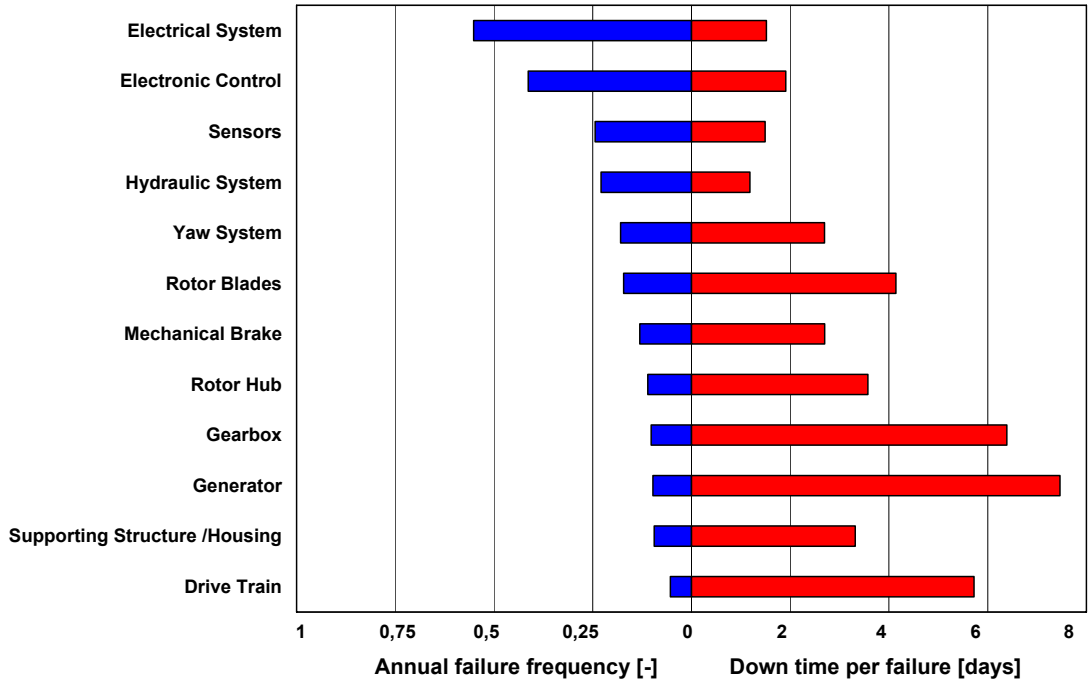


Figure 2-23: Annual frequency of failure (left bars) and down-town per failure in days (right bars) for different wind turbine components [ISET 2005]

[Kühn 2007] analysed the Scientific Monitoring and Evaluation Programme (WMEP) with regard to 235 small WTGs which have been monitored by the WMEP for at least 10 years. The measured reliability is displayed in Figure 2-24. The comparison with newer and larger WTGs shows that the analysed small WTGs have been more susceptible to storms and strokes of lightning. Moreover, small WTGs have an availability of 96% which is less than in case of larger ones. One drawback of the analysed database is that the WTG technology has

progressed enormously and the analysed small WTGs generally represent older turbines. A more detailed interpretation of the data analysis gives [Kühn 2007].

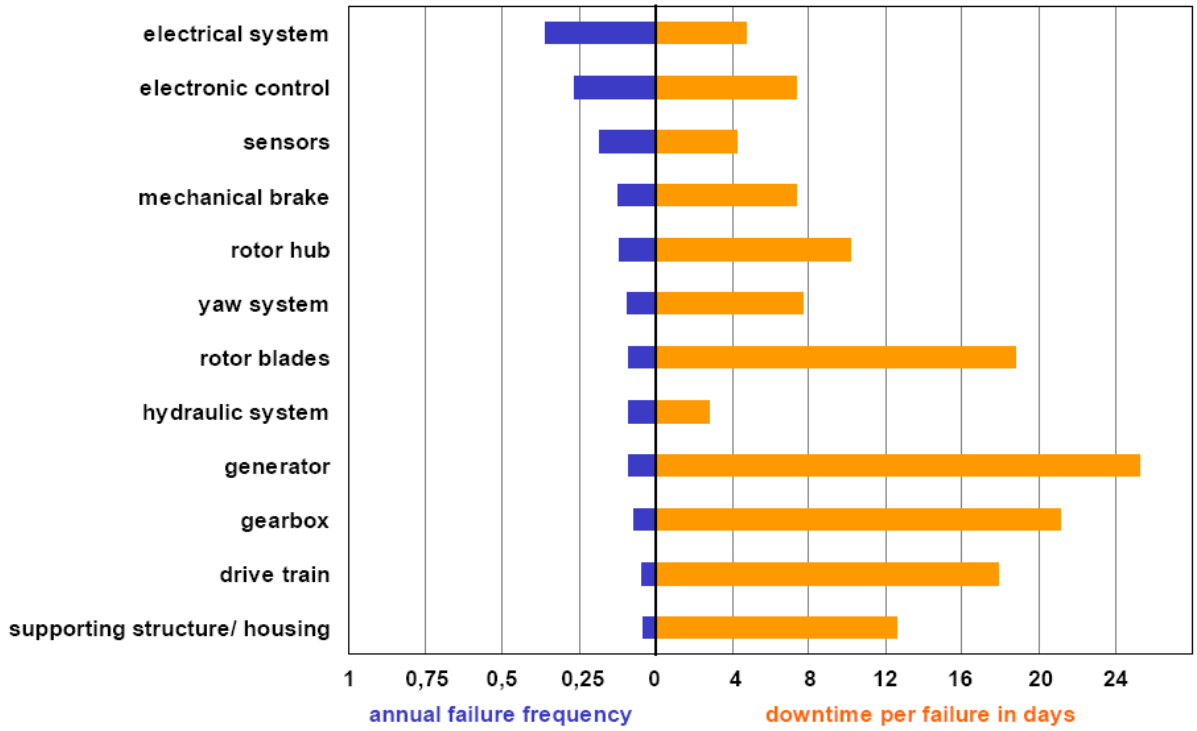


Figure 2-24: Annual frequency of failure (left bars) and down-town per failure in days (right bars) for components of small WTGs [Kühn 2007]

2.3.2.4. Active Power Control Capability

The majority of the installed WTGs are actively pitch-controlled (95% of the additionally installed WTG in 2004 in Germany [ISET 2005]), which allows a control of the mechanical power by changes of the blade angles as described in [Abdad et al 2005], [Holdsworth et al 2004], [Prillwitz et al 2003] and [Prillwitz et al 2004]. While the potential power of the WTG can be calculated by the wind speed measurements, a lower power output given can be found by pitch control. In contrast, passively stall-controlled WTGs have a fixed blade angle without control possibilities. However, actively stall-controlled WTGs have pitchable blades which allow similar to pitch-controlled WTGs a control of the mechanical power limited by the potential power defined by the available wind.

In contrast to large WTGs small WTGs are rarely actively pitch-controlled. In addition they are highly dynamic in their operation because their inertia is quite small. These characteristics leave little opportunities for smooth active power control. Nevertheless, a deactivation and activation allows discrete power control.

Another possibility of power control for wind turbines without pitch control is the yaw control in case of horizontal axis rotors by turning the rotor away from its perpendicular position to the wind resulting in a reduced rotor area faced to the wind. However, its application is difficult because the part of the rotor which is closer to the wind direction will receive a larger force (bending torque) than the other part of the rotor. This results in bending back and forth

in each turn of the rotor, which produces a lot of mechanical stress to the material leading to earlier damages.

State-of-the-art of pitch-controlled WTGs is the definition of active power gradients which are normally set to some percent of nominal active power per second of decrease and increase of active power output in order to reduce network stress [DEWI 2003]. Due to the pitch control speed some ten percent per second would be possible. In emergency situations, almost instantaneous decrease rate can be achieved dependent on the breaker speed. Generally, WTGs have a minimum active power of 0 W and a maximum active power output of the rated active power. The maximum active power output could be lower if the present wind situation shows a lower active power availability or if the system operator defines maximum power injections due to congestions.

An active power control is possible with all wind turbines with pitch-control independent of their gird-coupling technology. As measured in Figure 2-25 and Figure 2-26, the active power control changes are fast enough to fulfil the requirements of primary frequency control. Even in case of critical situations for the voltage limits, active power of wind turbines can be changed fast enough to participate in primary voltage control.

Presently, WTGs operate generally at the maximum available active power. In case of severe problems of grid operation grid operators can limit the active power feed-in. This new maximal active power output value is reached within a couple of seconds as demonstrated in Figure 2-25 with a stepwise decreasing limitation. Moreover, a frequency dependant active power limitation can be applied to provide high frequency response as measured in Figure 2-26.

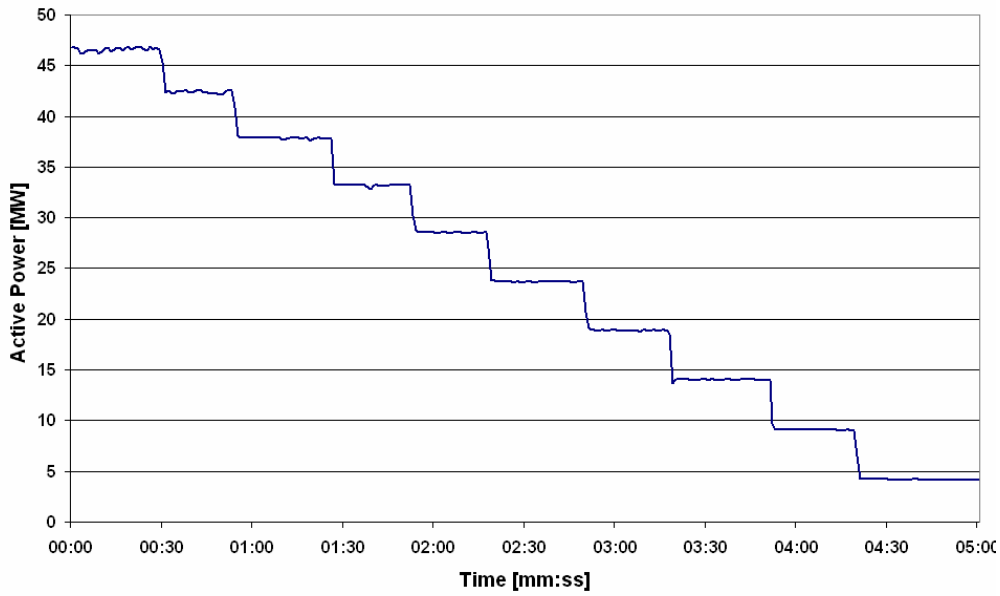


Figure 2-25: Limitation of the active power output of an Enercon E-66 wind farm with 50 MW by external target values in decreasing steps of 10% [Hartge et al 2005]

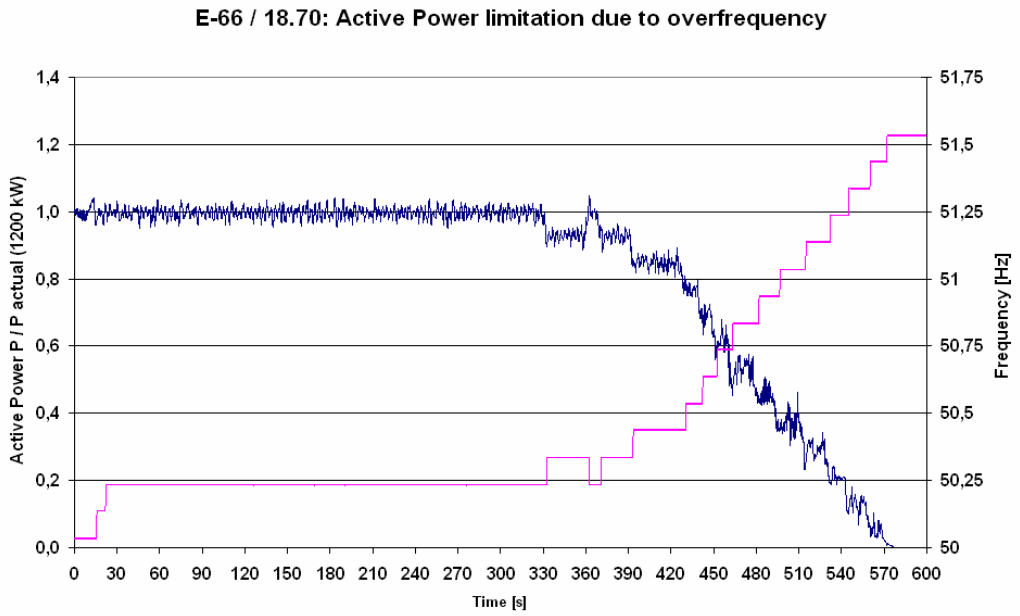


Figure 2-26: Frequency dependent limitation of the active power output of an Enercon E-66 wind turbine (rated active power in blue; frequency in lily) [Hartge et al 2005]

Speed-variable WTGs with active power control reserve cannot operate at the maximum available or maximum allowed active power operation point. They have to operate below the maximum to have active power reserves for low frequency response. New control algorithms have to be implemented for the control of these innovative WTGs [Abdad et al 2005], [Holdsworth et al 2004], [Prillwitz et al 2003] and [Prillwitz et al 2004].

Basically, the mechanical power P of the WTG is defined by

$$P = \frac{1}{2} \cdot \rho \cdot \pi \cdot R^2 \cdot v^3 \cdot C_P(\lambda, \beta) \qquad (2\text{-}7)$$

This equation comprises the air mass density ρ, the rotor radius R, the wind speed v and the power coefficient C_P which is dependent from the tip speed ratio λ and the pitch angle β. The function of the power coefficient C_P is displayed in Figure 2-27. While the pitch angle can be changed by the pitch control, the tip speed ratio can be modified by changing the rotation speed of the wind turbine Ω:

$$\lambda = \frac{\Omega \cdot R}{v} \qquad (2\text{-}8)$$

At the maximum power coefficient, the maximum power from the available wind condition will be generated by the WTG. Present WTG operate at this maximum power coefficient if they receive no power limitation signals by the grid operator. By varying the tip speed ratio and/or the pitch angle they are able to operate below the maximum in case of limitation signals or to have reserve to provide positive active power control. According to the studies in [Abdad et al 2005], both strategies produce similar results. However, they highlight that pitch variation does not change the rotation speed of the wind turbine in constant wind conditions. The advantages are

- a better stability of the whole system,

- a bigger power compensation capacity of the WTG, and
- a faster compensation dynamic.

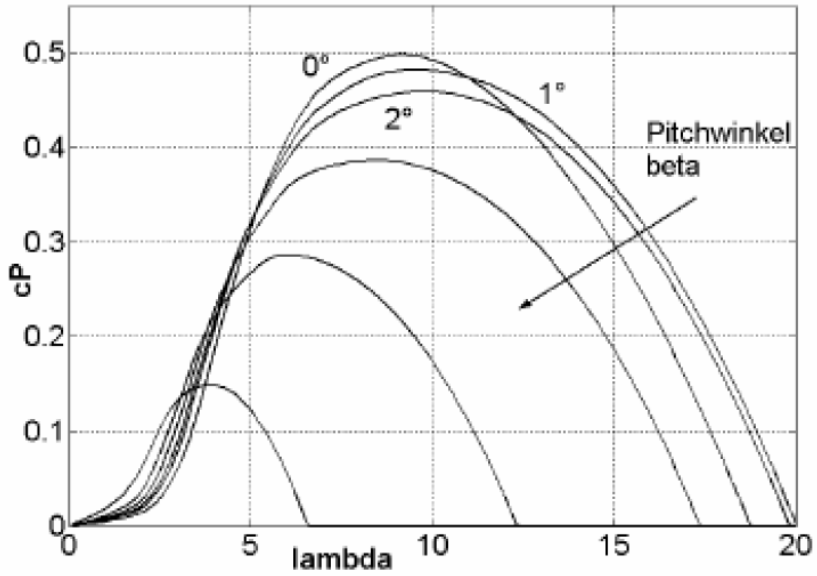


Figure 2-27: Power coefficient C_P for different pitch angles beta (0°, 1°, 2°, …) and the tip speed ratio lambda [Prillwitz et al 2004]

Figure 2-28 shows the mechanical power of the WTG over the rotation speed at different wind speeds. Moreover, different pitch angles (0°, 1° and 2°) show the difference of the mechanical power which decreases for higher pitch angles. The control characteristic lines for different pitch angles beta (0°, 1°, 2°) give the stationary operating points. The WTG operator defines an optimal control characteristic line for normal operation which guarantees maximal power output. This would be β = 0° in Figure 2-28. If active power reserve should be considered, another control characteristic line should be used. In Figure 2-28, for instance, the control characteristic line with β = 1°. Figure 2-28 displays simplified control characteristic lines which are non-linear in reality and dependent on the turbine's geometry. In order to provide a stable active power change, an increase of the mechanical power should reduce the rotation speed (feed-in of rotational energy) while a power decrease should increase the speed (absorption in rotational energy).

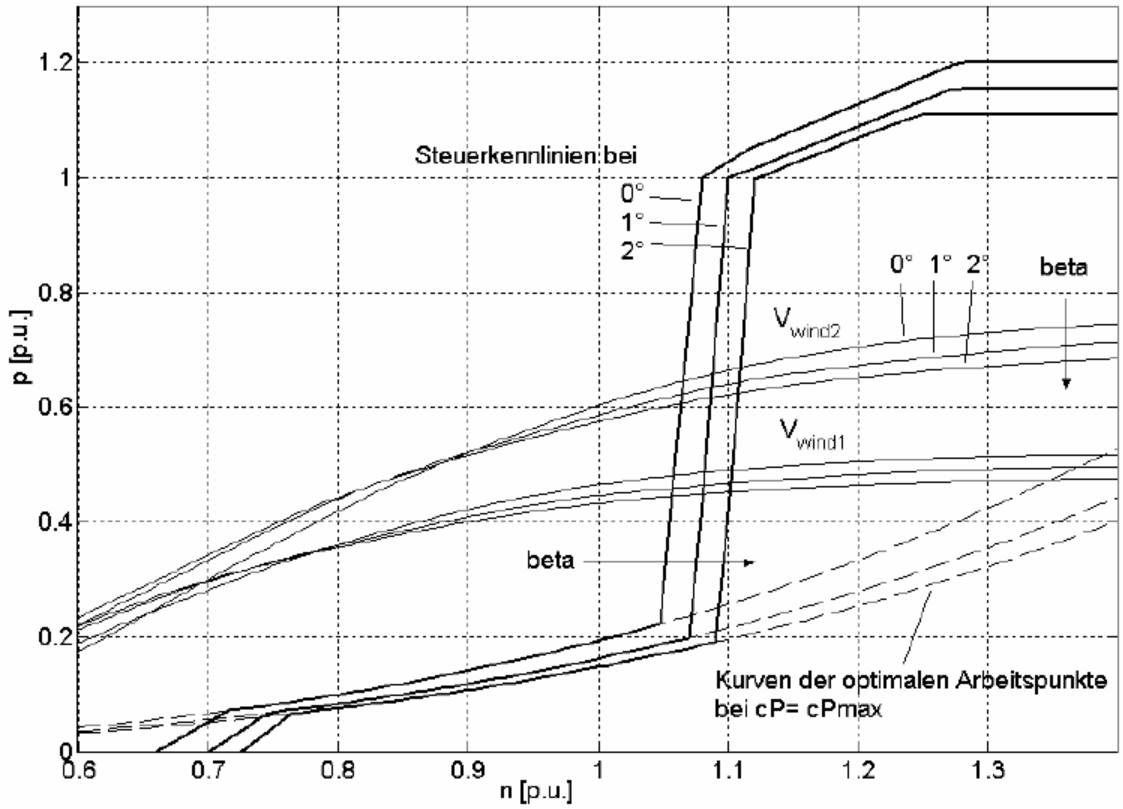


Figure 2-28: Rated mechanical power p over the WTG rotation speed n for different wind speeds v_{wind1} and v_{wind2}; and control characteristic lines for different pitch angles beta (0°, 1°, 2°) [Prillwitz et al 2004]

[Holdsworth et al 2004] propose a pitch angle controller for frequency response which is shown in Figure 2-29. Two control regions are distinguished:

- Region A — above rated output power
- Region B — below rated output power

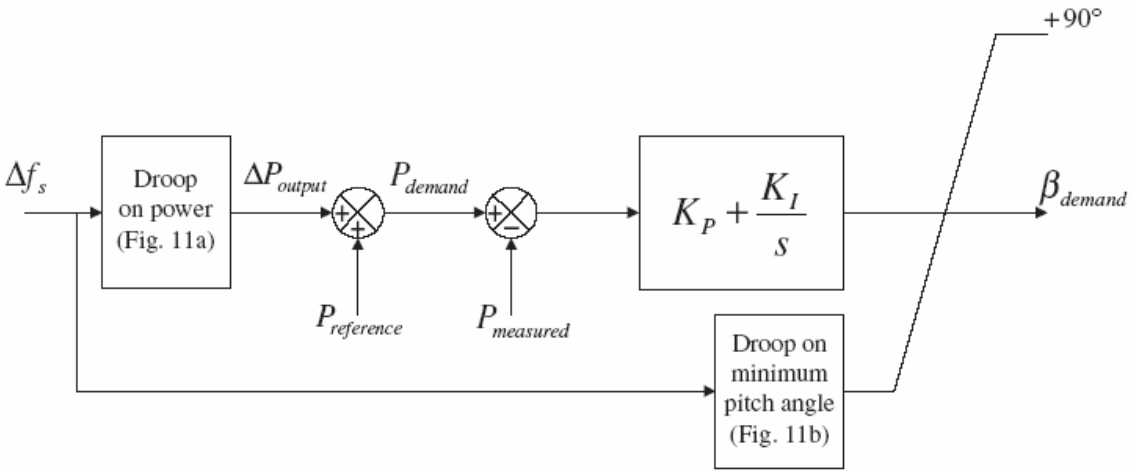


Figure 10. Proposed pitch angle controller for frequency response from wind turbines

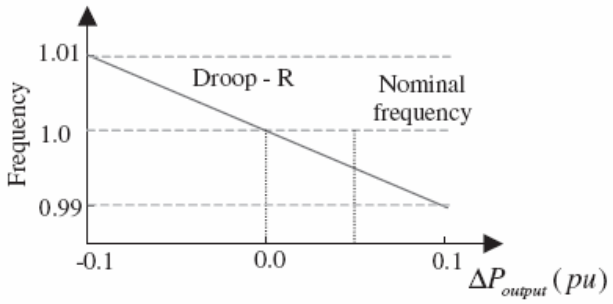


Figure 11(a). Droop on power

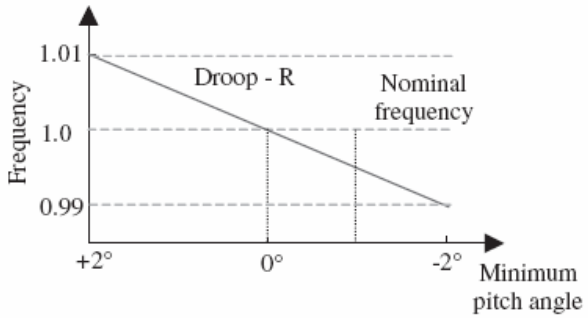


Figure 11(b). Droop on minimum pitch angle

Figure 2-29: Pitch Angle Controller for Frequency Response from WTGs [Holdsworth et al 2004]

Region A — above rated output power:

Consider a turbine without frequency response. Above rated output power (region A) the pitch-to-feather scheme is in operation with positive values of the pitch angle, which are already 'spilling' power to maintain the output at the defined $P_{reference}$. For the frequency response control, $P_{reference}$ is reduced to unload the wind turbine by 10% for a system frequency of 50 Hz. In response to frequency deviations, ΔP_{output}, defined by a droop characteristic, is added to $P_{reference}$ to obtain P_{demand}.

Region B — below rated output power:
With $P_{reference}$ selected as 90% of rated output power, P_{demand} is always greater than that which can be generated in this region ($P_{measured}$). This results in driving the PI output towards the defined minimum pitch angle limit. For deviations in system frequency the minimum pitch angle limit was regulated on a second droop characteristic.

The operation of the controller can be described as follows. Operating in region A, a change in frequency of Δf = -0.5 Hz will result in a change in reference power of +10% rated, where the pitch-to-feather control will now maintain the rated output power. Similarly, a change in system frequency of Δf = +0.5 Hz will result in a change in reference power of -10% rated, where the pitch-to-feather control now maintains 80% of rated output power.
In region B, if there is a change in system frequency while operating below rated output power, then the minimum pitch angle will change proportionally to the change in frequency. However, this is limited to pitch angles of +/-2°. For example, a drop in frequency will result in the controlled pitch angle approaching, but limited to, -2°, which will result in increased output power from the turbine. Similarly, an increase in frequency results in a pitch angle approaching, but again limited to, +2°, which 'spills' available wind power and therefore reduces the output power.

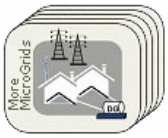
2.3.2.5. Reactive Power Control Capability

As already discussed at the beginning of the chapter the reactive power control capability mainly depends on the grid coupling converter. Principal WEC designs [CIGRE 2003] are

- directly-coupled induction generators (IGs) in fixed speed or variable slip design with capacitor banks;
- doubly-fed induction generators (DFIGs) with a power electronics converter between the point of grid connection and the rotor circuit of the IG (designed only with a fraction of the rated power);
- directly-coupled synchronous generators (SGs) with a variable gearbox and excitation control; and
- inverter-coupled generators with a full power electronics converter (FC) which couples different designs of induction and synchronous generators.

The focus here is on the two market-dominating [6] power electronic designs: DFIG and FC. While the capabilities of the FC have already been explained in detail in Chapter 2.2.2 the capabilities of a DFIG are shortly explained in the following.

The DFIG comprises an IG and an inverter. A principal structure is presented in Figure 2-30. DFIGs are IGs which behave as SGs from the grid point of view, rotating at variable mechanical speeds. These generators are considered as a mix between SGs and IGs, since they have a rotor excitation like SGs and they require grid variable voltage to magnetise the rotor like IGs.
The AC/DC/AC converter is divided into two components: the rotor-side converter and the grid-side converter which are voltage-sourced converters. A capacitor connected on the DC side acts as the DC voltage source. The three-phase rotor winding is connected to the rotor-side converter by slip rings and brushes and the three-phase stator winding is directly connected to the grid. This design allows an excitation in the rotor coils for speed regulation and reactive power control of the IG by the rotor-side inverter as well as reactive power supply by the grid-side inverter. The control system generates the prime mover control command and the voltage command signals for the two converters. These commands allow controlling the active power output of the DFIG, the DC bus voltage, the reactive power



output, and the voltage at the grid terminals.
DFIG is a popular generator among the leading WTG manufacturers, because of variable speed, possibility of reactive power control and because power electronics only handles a fraction (20% approx.) of the full power which results in lower losses of electronic converters and lower costs for electronic converters, in comparison to directly inverter-coupled technologies.

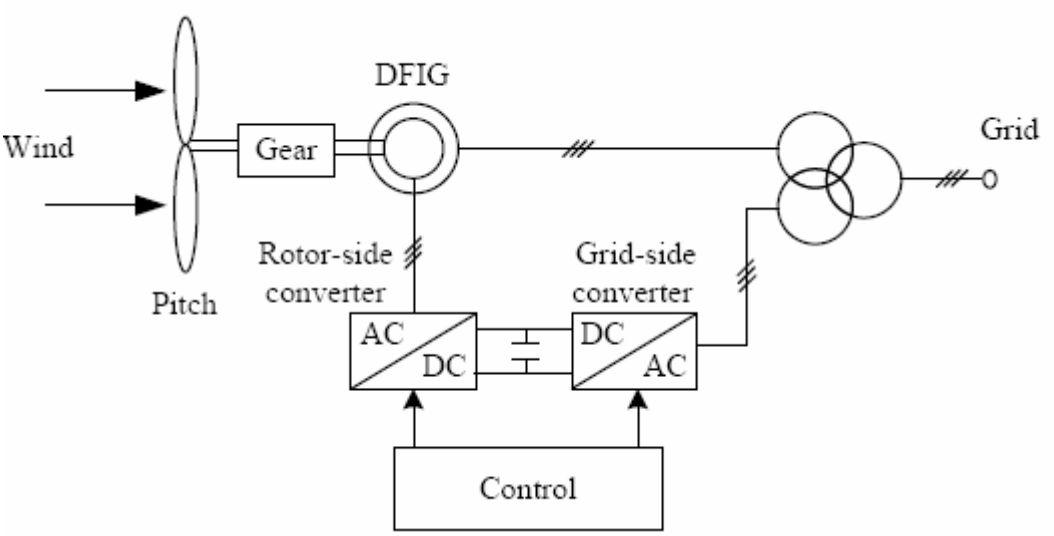


Figure 2-30: Structure of a DFIG of a WTG [Wang 2005]

Three limits define the reactive power capacity of a DFIG [Lund et al 2007]:

- stator current (heating of stator coils)
  → S_{max} (green), Q_{min} (blue, left-hand side),
- rotor current (heating of rotor coils)
  → Q_{max} (blue, right-hand side), and
- rotor voltage (limiting the rotor speed).

The rotor voltage can be a limit at high slip s, reducing Q_{max} further on. Figure 2-31 shows the loading capability chart at s = 0. At lower slip the defining circles are extended in direction of the P axes (and compressed at higher slip). A detailed discussion on the functional dependencies provides [Lund et al 2007].

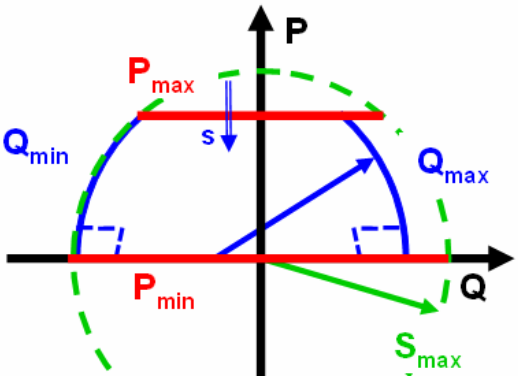


Figure 2-31: Loading capability chart of a DFIG
(Q > 0: capacitive)

Inverter-coupled WTGs are capable to provide fast changes of reactive power supply or consumption due to the control capabilities of the inverter (cf. Chapter 2.2.2). The limitations are the maximum current transfer of the inverter and stability considerations. These limits have to be taken into account to optimise the power control. According to Grid Codes manufacturers implement more and more enhanced reactive power control capabilities. The evolution is described exemplarily by looking at one manufacturer: Enercon.

The Enercon E-70 WTG has the reactive power limits as displayed in Figure 2-32. It shows the variation possibilities within this funnel of +/- 50% of the active power output depending on the respective wind conditions.

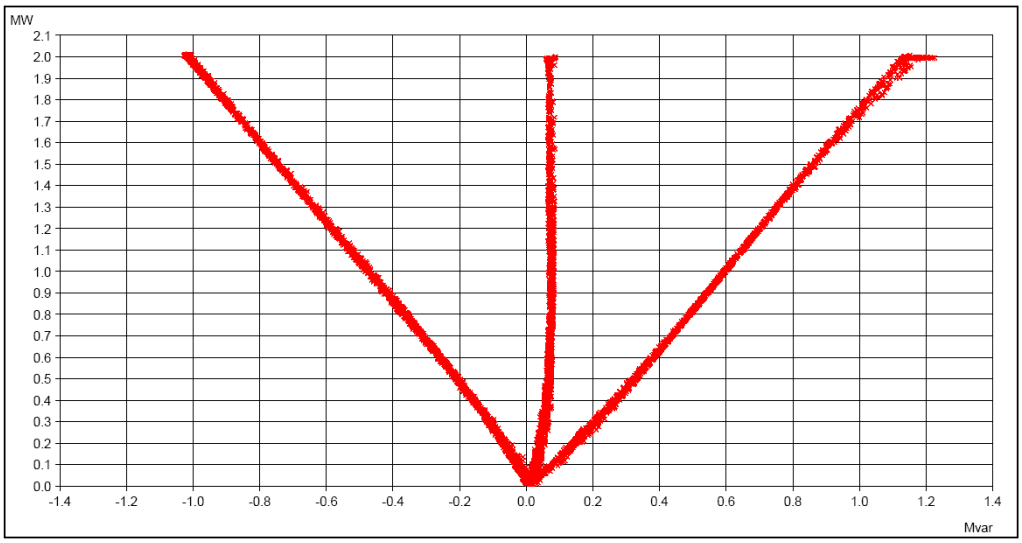


Figure 2-32: Reactive power limits depending on the active power output of the Enercon E-70 WTG [Hartge et al 2005]

[Hartge, Fischer 2006] and [Wachtel;Hartge 2007] present more advanced reactive power control capabilities of Enercon E-70 WTGs which have a “STATCOM inside solution”. They refer this capability to STATCOMs which are voltage source inverters and are installed in transmission grids to compensate reactive power flows to guarantee that the voltage stays within the allowed limits. With this “STATCOM inside solution”, the WTGs are able to provide reactive power dispatch to the grid operators. Moreover, this ENERCON STATCOM can also provide dynamic reactive power supply in case of transient over- and undervoltages as well as voltage vector jumps at the terminals of the WTG. As an advantage to the possibilities of reactive power control by the E-70, the STATCOM configuration allows a reactive power control capability of +/- 50% (+/- 1.15 MVAr) of the rated active power, independent from the wind conditions up to an active power generation of 2.2 MW (Figure 2-33). At an active power generation of 2.3 MW, the reactive power control capability is reduced to +/- 30% (+/- 0.69 MVAr). In comparison with the theoretical active/reactive control capability as presented in Figure 2-6, the inverter dimensioning has to be more than 2.3 MVA. This results from the operation points:

- P = 2.3 MW, Q = 0.69 MVAr $\rightarrow$ S = 2.4 MVA
- P = 2.2 MW, Q = 1.15 MVAr $\rightarrow$ S = 2.5 MVA

Consequently, the inverter capacity should be at least 2.5 MVA, which corresponds to an over-dimensioning of at least 8%.

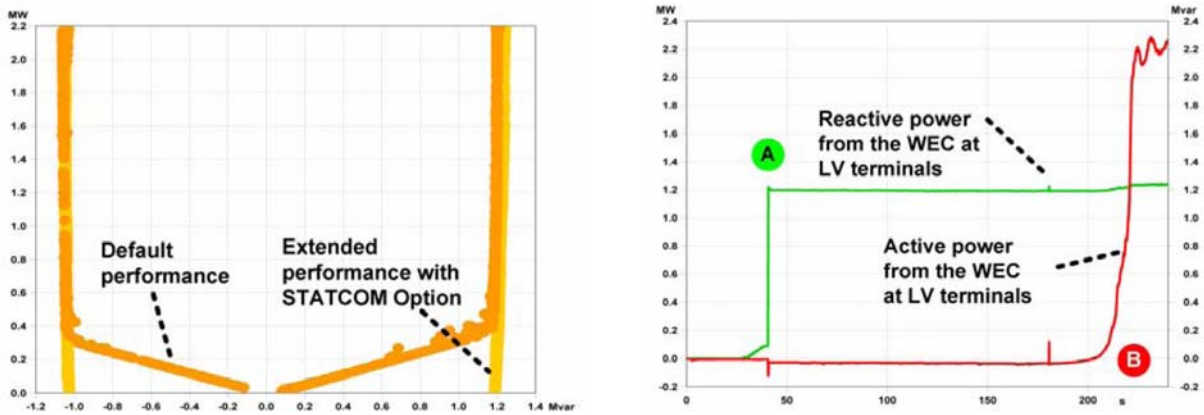


Figure 2-33: Reactive power supply capability of a Enercon WTG with STATCOM option [Wachtel;Hartge 2007]

The absolute maximum of reactive power supply can be extended up to the limit given by S_{max}. However, the availability might be dependent on the actual active power transfer so that not 100% availability can be stated but less according to equation 2-6.
As an exemplary database, the measurements of an Enercon E-66 WEC (with P_{max} = 1300 kW) in Germany are analysed. For each five minute interval, the maximum active power is measured in the years 2001-2003. The maximal reactive power Q_{max} is calculated with equation 2-6 for different inverter sizings S_{max}. This leads to the availability of a certain reactive power Q as displayed in Table 2-9 showing the influence of oversizing the inverter. With S_{max} = 1400 kVA = 1.077 P_{max} it is possible to guarantee 520 kVAr and with S_{max} = 1500 kVA = 1.154 P_{max} even 748 kVAr for the full active power operation range. More reactive power can be supplied but the availability is less than 100% but still more than 90% up to 1000 kVAr.

This comparison with real measurement data and with assumption of the inverter dimensioning show a high potential of reactive power production/absorption which results from the intermittent behaviour of the wind power generation which utilises most of the time not the full potential of the inverter. The exact potential depends on the inverter dimensioning, the WTG characteristics and the wind characteristics of the respective plant site. The presented comparison is only an example with certain assumptions which shows the mostly unused reactive power potentials.

Q kVAr	Availability of Q with S_{max} = 1300 kVA	S_{max} = 1400 kVA	S_{max} = 1500 kVA
100	>99%	100%	100%
200	>99%	100%	100%
300	>99%	100%	100%
400	99%	100%	100%
500	97%	100%	100%
600	95%	>99%	100%
700	94%	98%	100%
800	94%	95%	>99%
900	93%	94%	97%
1000	92%	93%	94%

1100	89%	92%	94%
1200	84%	90%	93%
1300	5%	85%	90%
1400	0%	5%	86%
1500	0%	0%	5%

Table 2-9: Availability of reactive power Q [kVAr] of an Enercon E-66 WEC (with P_{max} = 1300 kW) in Germany with different inverter sizings S_{max}

2.3.2.6. Capability to Provide Ancillary Services

Table 2-10 summarises the technological capabilities of WTGs to provide ancillary services. Each service is described in more detail in the following paragraphs.

Ancillary Services	WTG
Frequency Control Support	Yes +
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes ++
Improvement of Voltage Quality	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	Yes +

Table 2-10: Technological Capabilities of WTGs

Due to the active power control capability of WTGs presented in Chapter 2.3.2.4 **frequency control support** of all time scales is technologically possible. A disadvantage is the intermittency presented in Chapter 2.3.2.1. This disadvantage can be reduced by forecasting and aggregation: the shorter the time scale and the higher the aggregation the smaller the forecast error. One limitation of active power control is given by the primary energy fluctuations which limit the availability to forecast preciseness for different time horizons. Nevertheless, it is possible to say that within a certain probability the power generation would be within a certain bandwidth.

Voltage control support, congestion management and **optimisation of grid losses** by WTGs is mainly based on the reactive power control capability which is described in Chapter 2.3.2.5 and, of secondary priority, the active power control capability discussed in Chapter 2.3.2.4. Based on these capabilities these ancillary services can be provided effectively.

Improvement of voltage quality by inverter-coupled WTGs is possible as described in Chapter 2.2.3.

Because of the primary energy fluctuations the contribution to energising the grid will not be constant and therewith a challenge to the control of a **black start**. However, generally, black start by WTGs using an inverter-coupled SG is possible because they can start without the network due to the inverter's capability of **direct frequency and voltage control** and the available kinetic energy source (wind). [Skytt et al 2001] show the black start with the Tjæreborg wind farm (see Figure 2-34). Together with the active and reactive power control

capabilities **grid-forming** and islanded operation is possible but restricted due to the availability of active power (of wind) which is described in Chapter 2.3.2.1. According to the forecasted wind energy only a reduced active power with a security reserve and active power control reserve is available for islanded operation.

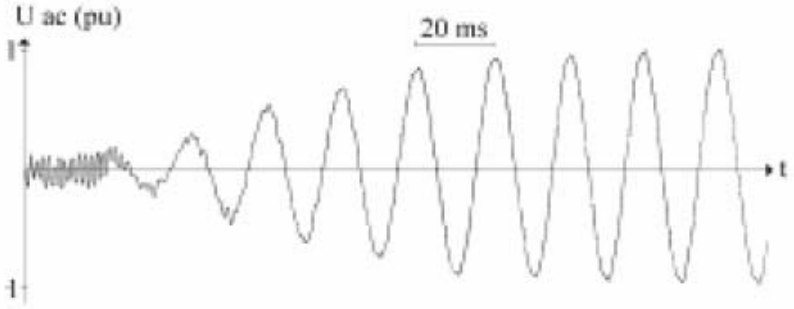


Figure 2-34: AC voltage at start-up of an isolated network (measurements from the Hällsjö project) [Skytt et al 2001]

2.3.3. Photovoltaic Systems

2.3.3.1. Active Power Availability

Similar to WTGs, PV systems are dependent on a primary energy source with its fluctuations. While the wind in Germany is more intensive in the winter months, the PV systems produce more energy in the summer months. PV systems show also a typical behaviour each day. At night, they do not operate at all and in the hours of sunshine their generation varies according to the irradiation of the sun. This is dependent on the orientation of the modules relative to the irradiation and the actual weather conditions. Figure 2-35 shows exemplarily the active power generation of a PV system for one week in June and one week in December 2006 in Kassel, Germany. The availability of active power depends on the site (cf. Figure 2-36), the system itself (module orientation, cell technology, inverter etc.) the season (cf. Figure 2-37) and the actual weather conditions (cf. Figure 2-35).

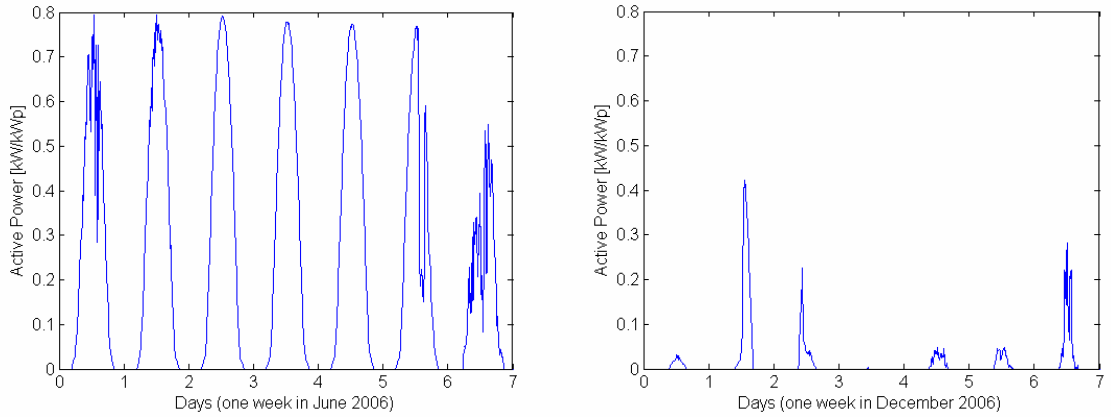


Figure 2-35: Measurements of the PV active power generation in Kassel, Germany, during one week in June (left) and one week in December (right) 2006 (data: ISET measurements)

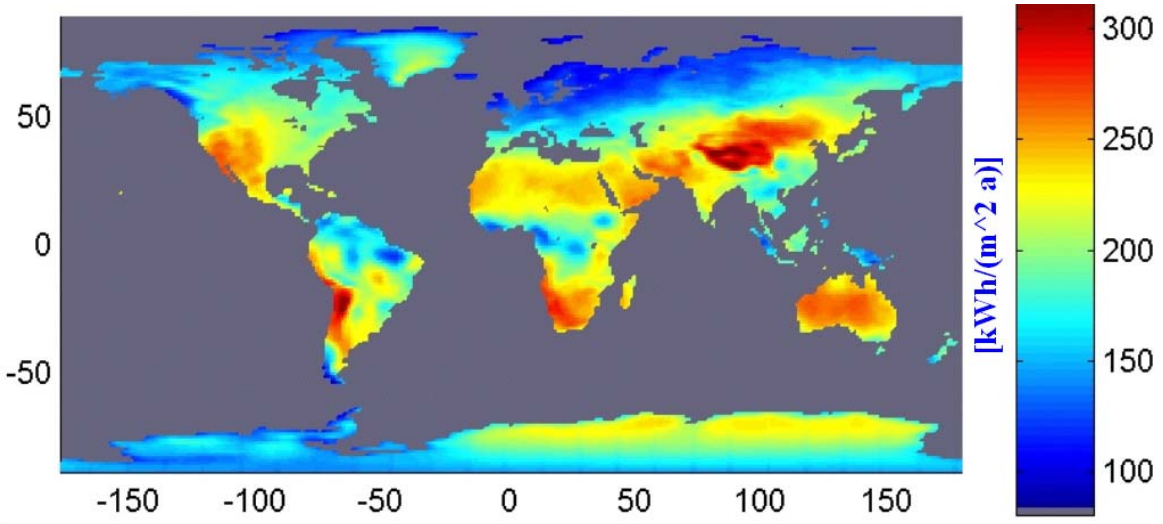


Figure 2-36: Annual Average Potential Electricity Production [kWh/m²/a] with PV (1983 – 1992) [Czisch 2001]

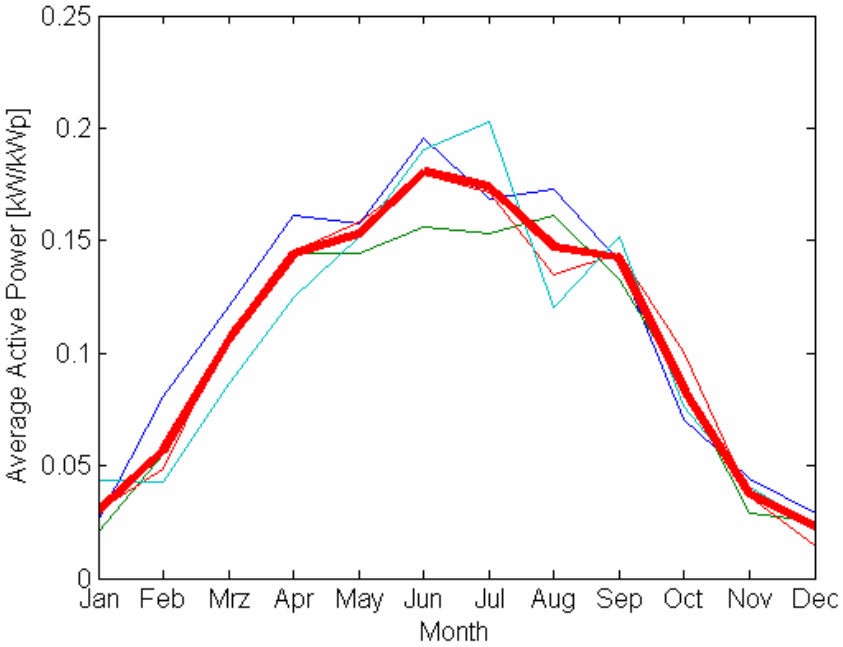


Figure 2-37: Monthly PV active power generation in Kassel, Germany, during 2003 – 2006 (data: ISET measurements)

2.3.3.2. Active Power Predictability

A first approach is presented in Figure 2-38 which shows the comparison between 48 hours forecast of the DWD (Deutscher Wetterdienst) and the measurements at ISET for the global horizontal solar radiation. Partly, it shows a good forecast and, partly, it shows considerable differences. One reason for these differences can be attributed to particularities of the PV system and its location which are not included into the forecast. Beside of these comparison at ISET, [Hartig 2001] also described this approach with similar results. Moreover, he also describes an approach for short-term forecast (1/4 – 1 hour). Figure 2-39 shows the frequency distribution of changes of the global irradiation for ¼ hour and four 1 hour intervals. The database is of one year and only for expected irradiation due to the astronomical situation (7 am – 6 pm).

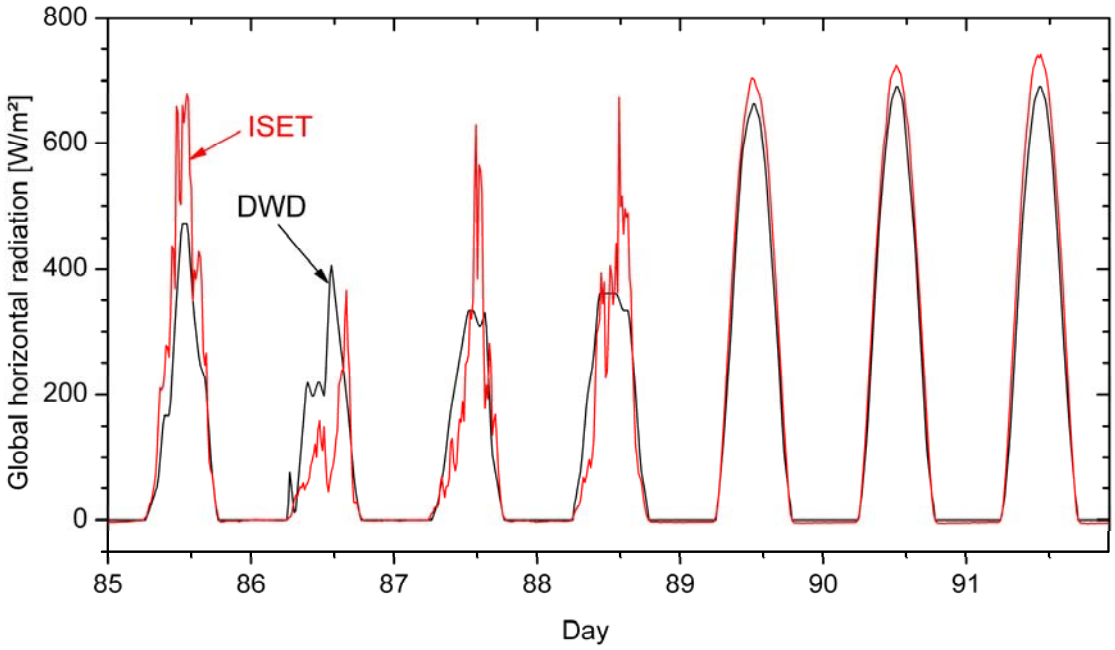


Figure 2-38: Comparison of DWD predictions and ISET measurements for global horizontal solar radiation for seven days in the end of March 2005

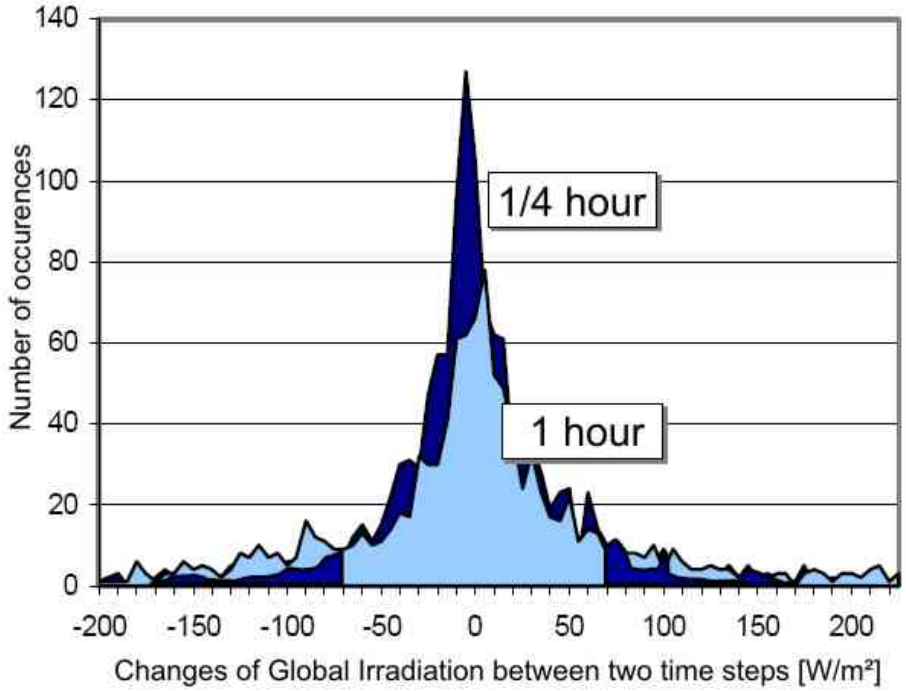


Figure 2-39: Frequency distribution of changes of the global irradiation between two time steps [1/4 and 1 hour] for one year and only for expected irradiation due to the astronomical situation [Hartig 2001]

Furthermore, [Hartig 2001] assumes a short-term prediction approach which results from these little short-term changes. The most probable value at the end of a time interval is the value at the beginning of the time interval. This approach results for the studied database in

a preciseness of even more than 90% for a difference of less than 10% between the global irradiation values of forecast and measurement. Figure 2-40 presents the frequency distribution of this difference for the generated power of a PV system with a forecast time interval of ¼ hour.

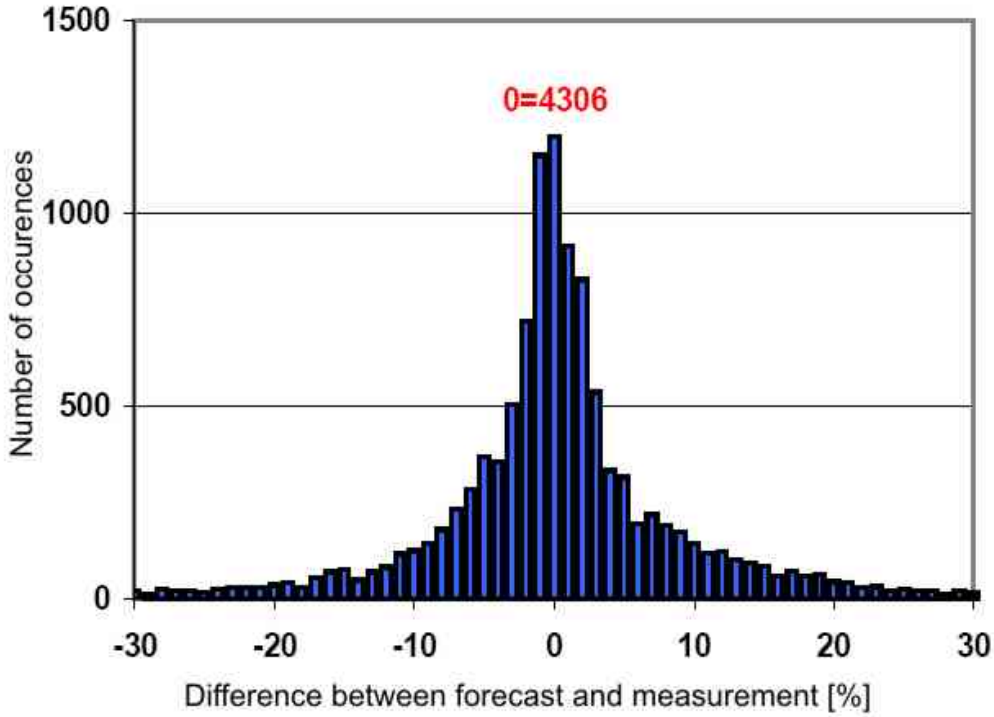


Figure 2-40: Frequency distribution of changes of the differences between forecast and measurement of the PV power generation for one year and only for expected irradiation due to the astronomical situation [Hartig 2001]

[Lorenz et al 2007] present and evaluate a more sophisticated approach to forecast regional PV power production for the next days. With their approach they get an RMSE[2] of 0.13 Wh/Wp for single PV systems. This value is reduced to an RMSE of 0.05 Wh/Wp for an ensemble of the size of Germany. Their forecasting scheme is based on irradiance forecasts up to 3 days ahead provided by the European Center for Medium range Weather Forecasts (ECMWF) with a temporal resolution of 3h hours and a spatial resolution of 25km x 25km. For evaluation of the forecast data they compare the results with a database of about 4500 operating PV systems in Germany.
The power forecast for 11 PV systems resulted in a rRSME (relative RMSE: normalized with mean PV power production of the period) of 49% (absolute RMSE=0.12Wh/Wp) for April with predominant cloudy weather situations and a rRMSE of 30% (absolute RMSE=0.10 Wh/Wp) in July with predominant clear sky weather situations. [Lorenz et al 2007] state that for clear sky days the forecast approach results in minor underestimations and in overcast situations in overestimations. On cloudy days there occur significant deviations as the cloud movement is not modelled correctly. This model preciseness for different weather situations is also depicted in Figure 2-41. The forecast preciseness of irradiation on the horizontal plane is slightly better than the forecast preciseness of irradiation on the tilted plane and finally the power production. These differences result from model deficiencies.
The preciseness is improved by spatial averaging effects as represented by the error

2 $$RMSE = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(x_{forecast,i} - x_{measured,i})^2}$$

correction factor in Figure 2-42. However, Microgrids with their limited spatial extension does not profit as much from this effect. Nevertheless the forecast preciseness increases significantly if all PV systems of one network are taken together instead of only looking at single systems.

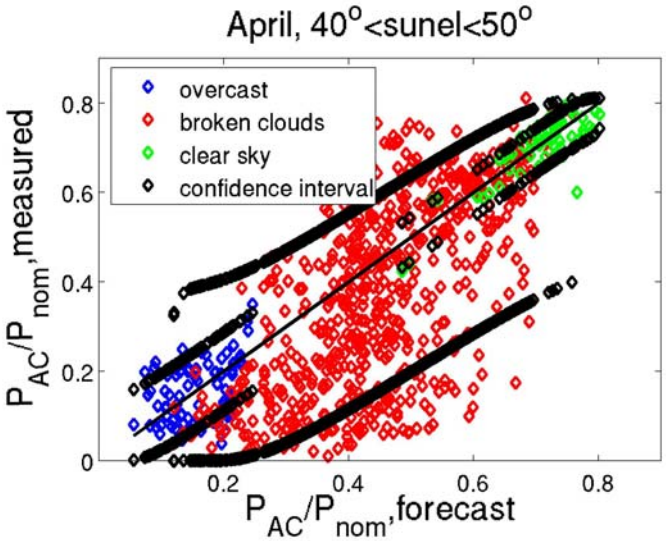


Figure 2-41: Measured power output over predicted power output with confidence intervals for 11 PV systems in Southern Germany [Lorenz et al 2007]

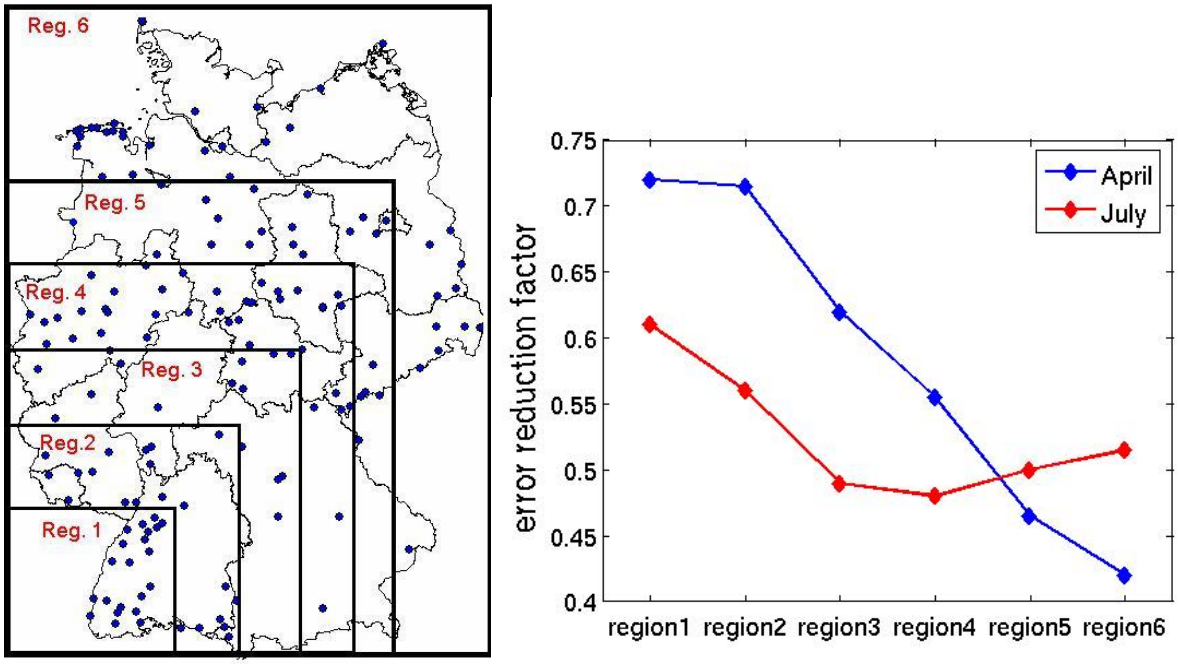


Figure 2-42: Error reduction factor $RMSE_{ensemble}/RMSE_{single}$ for regions with increasing size [Lorenz et al 2007]

2.3.3.3. Active Power Control Capability

A PV system has similar restrictions as a wind energy system with respect to primary energy fluctuations. However, the characteristic of these fluctuations is different because at night there is no power generation and the short-term fluctuations are higher because there is no inertia. Nevertheless, with appropriate forecast, a probabilistic use of active power control is possible, however, limited with respective uncertainties. By changing the DC-link voltage the active power can be controlled. Presently, PV systems use maximum power point (MPP) tracking to operate at the MPP.

2.3.3.4. Reactive Power Control Capability

The reactive power control capability has been analysed in detail in [Braun 2007b]. As all grid-connected PV systems use inverters for grid-coupling, a reactive power control is possible, but limited to an active system (not at night). This time range might be enhanced if the system is not deactivated at night. An active system is able to supply and consume reactive power in a large range, which is only limited by the maximum inverter currents. The system reaches its maximum active power generation only for a short time period if the irradiation is very good and the temperatures are low. Normally, in part-load operation, there is enough capacity for reactive power control. The control of the reactive power of an inverter is very fast. It can change the value within milliseconds.

Assuming a theoretical maximum apparent power for a PV system and an active/reactive control capability as presented in Figure 2-6 allows calculating the possible maximum reactive power production/absorption depending on the actual active power generation according to equation 2-6. With the solar irradiation in Kassel, Germany, a 100 kVA PV inverter which connects a 110 kWp PV generator in 2005 would have had the capability to provide reactive power up to 40 kVAr for more than 99.9% of the year. The performance data is analysed with mean values of 15 minutes. A more detailed overview presents Table 2-11 with inverter dimensioning of 100 kVA and 110 kVA (oversized). The table shows that the availability depends a lot on the dimensioning of the PV inverter. With only 10 kVA more (oversized), additional 20 kVAr are available over 99.9%. This table also shows that it is not possible to guarantee 100% availability of the reactive power supply without oversizing the inverter. However, more than 99.9% is possible.

This comparison with real measurement data and with assumption of the inverter dimensioning show a high potential of reactive power production/absorption which results from the intermittent behaviour of the PV power generation which utilises most of the time not the full potential of the inverter. The exact potential depends on the inverter dimensioning, the PV system characteristics and the irradiation characteristics of the respective plant site. The presented comparison is only an example with certain assumptions which shows the mostly unused reactive power potentials.

Q in kVar	Availability with 100 kVA inverter	Availability with 110 kVA inverter

10	> 99.9%	100%
20	> 99.9%	100%
30	> 99.9%	100%
40	> 99.9%	100%
50	99.9%	> 99.9%
60	99.3%	> 99.9%
70	97.1%	99.8%
80	93.7%	98.3%
90	88.4%	94.7%
100	55.0%	89.1%

Table 2-11: Available Reactive Power Potential of a 110 kWp PV generator in Kassel, Germany in 2005

2.3.3.5. System Reliability

Figure 2-43 displays the technical availability of 116 PV systems in Germany, Switzerland and Italy. It shows that the availability between the older and newer analysed systems has increased from an average of 94.6% to an average of 95.6%. 55% of the newer installations have an availability of more than 99%. Generally, the quality of PV systems and the detailed observation of PV systems increase leading to rising system performances and availabilities of future installations.

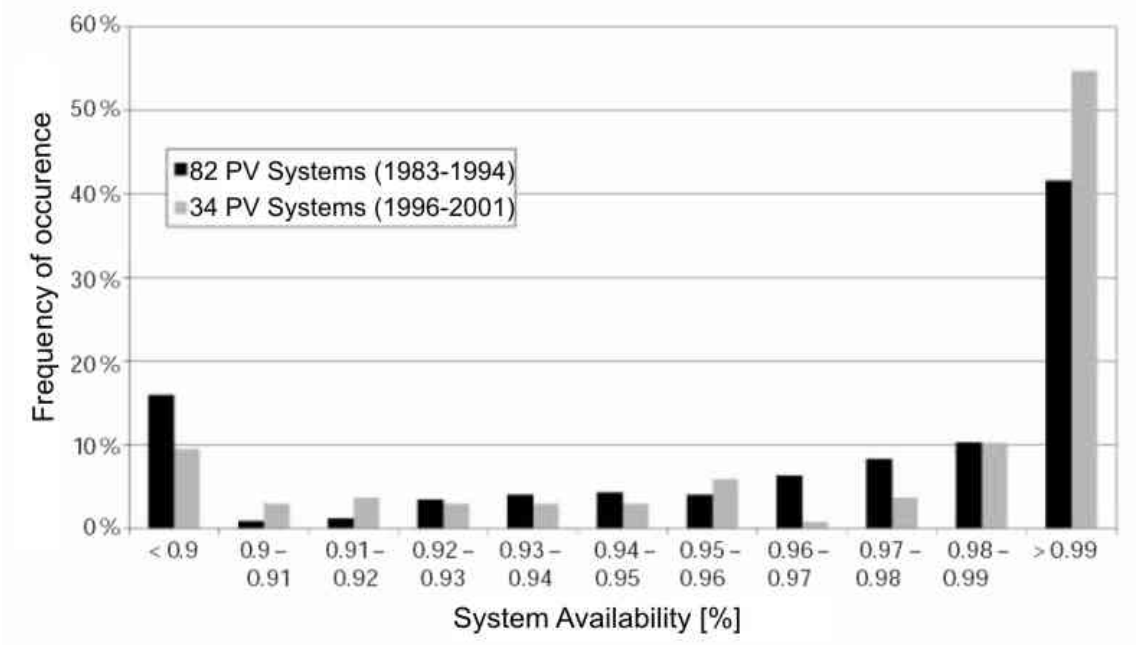


Figure 2-43: Availability of PV systems of different installation periods [Jahn 2003]

2.3.3.6. Capability to Provide Ancillary Services

Table 2-12 summarises the technological capabilities of PV systems to provide ancillary services. Each service is described in more detailed in the following paragraphs.

Ancillary Services	PV
Frequency Control Support	Yes +
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes ++
Improvement of Voltage Quality	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	Yes +

Table 2-12: Technological Capabilities of PV systems

Their active control capability allows PV systems participating in **frequency control support** of all time scales. One limitation is the primary energy fluctuations which limit the availability. Nevertheless, it is possible to say that within a certain probability the power generation would be within a certain bandwidth. The forecast preciseness improves with increasing time horizons and aggregation levels.

This reactive power control capability (Chapter 2.3.3.4) is the basis for good capabilities to provide **voltage control support, congestion management** and **optimisation of grid losses**. But also active power control can be used with secondary priority if the potential reactive power is fully utilised.

The **improvement of voltage quality** can be provided without problems by PV systems due to inverter-coupling. However, this is also limited to an active system as described in Chapter 2.2.3.

Because of the primary energy fluctuations the contribution to energising the grid will not be constant and therewith a challenge to the control of a **black start**. However, generally, black start by PV systems based on self-commutating inverters is possible because they can start without the network due to the inverter's capability of **direct frequency and voltage control** and the available primary energy source on the DC side. Together with the active and reactive power control capabilities **grid-forming** and islanded operation is possible but restricted due to the availability of active power (Chapter 2.3.2.1). According to the weather forecasts only a reduced active power with a security reserve and active power control reserve is available for islanded operation. Generally, black start and islanded operation requires a sophisticated approach to balance generation and demand in a Microgrid. PV can be one element on the supply side which can be included, at least from a technological perspective.

2.3.4. Hydro Power Plants

Hydro power plants have a large range of system sizes. Here, the focus lies on run-of-river power plants which are connected to distribution networks with a size up to some MW. They are classified as small hydro power plants. The majority of them is connected by induction generators to the mains grid, larger ones normally by synchronous generators. Only a few of them use a full inverter for network coupling (mostly with permanent-magnet synchronous generators) [EC 2000]. However, within the scope of this document these inverter-coupled small hydro power plants are analysed.

2.3.4.1. Active Power Availability

Smaller river power plants are classified as intermittent. Consequently, they have similar restrictions of availability compared to wind or PV. Figure 2-44 shows typical water flows of two rivers over one year which show totally different fluctuation characteristics due to their different catchments characteristic. Figure 2-45 and Figure 2-46 show the variability of the water flows in France over different time horizons aggregated over all EDF hydro power plants. While the yearly averaged fluctuations are only +/- 30% of the yearly mean value, the fluctuations inside a year are +130% and –60% of the mean value in the given example. Generally, the active power availability of one considered small hydro power plant is site-, season- and weather-dependent. In Germany, typical full load hours of small hydro power plants are in the range of 3000 to 5000 per year.

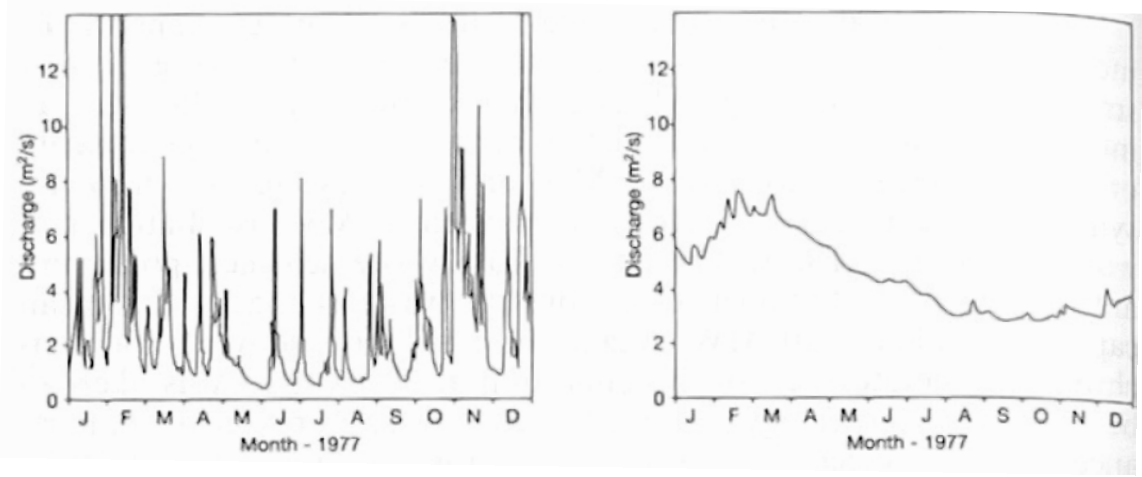


Figure 2-44: Water flow of two different rivers [Jenkins et al 2000]

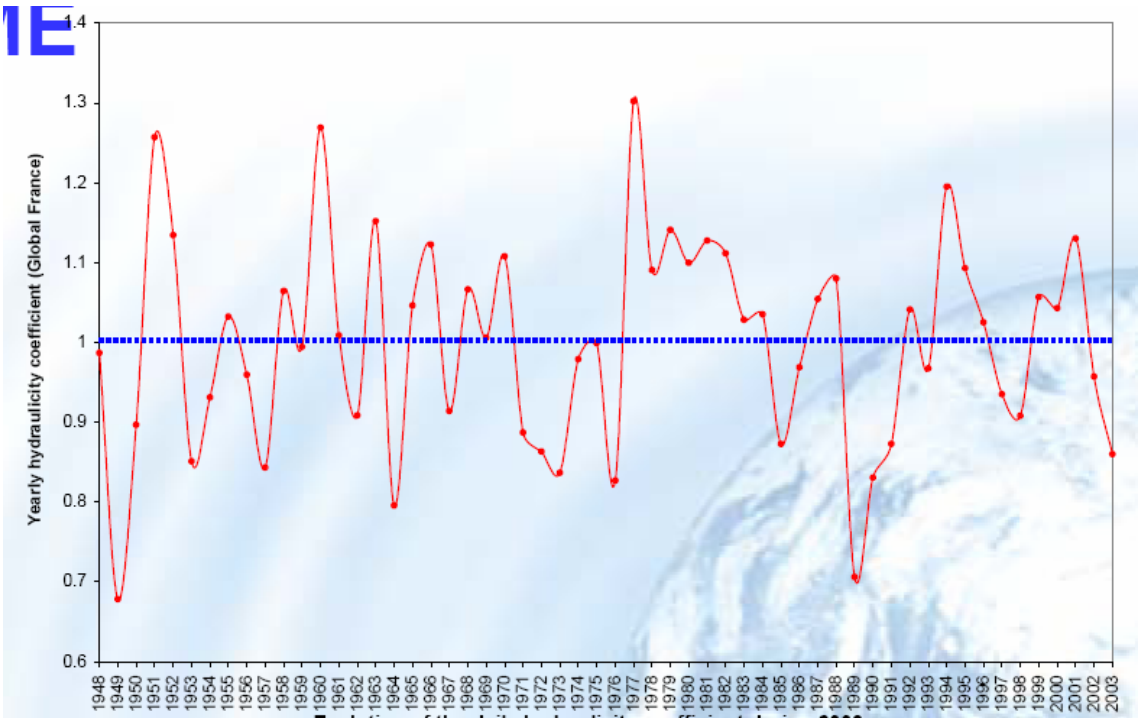


Figure 2-45: Hydraulicity coefficient of all EDF hydro power plants from 1948 to 2003 [Bernard 2004]

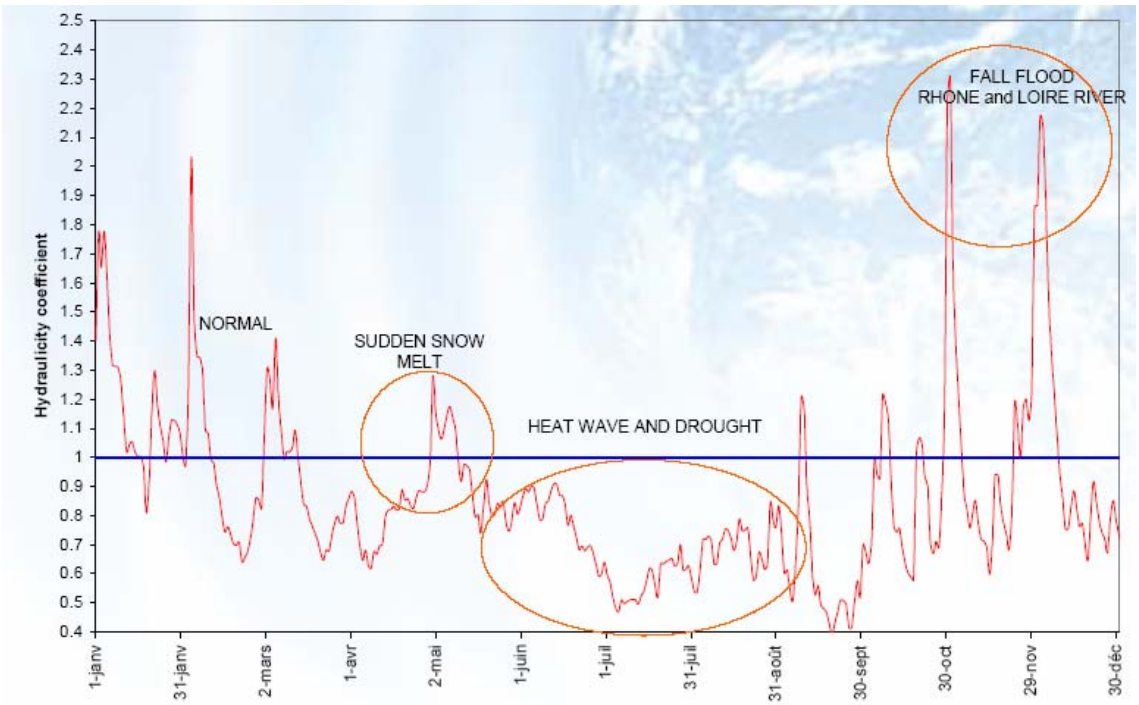


Figure 2-46: Hydraulicity coefficient of all EDF hydro power plants during 2003 [Bernard 2004]

2.3.4.2. Active Power Predictability

Figure 2-47 shows a comparison of the simulation results and the observations of the water flow for two different locations of the Brenta river at Bassano, Italy. This comparison shows the influence of the distance from the source on the forecast model preciseness. The farther the hydro power plant is located from the primary source the more complex the forecast becomes. With increasing complexity the preciseness decreases.

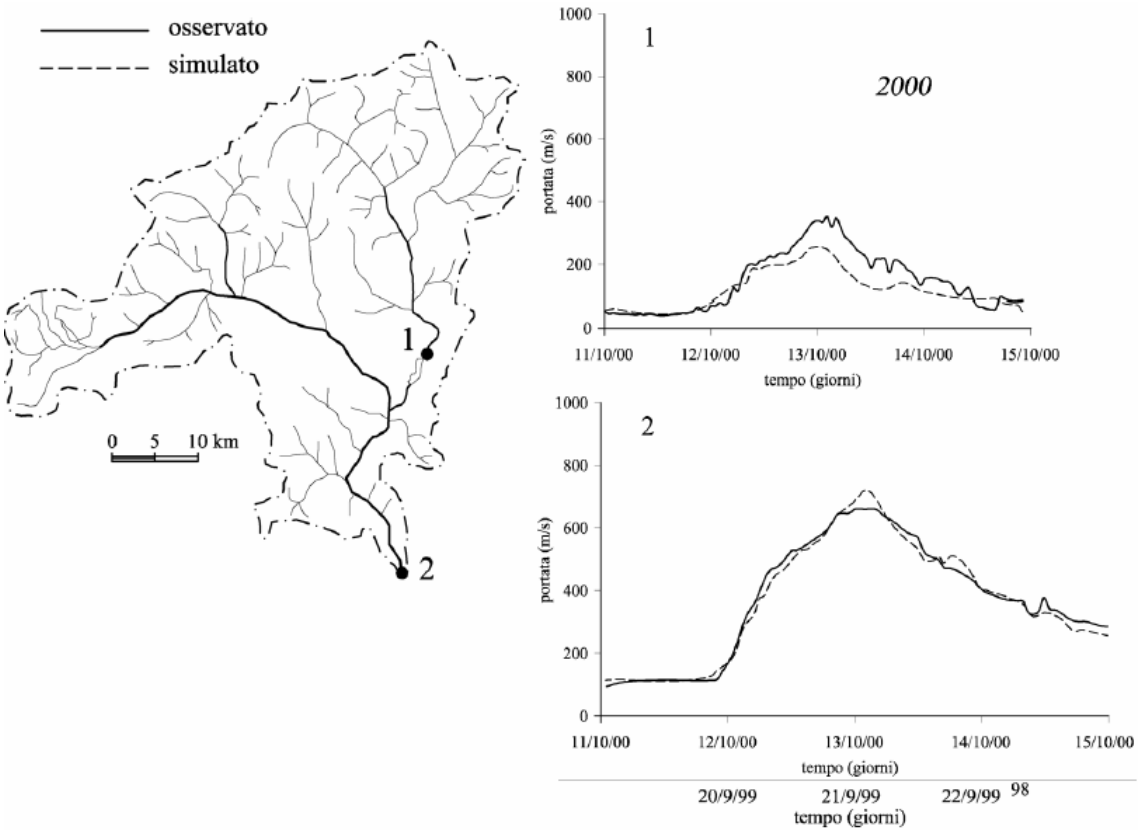


Figure 2-47: Comparison of simulated and observed water flows at to locations (1 and 2) [Ferri et al 2004]

Figure 2-48 shows the day ahead forecast in comparison to the observed water flows of two different Canadian hydro power stations for the years 2003-2004.

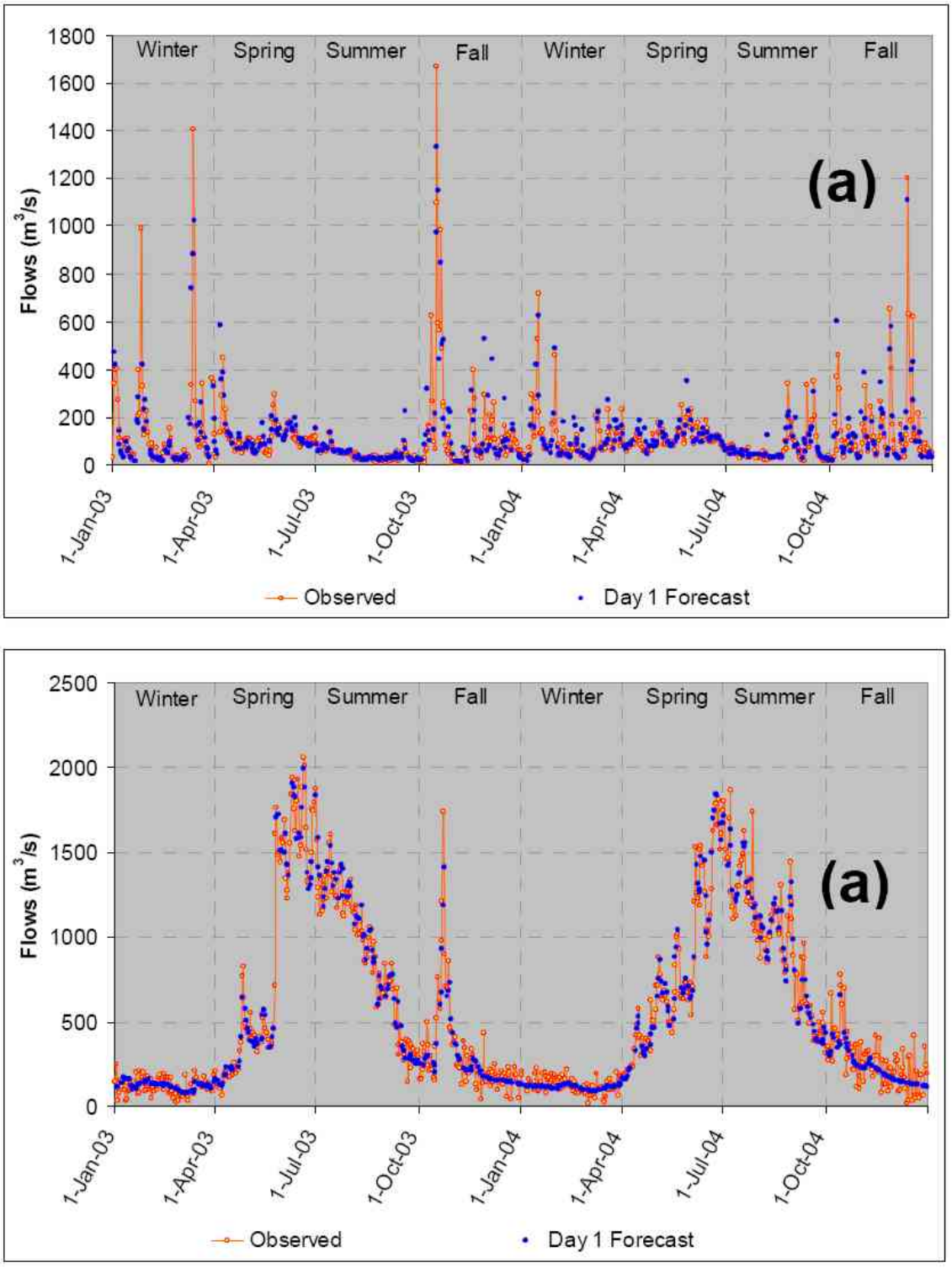


Figure 2-48: Comparison of the observations with the forecast (one and five days ahead) of the water flows for two Canadian hydro power plants Stave and Mica in 2003 and 2004 [Weber et al 2006]

In case of large hydro power plants forecast is often applied while for small hydro power plants rarely. An optimised utilisation within Microgrids demands for forecasts particularly for smaller ones.

2.3.4.3. Active Power Control Capability

A river power plant is technological capable to provide high frequency response by spilling water or reducing the turbines efficiency by turbine blade angle control. Low frequency response requires part-loaded operation which is achieved by reducing the water flow through the water turbine or operating the turbines with a sub-optimal blade angle. A hydro power plant has similar restrictions as a PV system or a WTG with respect to primary energy fluctuations. With appropriate forecast, a probabilistic use of active power control is possible, however, limited with respective uncertainties.

2.3.4.4. Reactive Power Control Capability

Inverter-coupled small hydro power plants would have the capability of reactive power control which can be considered to be similar as for WTGs and PV systems due the intermittency of primary energy supply. The restrictions and dependencies have already been discussed in Chapter 2.3.2.5 for WTGs and Chapter 2.3.3.4 for PV systems and can be transferred analogously to small hydro power plants.

2.3.4.5. System Reliability

The system's reliability is generally more than 98%. The 1-2% unavailability is mostly a result of the revision which often lasts some months but occurs only once after one or two decades. Altogether, hydro power plants are very reliable power generating systems.

2.3.4.6. Capability to Provide Ancillary Services

Table 2-13 summarises the technological capabilities of hydro power plants to provide ancillary services. Each service is described in more detailed in the following paragraphs.

Ancillary Services	Hydro
Frequency Control Support	Yes +
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes ++
Improvement of Voltage Quality	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	Yes +

Table 2-13: Technological Capabilities of inverter-coupled hydro power plants

Due to certain active power control capabilities of a small hydro power plant, **frequency control support** of all time scales is technologically possible. One limitation of active power control is given by the primary energy fluctuations which limit the availability to forecast preciseness. Nevertheless, it is possible to say that within a certain probability the power generation would be within a certain bandwidth.

Fundamental for **voltage control support, congestion management** and **optimisation of grid losses** by inverter-coupled small hydro power plants is their reactive power control capability. But also active power control can be used with secondary priority if the potential reactive power is fully utilised.

The **improvement of voltage quality** can be provided by inverter-coupled hydro power plants as described in Chapter 2.2.3.

Because of the primary energy fluctuations the contribution to energising the grid will not be constant and therewith a challenge to the control of a **black start**. However, generally, black start by small hydro power plants is possible (see also [Delfino et al 1996], [Izena et al 2005], [Tung et al 2006]) because they can start without the network due to the inverter's capability of **direct frequency and voltage control** and the available primary energy source on the generator's side. Together with the active and reactive power control capabilities **grid-forming** and islanded operation is possible but restricted due to the availability of active power (Chapter 2.3.2.1). Generally, black start and islanded operation requires a sophisticated approach to balance generation and demand in a Microgrid. Small hydro power plants can be one element on the supply side which can be included, at least from a technological perspective.

2.3.5. Combined Cooling, Heat and Power Plants

In contrast to the previous analysed DG systems, Combined Cooling, Heat and Power (CCHP) plants comprise a large variety of systems. They are distinguished from WTGs, PV systems and hydro power plants because of their heat conversion process. The heat conversion process allows considering an additional energy flow next to electricity. CCHP plants can be differentiated by systems which do not use the thermal energy flow (condensing plants) and systems which use the heat. The latter can have different priorities for the exploitation of heat and electricity. This priority setting can be relaxed by an included storage device (mostly thermal storage). Within the European project DESIRE, [Sievers et al 2006a] distinguish in principle seven types of CHP plants. Table 2-14 summarises the main differences for these seven types. Rarely, one of the categories is purely fulfilled, mostly it is a mixture.

	Type	Heat demand	Regulation	Heat	Electricity	Purpose/ Incentive
1	Big energy suppliers	Temperature dependent	Electricity oriented	3rd party supply	3rd party supply	Security and costs of Power supply
2 a	Industrial plants	Constant	Heat demand oriented	Own consumption	Own consumption	Less costs of power purchase
2 b	Industrial plants	Constant	Electricity demand oriented	Own consumption	Own consumption	Less costs for peak load price and power purchase
2 c	Small Consumers	Temperature dependent	Heat demand oriented	Own consumption	Own consumption	Less costs of power purchase
3	Energy suppliers	Temperature dependent	Heat demand oriented	3rd party supply	3rd party supply	Low DH-supply and electricity costs
4 a	DH Suppliers	Temperature dependent	Electricity price and heat demand oriented	3rd party supply/ own consumption	Feed-in	Payments for DK Feed-in-Tariff
4 b	Small Consumers	Temperature dependent	Heat demand oriented	Own consumption	Feed-in	Payments for Feed-in-Tariff
4 c	DH Suppliers	Temperature dependent	Electricity price and heat demand oriented	3rd party supply/ own consumption	Feed-in	Spot market

Table 2-14: Different Types of CHP plants (DH = District Heating) [Sievers et al 2006a]

First of all, it has to be decided if the CCHP plant is

- thermal-driven without storage,
- thermal-driven with storage, or
- electricity-driven.

In case of a thermal-driven CCHP plant without storage, the whole thermal process is optimised. Electricity is only a sub-product. It is not possible to change the active power output as this would influence the thermal process.

If the thermal-driven CCHP can be equipped with storage for the thermal processes it becomes possible to vary the active power output within the limitations given by the storage

capacity. The storage could be installed with a large capacity which enlarges the limitations to the requirements for the active power control services of interest. In this situation, the thermal-driven process (from the thermal point of view) can be considered as electricity-driven (from the electrical point of view which we have here).

Finally, an electricity-driven CCHP plant can vary the active power output according to the electricity needs. The thermal output is only a sub-product which has no restrictions to the whole system.

In the analysis at hand we only consider inverter-coupled CCHP plants. This limits the scope as many synchronous generator and induction generator coupled devices will not be considered. Nevertheless, many generator types require an inverter-coupling for appropriate electrical conversion.
Microturbines and fuel cells are always inverter-coupled. The highest efficiency operating speeds of microturbines tend to be quite high, often exceeding 100,000 rpm. The speeds are generally variable over a wide range (i.e., from 50,000 rpm to 120,000 rpm). The microturbine drives a high-frequency generator that may be either synchronous or asynchronous. For all generator types, a three-phase, high frequency voltage, typically in the range of 1 - 3 kHz, will be generated which must be converted with an AC/AC-converter to grid frequency before the generated power becomes usable [Ozpineci;Staunton 2003].
Fuel cells generate direct current from chemical energy. This direct current needs to be converted by a DC/AC-inverter into the correct voltage form to feed into the power network.

Steam turbines, gas turbines, gas engines and piston internal combustion engines are normally SG-coupled. Small systems might also use an IG which is cheaper. Esp. micro-CHP in the size of 1-5 kW, e.g. with sterling engines, often use IG for grid-coupling. However, also these units are sometimes equipped with power electronic converters enhancing their capabilities. Hence, they are also considered herein.

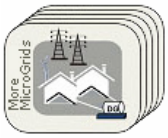
2.3.5.1. Active Power Availability

The fuel of the CHP plant, which could be liquid fossil, gaseous fossil, biomass, biogas, landfill gas etc., is assumed to be available without fluctuations. Consequently, the fuel does not restrict the active power generation. This is a big advantage for the active power control in comparison to intermittent systems (WTG, PV, hydro). With a detailed analysis of single CCHP systems, there might be differences between the availability of the fuel supply which also might restrict active power generation from time to time. This is out of scope of this report as well as solar thermal and geothermal CHP systems which are rarely installed.

An electricity-driven CCHP has an active power availability which only depends on the fuel availability and the system availability, which are both assumed to be very high. In contrast, a thermal-driven CCHP without storage has an active power availability which is directly coupled with the heat demand. If the heat demand varies the active power availability varies as well. This direct coupling can be dampened by heat storage.

Three types of heat demand profiles for one year (typical for Germany) are looked at in [Sievers et al 2006b] (see Figure 2-49):

- Old family houses with low insulation standard (orange line)
- New multi-family houses (green line)
- Constant industrial process heat demand (blue line)



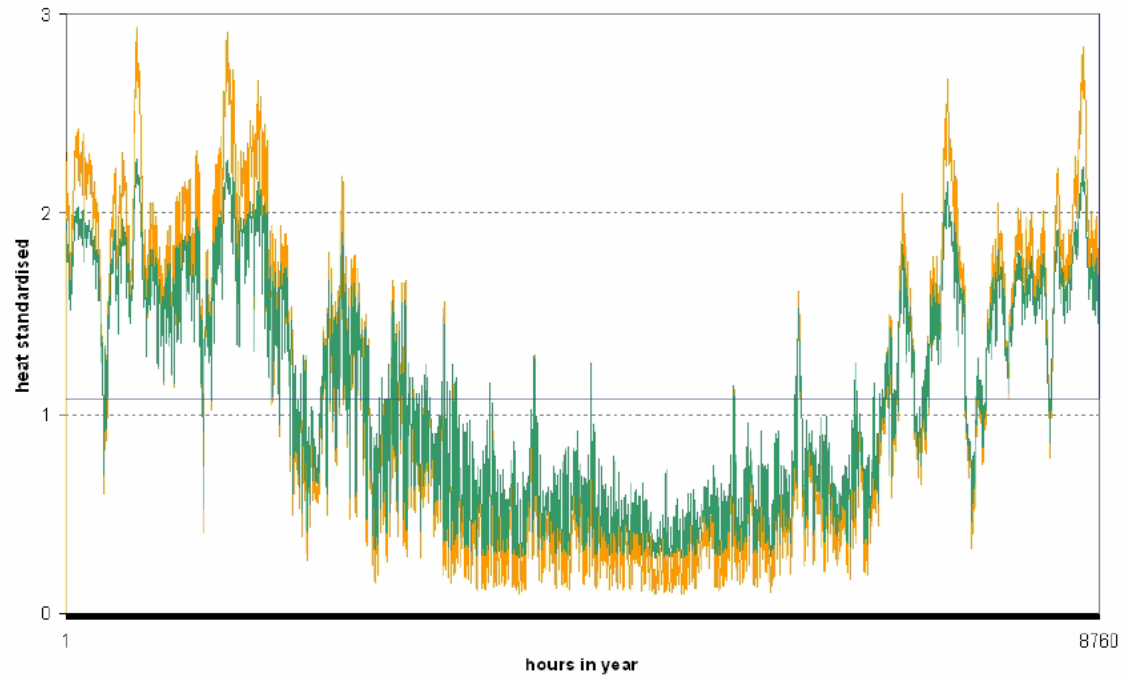


Figure 2-49: Types of heat demand profiles with standardised profiles [Sievers et al 2006b]

[Sievers et al 2006b] analyse small-scale CHP plants up to 2 MW and look at typically used motor-CHP fuelled by Diesel or gas. In Denmark such units are operated for district heat supply, in Spain they are often industrial plants for process heat, and in the United Kingdom and in Germany they are often applied in buildings.

Heat demand profiles of CHP units integrated into buildings are constituted of constant hot water demand and varying space heat demand. Hot water is mainly used at the day and not in the night time. Also here an hourly profile exists, e.g. a peak caused by the shower in the morning. A constant demand in this context means from day to day, because with the use of heat stores this hourly variation does not influence the CHP unit operation. The user's behaviour determines the hot water consumption and the space heat demand, but the last one is mainly determined by the insulation standard and ambient temperature. Both together determine the degree of variation and are expressed by the ratio between constant and varying demand. While the constant heat demand of houses with low insulation standard (250 kWh/m²/a) contributes with 6% to the whole demand, it reaches the order of 50% for passive houses (15 kWh/m²/a). Total heat demand profiles of common applications are mostly dominated by the space heat demand.

An industrial heat demand profile mainly comprises process and space heat demands. Low temperature heat (up to 100 °C mainly for space heat) is very appropriate for heat generation by motor CHP. A higher level up to 400 °C for process heat can be done by CHP units, but process heat above 400 °C can be regarded as inappropriate.

The heat storage size influences considerably the flexibility of the CHP plant. Normally, process heat in industry is constant which allows no active power control capability. Including storage, where possible, allows a very good controllability as the heat demand is constant at rated values in contrast to residential applications where the heat demand varies a lot and restricts the controllability to the respective heat fluctuations which can only be dampened by storage.

2.3.5.2. Active Power Predictability

The predictability is important for thermal-driven CCHP plants as it is helpful to know the possible power generation which is coupled with the heat demand. Therefore, the prediction of the heat demand is necessary. Storage devices enable to improve the heat demand forecast and guarantee a more flexible power generation with increasing storage size. Another distinction on this issue can be done be analysing the predictability of small residential CCHP installations in comparison with large ones for industrial processes or district heating. The former ones are difficult to forecast as it depends very much on the individual consumer's behaviour. Due to dispersion, an aggregation leads to a better predictability as the average effect smoothes the enormous individual fluctuations. In case of district heating, this effect is evident. On the other hand, industrial processes are normally very well predictable and scheduled so that an integration of this kind will enhance the performance of the plant's aggregation.

In case of electricity-driven CCHP plants it can be assumed that active power is available with sufficient fuel capacity and within the plant's reliability.

2.3.5.3. Active Power Control Capability

The active power control capability of electricity-driven CCHP plants is not restricted because of their flexibility based on the consideration of heat as a sub-product. By contrast, thermal-driven CCHP plants do not show any active power control capability as they have to follow exactly the heat demand without flexibility. This heat demand profile might fit to the electricity demand profile leading to a good power generation characteristic but it does not enable a deviation from the heat demand which would be necessary to contribute actively with active power. In between these two extreme situations lies the thermal-driven CCHP plant with storage which can be considered as an optimised CCHP plant with respect to heat generation, power generation and energy efficiency. Depending on the size of the heat storage and the heat demand profile this type of CCHP allows a certain capability of active power control which can be adjusted by the size of the heat storage in the range from thermal-driven heat storage to electricity-driven CCHP plants.

Heat generation is adjusted to accommodate a specific heat demand profile, which is restricting the capability of CHP plants to control active power. In the following [Sievers et al 2006b] lists important heat parameters:

- Yearly heat energy demand (necessary for the correct CHP plant dimensioning)
- Different heat demand profile types (constant in case of industry processes or fluctuating in case of space heating)
- CHP capacity (defined by a certain heat demand peak)
- Storage size (influences very much the independency of the active power control from the heat provision)
- Cogeneration fraction on heat demand (is the ratio between the yearly co-generated heat and the yearly heat energy demand. The remaining demand is covered by peak load boilers.)

[Sievers et al 2006b] show an example of a household with 4 persons, a living area of 180 m², with a heat demand of 150 kWh/m², reference temperature for heating 15 °C, a ratio

between power and heat of 0.5 and heat storage with a storing capacity of the coldest day. The plant is supposed to operate at full load and all of the heat shall be used. Two design concepts are considered: monovalent and bivalent.

The monovalent design has only one heating source (the CHP) combined with heat storage. Figure 2-50 shows that the positive regulation capacity (operation) depends on the ambient temperature and lasts for a certain time frame. The power axis shows the surplus heat capacity that is being stored. Regarding the ambient temperature level being above 15 °C, there is no space heat demand, but only a hot water demand. The time frame in that positive regulating power (operation of the CHP system) is available depends on the actual hot water demand and lasts until the heat storage is filled. Because of the low actual total demand this time is short. Looking at the other extreme, when the ambient temperature reaches the minimum, the CHP unit has to be operated to cover the actual heat demand and heat is not stored. Between the coldest temperature and the reference temperature for starting to heat (15 °C) the CHP plant operating at full load produces more heat than demanded, so that the surplus heat is stored within the heat store. The higher the ambient temperature the more surplus heat has to be stored and the shorter the CHP unit can be operated until the heat accumulator is filled. The missing heat demand restricts the operation. The highest negative regulating power (no operation of the CHP system) can be delivered, when the store is full and the demand is low, so that the discharging process of the storage takes the longest time. At very low temperatures the demand is high and the stored heat lasts for the shortest time.

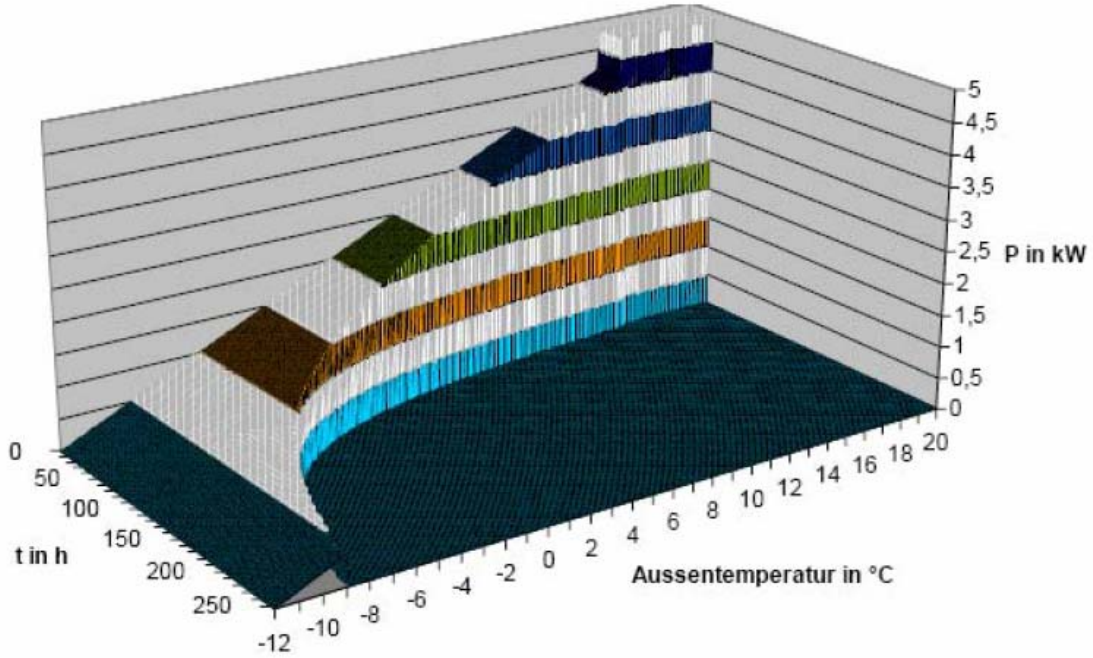


Figure 2-50: Positive regulating power of an monovalent CHP (100% capacity of heat peak) with heat storage [Sievers et al 2006b]

In contrary to the described monovalent system, a bivalent system consists of a CHP, a boiler and also of a heat store. In the given example, the CHP capacity is designed to cover 30% of the heat demand peak.

Figure 2-51 shows that the positive regulation capacity (operation) depends on the ambient temperature and lasts for a certain time period. The power axis shows the surplus heat capacity that is being stored. In this system positive regulating power (operation) is available

without further restrictions as long as the CHP unit produces less heat than actually is consumed. By the assumptions made in this example, the CHP plant covers less than the whole demand at ambient temperatures below 11 °C. In this time, it can be operated all the time. Again positive regulating power is restricted, if the produced heat exceeds the consumed heat and especially, if only the hot water demand has to be covered. The operating time only lasts as long until the store is filled. Negative regulating power (no operation) is available as long as the boiler is able to deliver the whole actual heat demand. In case of a boiler capacity below peak demand a restriction for not operating the CHP unit would occur at high heat demands and depending on the storage capacity.

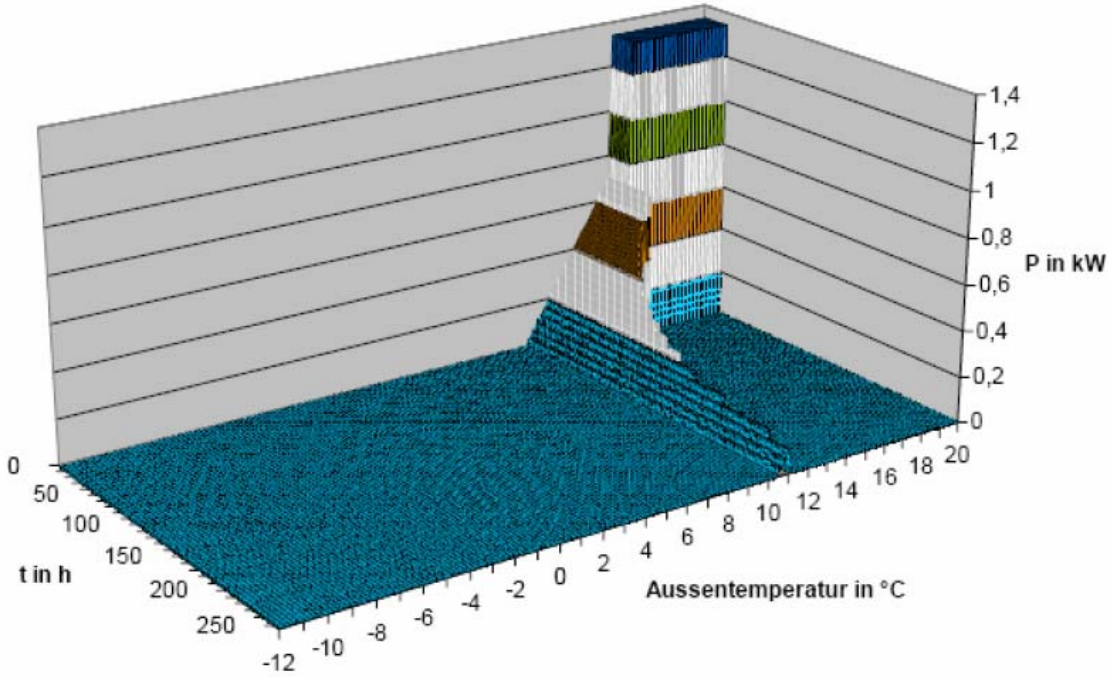


Figure 2-51: Positive regulating power of an bivalent CHP (30% capacity of heat demand peak) with heat storage [Sievers et al 2006b]

Dual heat supply functions (space and water heating) enhance the capability and duration of the micro-CHP unit. Once the units are on line, the output of individual units will be dictated by the thermal time constant of the units. In general, units will run for periods ranging 30 to 60 minutes and switch off depending on maximum temperature settings for water heaters and space heating. After a period of cooling off, the units would restart until the temperature constraints again force them to switch off. The response of micro CHP units will vary seasonally and with time of day. During winter peak demand periods, there would be a high likelihood that many micro-CHP installations would be operating. In summer all space heating will be switched off leaving only water heating. The duration the unit is likely to be able to run will be significantly shorter on a hot summer afternoon than on cold winter morning [ILEX;UMIST 2004].

2.3.5.4. Reactive Power Control Capability

Reactive power control is possible with inverter-coupling as described in Chapter 2.2.2. Different to the fluctuating active power transfer of WTGs, PV systems and hydro power plants, the active power transfer of CCHP plants is normally at rated power. If the inverter's

sizing matches exactly there is no capacity for reactive power supply left. However, a certain oversizing of inverter leads to a 100% secure reactive power control potential if the systems are operated at their rated active power output (see Figure 2-52). An oversizing of the inverter-coupling of 10% for instance allows an additional reactive power control of +/- 46% of the maximum active power generation and an oversizing of 20% even a reactive power control of +/- 66%. These values increase significantly in case of a part-loaded active power generation.

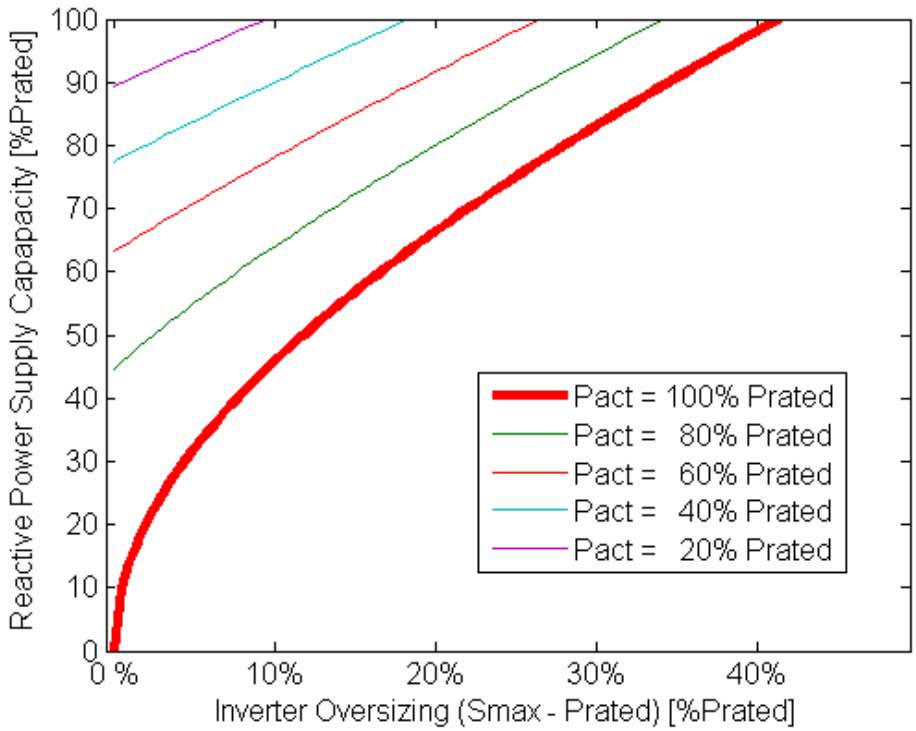


Figure 2-52: Reactive Power Supply Capacity [%Prated] depending on the Inverter Oversizing (Smax – Prated) [%Prated] at different actual Active Power Transfer Pact [%Prated]

2.3.5.5. System Reliability

The system reliability is difficult to assess. Many technologies of CCHP plants are available with very different characteristics. Some are very innovative without reliable data on system reliability, e.g. fuel cells and microturbines. Others need regular maintenance cycles which can be scheduled and, consequently, show a high reliability.

2.3.5.6. Capability to Provide Ancillary Services

Table 2-15 summarises the technological capabilities of inverter-coupled CCHP plants to

provide ancillary services. Each service is described in more detailed in the following paragraphs.

DG System	CCHP	
	(thermal-driven)	(electricity-driven)
Frequency Control Support	No	Yes ++
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes +	Yes ++
Improvement of Voltage Quality	Yes ++	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	No	Yes ++

Table 2-15: Technological Capabilities of inverter-coupled CCHP plants

CCHP plants are only capable to provide **frequency control support** if they operate electricity-driven which allows a control of the active power output. In order to provide low frequency response, the generator would need to run part-loaded. With this assumption, the CCHP plant equipped with an appropriate governor is technologically capable to provide frequency response, spinning reserve and load following. Steam turbines, gas turbines, gas engines, microturbines, sterling engines, piston internal combustion engines and flexible fuel cells are capable to change the energy transformation for the active power control within seconds. Only some types of fuel cells which have a low flexibility of electricity generation might not be fast enough to provide frequency response. The different types of fuel cells are operating at different temperatures: the PEFC (Polymer Electrolyte Fuel Cell) at 60 – 80 °C, the PAFC (Phosphoric Acid Fuel Cell) at 200 °C and the SOFC (Solid Oxide Fuel Cell) at 800 – 1000 °C [Krewitt et al 2004]. Only the PEFC shows capabilities of a highly dynamic operation which would allow frequency response. Also some other types of primary energy conversion technologies might have restrictions of the required dynamics, e.g. biogas plants. A storage medium for biogas with a capacity according to the required flexibility can solve most or all of the limitations.

Due to their reactive power control capability as described in Chapter 2.3.5.4 **voltage control support, congestion management** and **optimisation of grid losses** can be provided effectively by CCHP plants. While electricity-driven CCHP plants allow also active power control as a supplementary option, thermal-driven CCHP plants do not have his capability. Hence, the capacity to provide these ancillary services is lower.

The **improvement of voltage quality** can be provided by inverter-coupled CCHP plants as described in Chapter 2.2.3.

Generally, inverter-coupled CCHP plants have the capability of **direct frequency and voltage control**. Together with the active and reactive power control capabilities **grid-forming** and islanded operation is possible. Only electricity-driven CCHP plants are able to operate islands. Thermal-driven CCHP plants do not have the active power control capability which is necessary for this capability.

In contrast to WTGs, PV systems and hydro power plants, CCHP plants (except fuel cells) have a thermal process which drives the prime mover which then drives the generator. Fuel cells do not use a thermal process for driving a prime mover. They convert chemical energy directly into electrical energy. But mostly, this process needs a certain temperature which is delivered by the heating system. Consequently, all CCHP plants need some kind of storage to start the system without grid connection. This storage can be very small, e.g. to ignite a diesel engine, or very large, e.g. to heat up a high temperature fuel cell. Without such storage, a CCHP plant cannot provide **black start**. Only electricity-driven CCHP plants are able to black start.

Thermal-driven CCHP plants do not have the active power control capability which is necessary for grid-forming because they have to supply the heat properly possibly even during an outage. However, a re-definition of the thermal-driven CCHP plants to electricity-driven ones is possible if it is more important restoring or forming the grid than supplying the heat.

2.4. Results and Conclusions

Presently, most of the distributed generators are blind towards the grid's situation. DGs feed-in as much power as they can to maximise the profit based on active power generation. The only incentive is the feed-in tariff or the relevant power market. With a high penetration of wind power generation, WTGs (as the first type of DGs) are now more and more obliged to provide ancillary services, such as reactive power control and congestion management (by reducing the power generation). Loads are similar blind on the other end of the power flow. The consumer has normally no incentive to change his behaviour to support grid operation.

Compensation effects (aggregation, strong grids etc.) reduce the necessity for an integration of distributed generators into the interconnected network operation. With regard to Microgrids this approach is no longer possible. Microgrids use distributed generators by definition for network operation. Consequently, all technologically possible ancillary services should be used in an economic optimal way. Chapter 2 provides an overview of the technological capabilities of inverter-coupled distributed generators. The summary is presented in Table 2-16. Principally, all types of ancillary services can be provided by inverter-coupled distributed generators. Some limitations exist for thermal-driven CCHP plants which do not have sufficient active power control capability to provide frequency control support and grid-forming. Also the intermittency of WTGs, PV systems and small hydro power plants restricts the availability and the active power control capability to a certain degree. Sophisticated control approaches are capable of making use of these dynamically available ancillary services.

DG System	Storage	WTG PV Hydro	CCHP	
			(thermal-driven)	(electricity-driven)
Frequency Control Support	Yes ++	Yes +	No	Yes ++
Voltage Control Support **Congestion Management** **Optimisation of grid losses**	Yes ++	Yes ++	Yes +	Yes ++
Improvement of Voltage Quality	Yes ++	Yes ++	Yes ++	Yes ++
Grid-Forming: **Direct Voltage Control** **Direct Frequency Control** **Black Start**	Yes ++	Yes +	No	Yes ++

Legend:
No indicates that this is not possible without additional external equipment
Yes indicates that this is possible without additional external equipment
++ indicates very good capabilities
+ indicates good capabilities
- indicates little capabilities
-- indicates very little capabilities

Table 2-16: Technological capabilities of inverter-coupled distributed generators

Two approaches can be distinguished to provide ancillary services: decentralised and centralised. Only one of the two can be implemented or both together. A combination of both approaches allows an optimal use of ancillary services.

The decentralised approach can also be described by terms such as automatic or local. This approach uses local information to control the DER according to implemented set values. The most interesting ancillary services for decentralised control are primary frequency and primary voltage control support, local improvement of voltage quality, and grid-forming. The decentralised approach only has local information which helps to support the grid to stay within the required limitations for voltage, frequency and power quality. A shortcoming of this approach is its inability to optimise the overall grid operation because there is no information on the situation at other grid nodes.

The central approach is necessary for ancillary services which aim to optimise the grid operation. This is achieved by collecting the distributed local information of the network area to understand the state of the network. Then, this information is used to find a better operation strategy which is finally applied by sending new set values to the controllable grid components. ICT equipment has to be installed to enable the various communication flows and calculations.

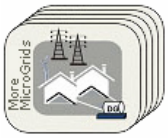
Other enhancements of distributed generators have to be installed to allow providing ancillary services.

Direct voltage and frequency control as well as the **improvement of voltage quality** only require an update of the power electronics control.

Active power control (and therewith also **frequency control support**) might require an enhancement of the DER unit's control. WTGs can use the blade angle control or an adapted maximum power point control to change the efficiency of the energy conversion process. The latter approach can also be applied for PV systems. Hydro power plants can use the turbine's blade angle control or the utilisation factor of the water flow to operate part-loaded and allow controlling active power. CCHP systems (exclusively geothermal and solarthermal systems) need normally some sort of fuel. If the input of this fuel is changed and weighted with the system's efficiency, which might depend on the load factor or internal controls, this allows changing the active power. This approach is applicable for electricity-driven CCHP systems but not for thermal-driven ones. The latter ones need storage devices to decouple the active power generation from the heat generation profile. Also electricity-driven CCHP systems with fuel generation processes (e.g. biogas plants) need to be enhanced by fuel storage if an optimal design of the overall conversion process reaches not the required flexibility. Generally, a re-design of the DER units might be necessary if they are aimed to operate in different part-load situations than they are designed for nowadays. This is necessary because the efficiency of a system depends on the dimensioning of the system's components which is normally optimised for certain operation profiles. If these profiles change a re-dimensioning is necessary for an efficiency optimisation.

In case of full-loaded active power generation the reactive power control reserves might be reduced to zero if the inverter is dimensioned for this rated power. A re-design could be interesting which allows a rated active power and in parallel a certain reactive power. This can be achieved by over-dimensioning (with regard to active power) the inverter. If sufficient reactive power capacity is available only the control function has to be implemented into inverter controls to be able to supply reactive power (and therewith **voltage control support**, **congestion management** and **optimisation of grid losses**).

Grid-forming (islanded operation) is possible with the capability of active and reactive power supply as well as direct voltage and frequency control. In addition, enhancements might be required for **black start** because a DER unit's activation without the support by an existing grid voltage has to be possible. Some systems might get their activation energy by ambient



energy flows (e.g. sun for PV systems, wind for WTGs and water for Hydro power plants). With an appropriate system design these energy flows can be used to provide the activation energy for the system components and finally the whole system. Storage devices have the energy stored to get active and CCHP system might have installed or need to install storage devices to at least ignite the fuel.

In summarizing words: the assessment study of Chapter 2 shows the capacity of inverter-coupled distributed generators with regard to the provision of ancillary services. All necessary ancillary services for a Microgrid's operation can be provided by distributed generators. However, one fundamental restriction is the active power availability (Storage systems, WTGs, PV plants, hydro power plants) and the active power controllability (thermal-driven CCHP plants). This restriction can be reduced and even solved by sophisticated control approaches including forecast and risk measures. A re-design of DER units is necessary for integration into network operation and reasonable for economic optimisation.

3. Performance of Inverter-Coupled Distributed Generators with regard to Fault-Ride-Through Capabilities

3.1. Introduction

The inverter performance with regard to Fault-Ride-Through (FRT) capabilities is analysed in this chapter, focusing on overload performance and short-term storage requirements with regard to typical fault occurrences.

Presently, Wind Turbine Generators (WTG) are used to stabilise the grid in case of faults with their FRT capability. They are not allowed to disconnect during a grid fault. The WTG stays connected and feeds active and reactive power into the grid limited by the maximum current values. After fault clearing, a similar active power (according to wind conditions) is fed-in as before the fault. This prevents a frequency and voltage collapse due to the disconnection of the WTG. The risk of voltage collapse can be reduced by supply of reactive power (in transmission networks) to support the grid's voltage (see Figure 3-1 and Figure 3-2).

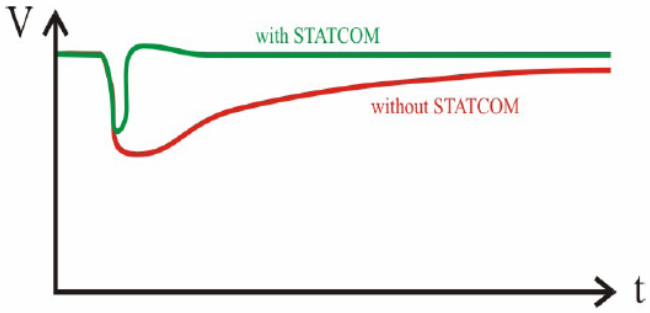


Figure 3-1: Voltage recovery in case of a grid fault with the connection of the Enercon E-70 WTG with "STATCOM inside solution" (green line) and without "STATCOM inside solution" (red line) [Hartge, Fischer 2006]

In case of voltage disturbances to 20% of the rated voltage, the Enercon WTG E-70 shows a short-circuit current of 1.3 times the rated current. The power production is not reduced but the active power output is reduced by producing heat in resistances during the fault. This allows feeding in a very similar amount of active power after the fault as before the fault (cf. Figure 3-2).

Inverter-coupled WTGs can effectively support the grid stability in case of faults using resistances for power balancing at the rotor side of the inverter. [Rouco et al 2006] show a comparison of the dynamic response of WTGs of different grid converter technologies in case of voltage dips. The response of inverter-coupled multipole SGs is limited by the overvoltages in the DC link which can be reduced with a crowbar system. In addition, they do not draw reactive power during the voltage dip.

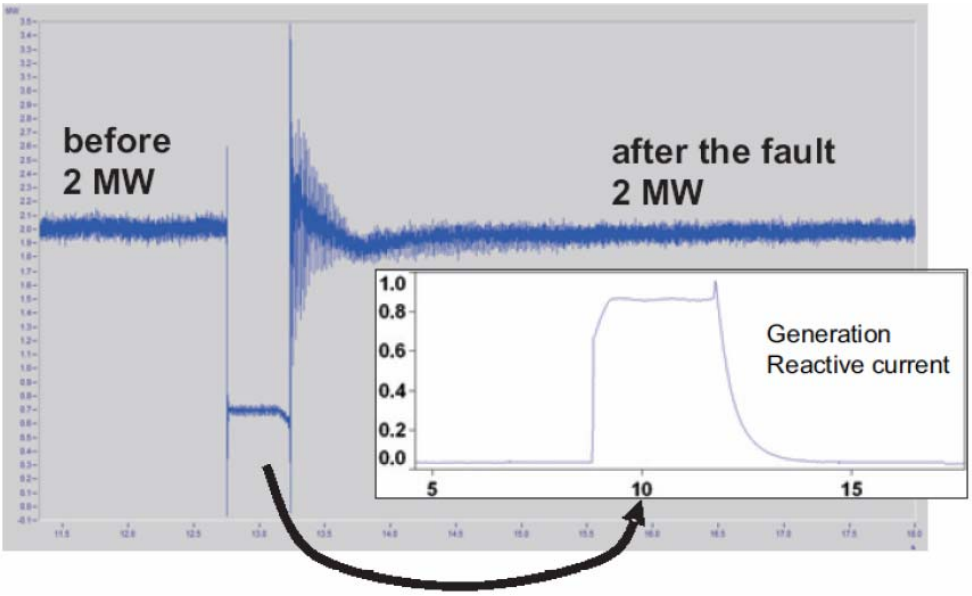


Figure 3-2: Active power (big graph) and reactive power (small graph) supply of the Enercon E-70 WTG with "STATCOM inside solution" [Hartge, Fischer 2006]

Nevertheless, current technologies are based on the premise that power electronics converters may not supply more than its rated current during a fault. Compared to conventional generation (which may inject up to six times the nominal current under fault conditions) the reaction of inverter-based DG under fault conditions is rather unsatisfactory. It is however known that inverters may be overloaded for short periods of time.

The magnitude of this overload depends mostly on the ability of the power electronics to dissipate their losses. Other passive components such as inductors have approximately the same characteristics as generators and thus may provide much higher currents.

This section will study Fault Ride Through capabilities of inverter-based generators from the power electronics perspective. The work is divided in two main sections: Control strategy and thermal simulation.

3.2. Approach

In order to analyse the inverter performance with regard to FRT capabilities the steps depicted in Figure 3-3 have been carried out. It includes the following steps:

- Review of suitable control strategies, which are able to handle symmetrical as well as unsymmetrical fault conditions.
- Integration of the selected control into the basic control of the converter, including the validation on a test network with a single-phase-to-ground fault.
- Determination of steady state and transient currents, for defining the different components' loading.
- Estimation of efficiencies for a set of IGBT modules under normal conditions.
- Determination of overtemperature stress as a result of a given overcurrent.
- Determination of a converter's overcurrent capabilities.

The implementation and validation will be done in a continuous time domain (this is, without including the switching of the inverters) and would represent the following cases:

- 1 kVA,
  one phase inverter connected to the Low Voltage Distribution Network (LVDN).
- 10 kVA,
  three phase inverter (B6 topology) connected to the LVDN.
- 500 kVA,
  three phase inverter (B6 or NPC) connected to the Medium Voltage Distribution Network (MVDN).

From the simulations, the steady state as well as the transient loading of the power electronics components and critical components such as filter inductors is assessed. This has the objective of aiding in the selection of suitable power electronics modules and of providing an input for efficiency and temperature loading analyses.

Several power electronics modules for which thermal response models are available will be selected to simulate the dynamic temperature response and define the maximum safety operation limits (in terms of maximum currents and time). The thermal response analysis is done using empiric simulation models provided by the manufacturer.

For each of the modules, an analytic estimation of the efficiency at normal operation will be done in order to contrast this information to the maximum loading capabilities.

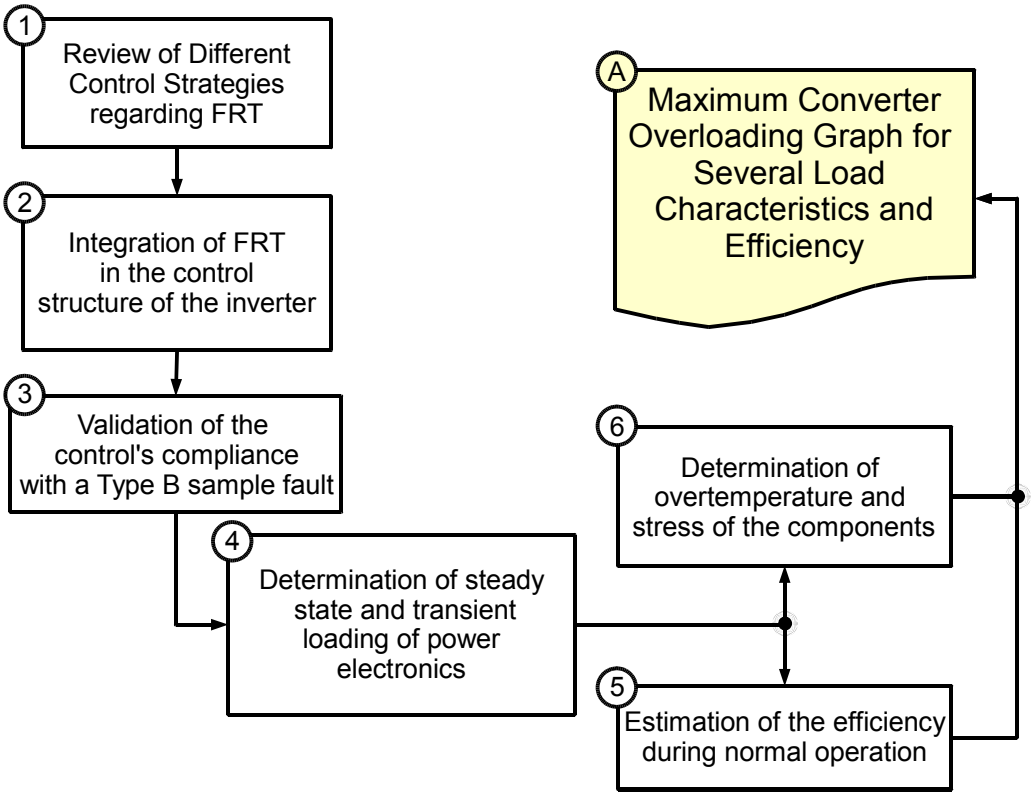


Figure 3-3: Approach Overview

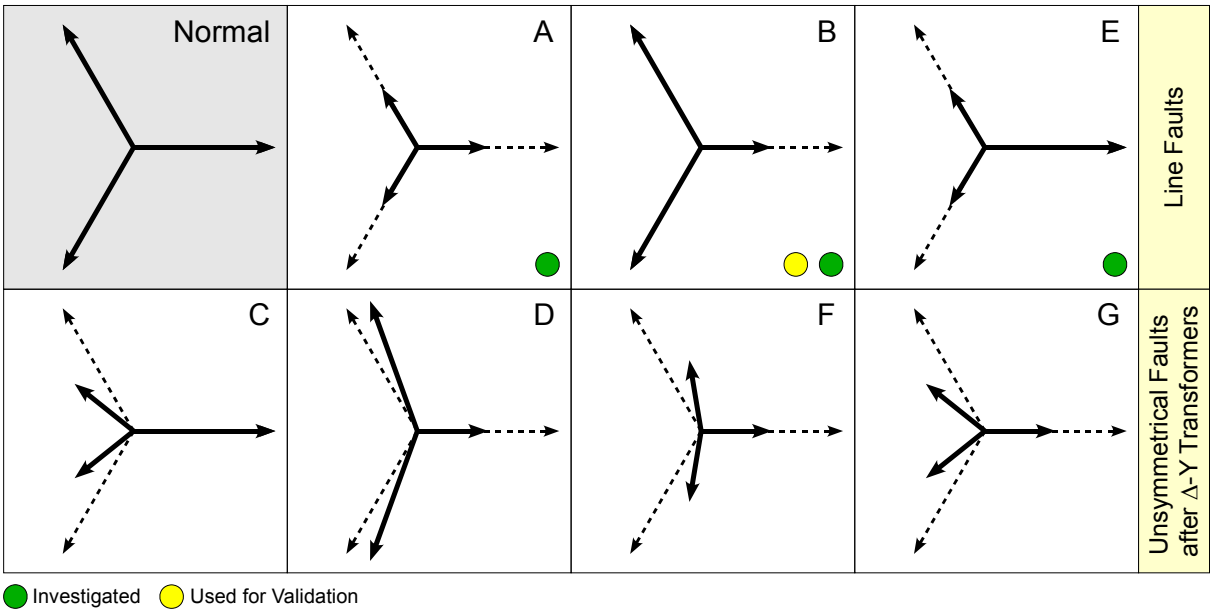


Figure 3-4: Voltage sag characteristics [Pietiläinen, 2005]

3.3. Assumptions and Notation

The following sections present results in a per-unit base unless otherwise noted. The base voltage has been defined to be the Line-to-Neutral voltage (as opposed to the common line-to-line voltage) for simplification purposes. Thus the following per unit conversions have been used:

$$i_{base} = \frac{S_{base}}{nV_{base}} \tag{3-1}$$

$$Z_{base} = \frac{V_{base}^2}{S_{base}} \tag{3-2}$$

Where n will be defined as the number of phases of the system (n = 1 for one-phase systems and n = 3 for three phase systems)

Any conductance or reactance expressed in percent is referred to as the proportion (in percent) of the base impedance.

Active Power is calculated as the sum of all instantaneous powers on all phases.

Reactive Power in three phase systems is calculated from its alpha and beta components as:

$$Q_{gen} = u_\alpha i_\beta - u_\beta i_\alpha \tag{3-3}$$

Please note that an injection of inductive reactive power ($Q_{gen} < 0$) is in fact a generation of inductive reactive power and thus represented as positive in all graphs.

Diagrams and representations of both inverters and network are widely used throughout this work. In order to provide reasonable explanations, several detail levels are used. The most common representation levels are shown in Table 3-1.

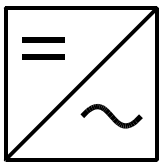
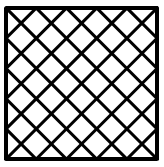
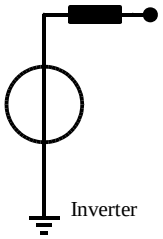
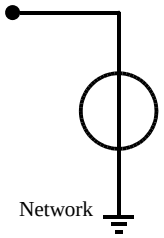
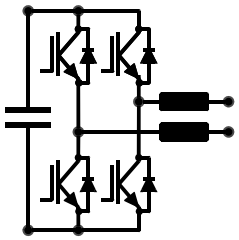
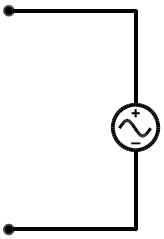
Representation	Uses / Characteristics	Inverter	Network
Conceptual	• Functional representation • Network and inverter topology independent • Network is usually an infinite bus • DG / Storage is implicit		
Averaged	• Inverter is represented by its average model. • Grid is represented with its Thèvenin equivalent. • Analysis independent of topology (for studied topologies) • Useful for phasor analysis.		
Detailed	• Topology Representation. • Grid is represented with its Thèvenin equivalent.		

Table 3-1: Table Name

3.4. Review of Inverter Configurations

In order to validate the control concept and the required capabilities of the power electronics components, the following three cases have been considered. Each of them is intended to test several common nominal powers as well as connection characteristics. Note that this review is intended for information purposes as the final validation of the control strategy is done in a continuous realm.

All the configurations share the same DG source characteristics, which have been chosen to be a Power Source, having the characteristic of a voltage-controlled current source and being the voltage of the DC-Link the input control variable.
The dump load (chopper) is simulated by changes in the power output of the source.

3.4.1. 1 kVA, one phase, connected to the Low-Voltage Distribution Network

This configuration is aimed to represent small-scale inverter-based DGs such as PV inverters connected to the LVDN in one phase. Typically, these devices range from several hundred Watt up to 5 kW (The usual limit for one-phase residential or commercial units).

The topology used for this case is the commonly-used full bridge, which is depicted in Figure 3-5. The bridge is symmetrically switched and the primary control is based on the DC-Link voltage, which setpoint is fixed at 400 V.

Regarding the DC-Link capacitor requirements, the maximum allowed voltage of the DC-Link has been chosen to be 750 V. This maximum specification may be practically achieved with a series connection of two electrolytic capacitors, rated 500 VDC. If required by the application, several sets of capacitors may be connected in parallel. The chosen level of 750 V leaves a 25% overdimensioning factor, to account for ageing effects.

The minimum DC-Link voltage that may be tolerated in fault mode is at least 10% over the rectified peak value of the fault voltage but, in any case, minimum 300 V.

This topology has the following relevant characteristics:

- It is representative of small-power inverters as it is one of the most used configurations.
- The switching strategy is capable of injecting and absorbing reactive power (if within the inverter's power specification).
- Its symmetrical construction (regarding the output inductors) is commonly used in transformerless inverters in order to reduce common-mode disturbances.
- Power fluctuations due to the one phase must be compensated by the filter capacitor anyway. This may help to reduce the need of a bigger capacitor bank.

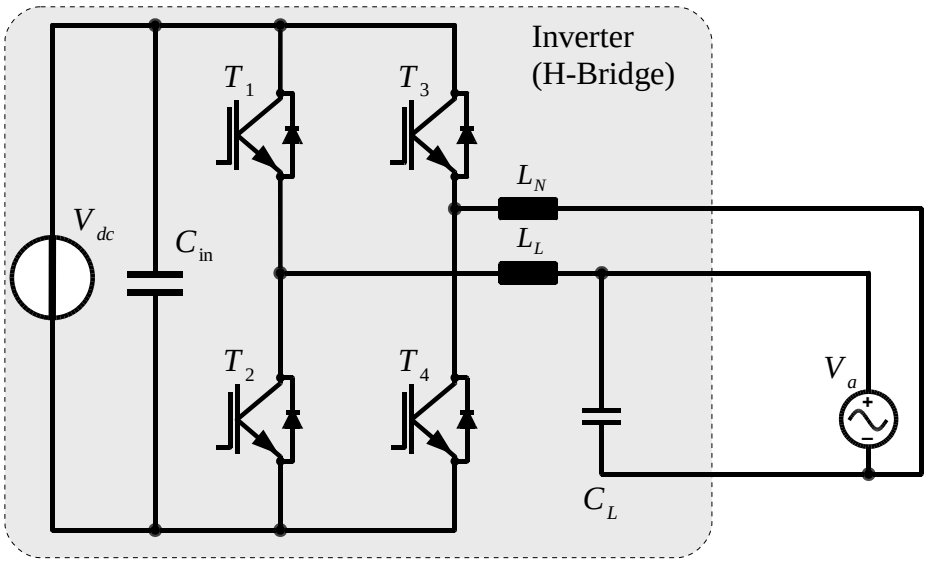


Figure 3-5: 1 kVA single-phase inverter

3.4.2. 10 kVA, three phase, connected to the Low-Voltage Distribution Network

This topology has been chosen to represent medium-scale inverter-based DGs in the range of 5 – 85 kVA connected to the LVDN through three phases (range based on the largest typical IEC 309 connector's rating of 125 A).

This topology, called a B6-Bridge, has three active legs, and even though a neutral line may or may not be connected, can only inject current in these three legs, making it impossible to inject compensation currents through the Neutral (It may inject high frequency currents at the switching frequency, however).

The topology represents a Voltage Source Inverter, being effectively a switching voltage source inductively coupled to the grid. Due to the properties of symmetrical three-phase systems, this topology has little DC-Link Capacity requirements, ranging normally in the order around 100 μF as opposed to the usual 2 mF required by one-phase inverters in the 3 - 3.5 kW range. Equation (3-8) shows one calculation procedure considering power source characteristics.

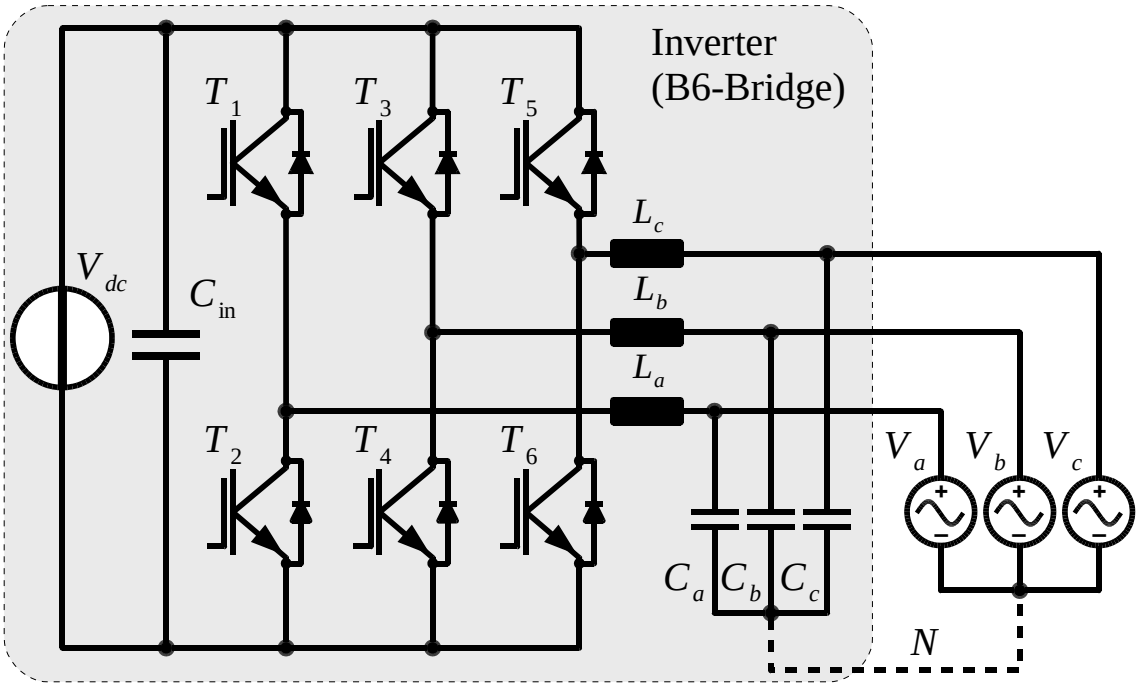


Figure 3-6: 10 kVA three-phase inverter (B6 configuration)

This topology has the following relevant characteristics:

- It is representative of medium-power inverters and it is one of the most used configurations in this power class.
- The switching strategy is capable of injecting and absorbing reactive power (if within the inverter's power specification).

3.4.3. 500 kVA, three phase, connected to the Medium-Voltage Distribution Network

This power class of inverters are not connected to the low voltage distribution network but to the medium voltage network (typically 10-30kV). Because the higher voltage level requires power electronics components with higher blocking voltage capability, a number of topologies become now worth investigation. However, for the purpose of this deliverable, only one topology will be analyzed.

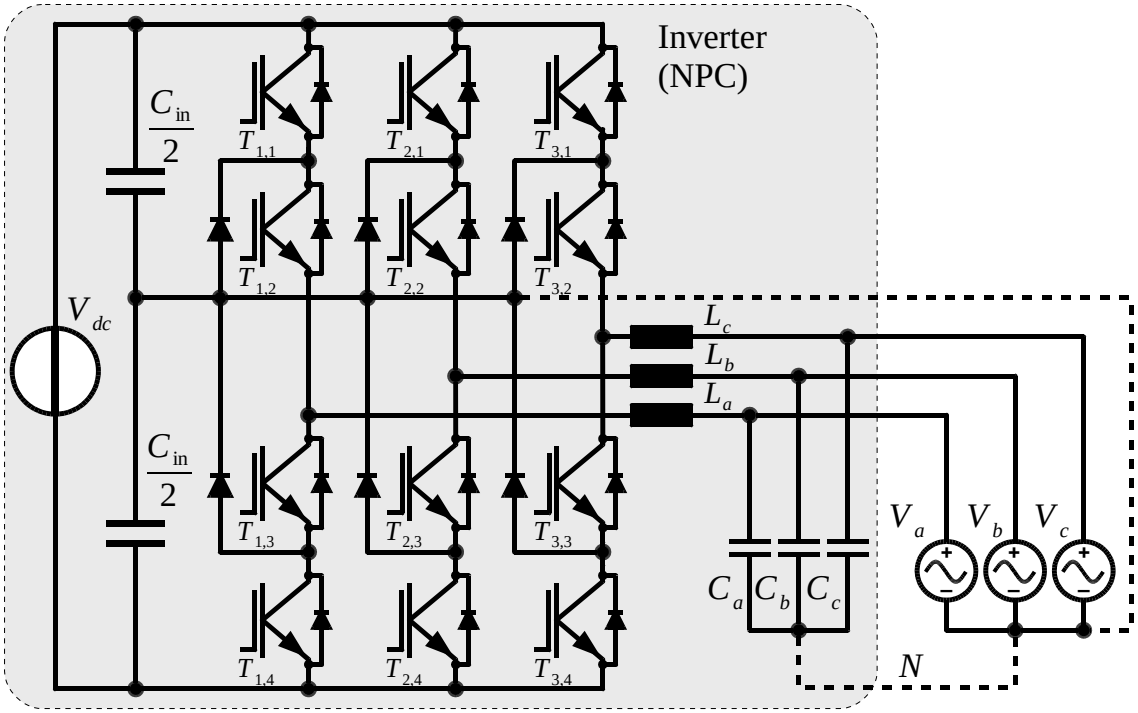


Figure 3-7: 500 kVA three-phase inverter (NPC configuration)

The Neutral Point Clamped (NPC) inverter consists of 12 switching devices (with their corresponding reverse diodes) and six additional clamping diodes.

The inverter is classified as a multilevel topology as the inverter can actively generate three voltage levels: +DC-Link, 0V and –DC-Link. It has also three active legs (even though the Neutral must be connected) and thus cannot generate compensation currents in the Neutral.

Normally DG connected to Medium Voltage Networks, includes a LV/MV transformer. This will be considered in grid simulations as it may shift grid voltages but for sake of simplicity is not included in the analysis of the topology.

3.5. Review of Suitable Control Strategies for FRT

Inverter control is more flexible than other machines used for power production such as synchronous or asynchronous machines. This is due to the fact that each inverter line can be controlled in a *quasi* independent manner instead of being constrained by the mechanical properties of the machine.

This property gives the inverter several degrees of freedom that synchronous and asynchronous generators do not have. They can control the phase, magnitude and harmonic contents of each of its legs voltages and thus generate a wider range of current characteristics.

It is convenient to note that this report will focus on the most common branch of inverters: The Voltage Source Inverter (VSI), while leaving out Current Source and Z Source Inverters.

Three-phase VSIs can be represented by three independent voltage sources coupled to the grid through a coupling impedance $jX_{coupling}$. It can be seen that if desired, an inverter could react to grid faults as a synchronous machine but would leave out the whole potential benefits that the inverter could bring. This will be discussed further on.

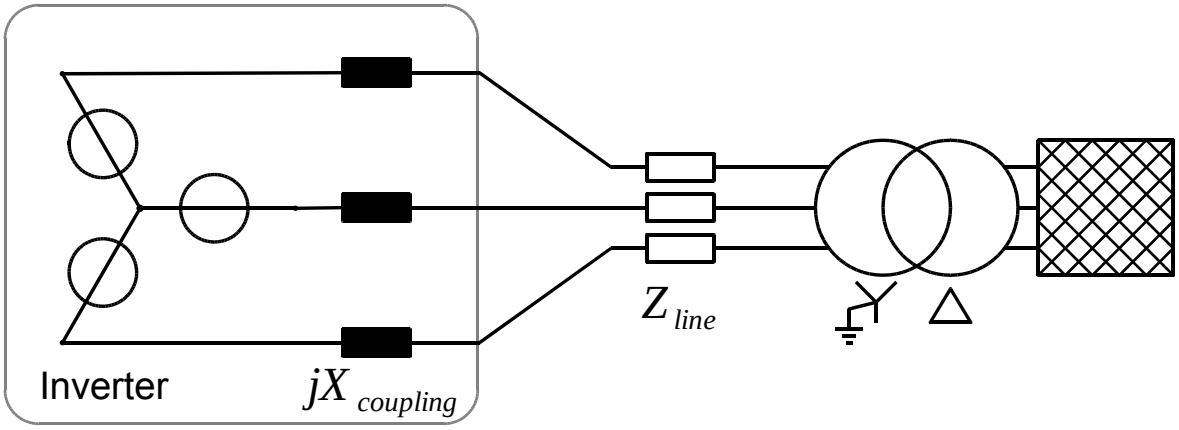


Figure 3-8: Equivalent Diagram of a three-phase inverter connected to a 4-wire Wye Distribution Network

Due to the extended degrees of freedom of inverters, the FRT problem becomes especially interesting in terms of control design. The conflict of interests between power quality, grid backup, economics and inverter overloading makes the optimization process rather demanding. This section evaluates three different control strategies and analyzes the different advantages and disadvantages of each one. It will focus on three-phase inverters with three active legs only, since these are the most common type of inverters. One-phase FRT control will be discussed within the relevant Test Case.

3.5.1. Problem Description

There are four main interests that have to be considered in FRT control design. These are presented below.

- **Power quality.** Even in fault conditions, the generators must help improving the grid quality or at least comply with the power quality requirements. This applies mostly to the Total Harmonic Distortion but also to voltage (and maybe frequency) backup.

- **Grid Support.** The generator must try to help the grid in recovering from the fault. This is, in fact, in most cases the primary aim of FRT-capable generators and one of its most important priorities.

- **Economics.** The generator should try to maintain its nominal output power to prevent or at least minimize the use of choppers and lose valuable energy. However overdimensioning requirements also impact the economic factor as they may impact the efficiency of the inverter and the initial investment. Reliability has a considerable impact in this field as well.

- **Inverter Overloading.** The overloading of the inverter should be maintained to a minimum level, although it is clear that some overloading may be necessary, it should be so that it has little or no impact on the reliability.

For the evaluation of each control strategy, the conditions presented in Figure 3-9 are applied. These represent a worst case scenario if the short circuit power at the point of connection is assumed to be much greater than the nominal power of the generator.

For this analysis the three basic fault scenarios (Type A, Type B and Type E) will be analysed. Z_{fault} is chosen in such a way that the residual voltage at the Point of Connection is varied from 100% U_n down to 2% U_n.

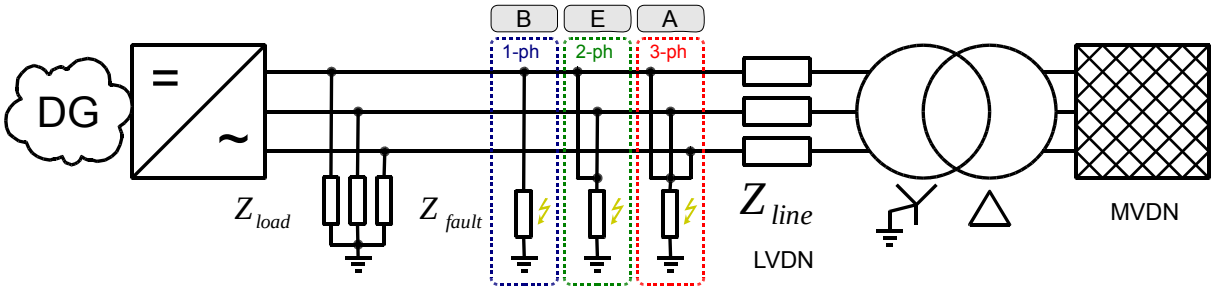


Figure 3-9: Assumed Fault Network with the three fault cases to be analysed.

Please note that main purpose of this analysis is to evaluate the characteristics of the control strategies at different voltage and asymmetry levels and not the effect of each control strategy in the grid. Therefore the faults are considered at the terminals of the inverter connected to a semi-infinite bus.

The different control strategies to be evaluated are shown below:

1. Synchronous Machine Emulation
2. Delta Instantaneous Active-Reactive Control (IARC)

3. Positive-Negative Sequence Compensation

3.5.2. The reference system

For the sake of clarity and space, the common set of conditions, against which, the evaluation is made is presented in this section.

Figure 3-10 shows the reference three-phase system used when evaluating the control under *nominal* operating conditions. The set of voltages are, as in ideal systems, of magnitude 1 pu (RMS) and each phase lags the previous one in exactly 120°.

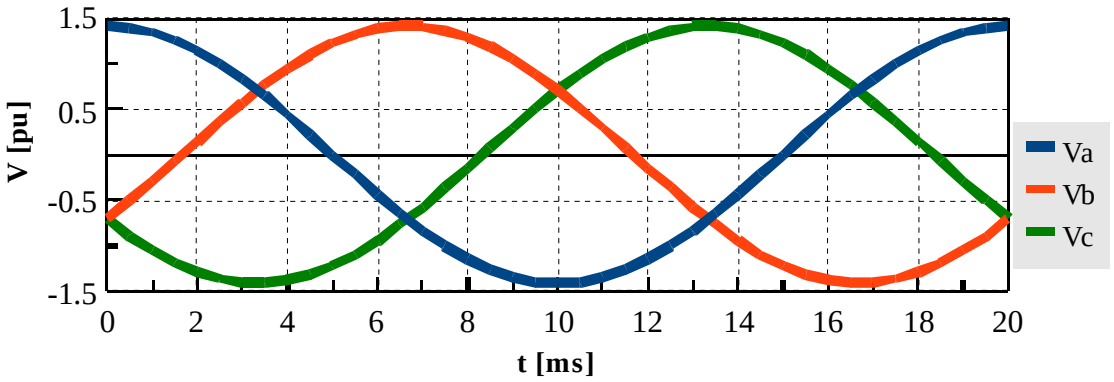


Figure 3-10: Reference voltage set for normal conditions

On the other hand, the set of waveforms shown in Figure 3-11 correspond to conditions as seen in type A, B and E faults. In these cases the magnitudes are affected by the fault but the phase angle between them is kept unchanged. As stated in previous sections, only these types of faults will be reviewed.

The voltage set for fault conditions consider that each of the faulted phases has a residual voltage U_r of 20%U_N. This voltage level has been chosen to ensure a clear representation of the results[3] .

Note that main purpose of this analysis is to evaluate the characteristics of the control strategies at different voltage and asymmetry levels and not the effect of each control strategy in the grid. Therefore the faults are considered at the terminals of the inverter connected to a infinite bus.

[3] Moreover, it represents the maximum voltage dip that a DG must withstand before disconnecting in some countries' Grid codes.

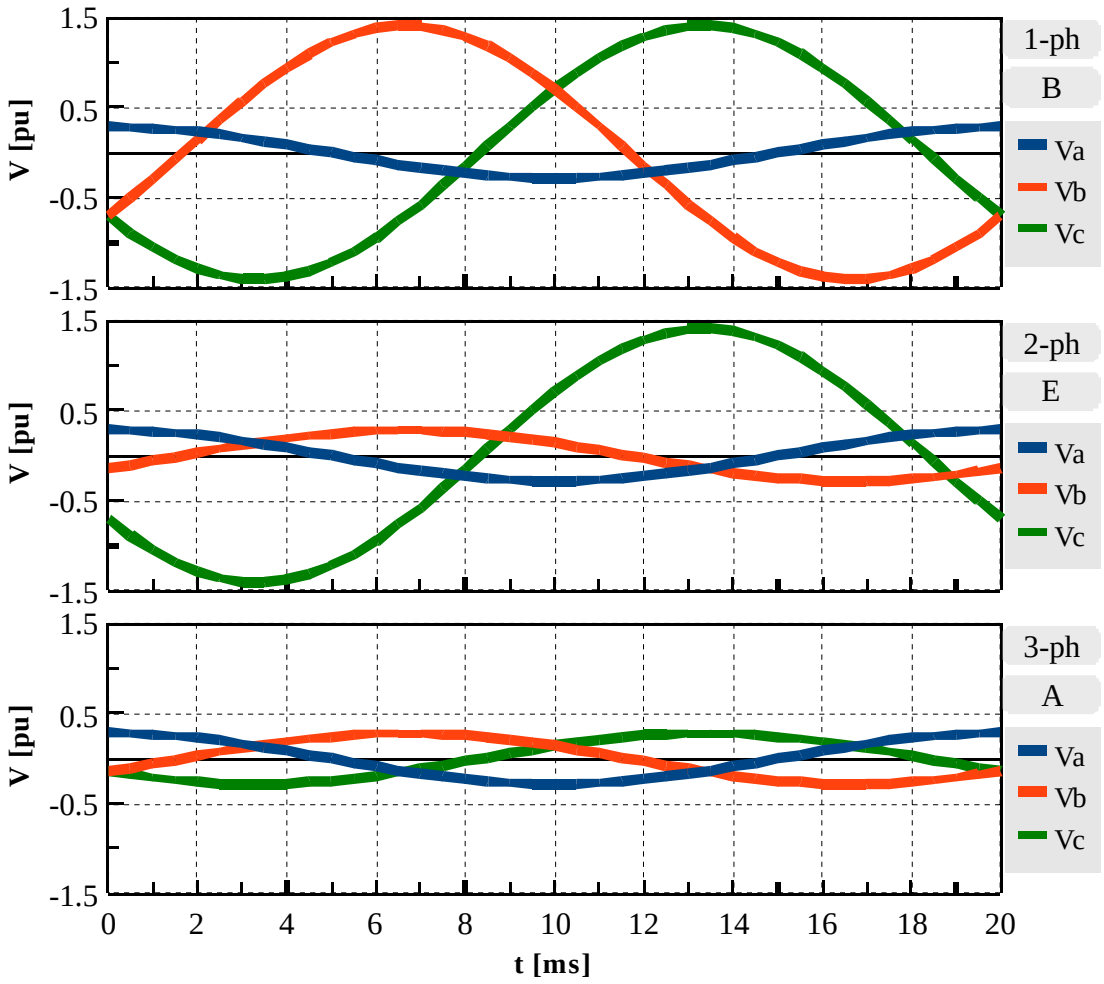


Figure 3-11: Reference voltage set for fault conditions (Types A, B and E)

3.5.3. Synchronous Machine Emulation

3.5.3.1. Concept

Several literature such as [Engler, 2001] and [Beck, 2007] have stated the idea of using an inverter as a virtual synchronous machine. This concept comprises much more than just the response under fault conditions but also under normal conditions. The concept presented herein is, however, much more restrictive and focuses on a very simple (yet quite used) linear model of the synchronous machine under fault conditions as explained by [Grainger, 1994].

The main operation principle of this strategy is to emulate the operation of a synchronous generator connected in Delta (or connected through a Star-Delta transformer). Figure 3-12 shows the equivalent circuit of a synchronous machine used for fault analysis. Note that since the inverter has no active neutral, the ground reactance x_g'' is not present.

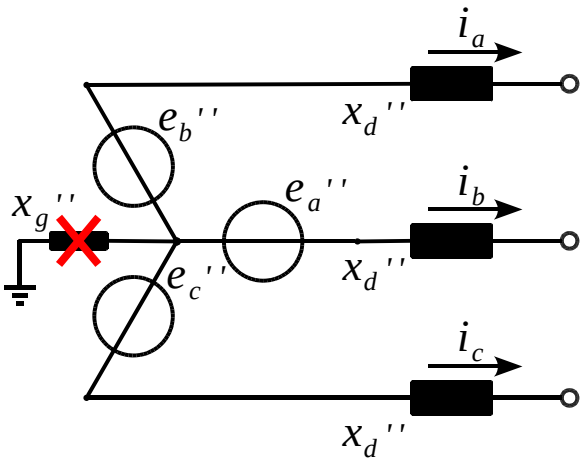


Figure 3-12: Equivalent Model of a Delta-connected synchronous generator at the moment when a failure occurs.

Figure 3-12 shows each of the pre-fault Electromagnetic Force (EMF) (e_a'', e_b'', e_c'') and the sub-transient reactances of the machine (x_d'') that are used for the calculation of the short circuit currents.

In this calculation, it will be considered that the reaction time of the field excitation control of the machine is much larger than the applicability of the subtransient reactance (typically 6 cycles) and that the flywheel of the generator is enough to prevent a lose of synchronism [Loehlein, 2006].

This control strategy thus emulates the reaction of the synchronous machine to a grid fault, more or less independent to the field control and the governor.

Since there is no neutral, the path for zero-sequence currents is of infinite impedance and thus the zero-component of the residual voltage seen by the inverter does not bring any contribution to the short-circuit current. Under this assumption any line current can be calculated based on [Grainger, 1994] as:

$$i_j = \frac{e_j'' - (U_{1,j} + U_{2,j})}{jx_d''} \qquad (3\text{-}4)$$

Where i_j is the fault current in line j (j = a, b, c), e_j'' is the pre-fault EMF of line j, $U_{1,j}$ and $U_{2,j}$ are respectively the positive and negative sequence voltage phasor of line *j*.

It can be seen that the short circuit current is dependent on the pre-fault EMF of the machine and thus on the output power just before the fault occurs. Nevertheless, this influence is relatively small.

3.5.3.2. Analysis of Simulation

The following results show an inverter that emulates a delta-connected synchronous machine having a subtransient reactance of 10%[4]. Figure 3-13 shows the pre fault state of the inverter with nominal output power (1 pu) and no reactive power. As expected in a perfectly symmetrical system, neither active nor reactive power fluctuations are present. Because of the convenience of having no power fluctuations the DC-Link capacitor requirements are usually very low. Experience shows that capacitor conductance values in the order of 5.5% are sufficient for normal operation cases.

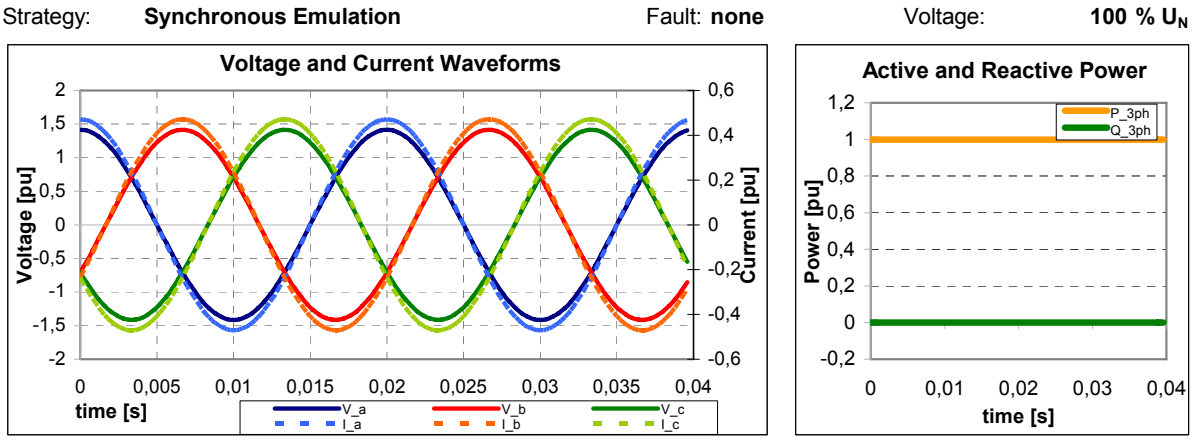


Figure 3-13: Pre-fault Voltage, Current and Power Waveforms

Figure 3-14, Figure 3-15 and Figure 3-16 show the current and power waveforms for the three types of faults. All cases have a residual voltage of around 21%.

It can be observed that active and reactive power fluctuations increase and can reach amplitudes of up to four times the nominal power in the case of active power and up to five times the nominal power in the case of the reactive power. The power output oscillations result not only from the asymmetry of the grid but also from the inability of supplying zero sequence currents. Figure 3-16 shows that for symmetrical faults the fluctuations in P and Q are minimal.

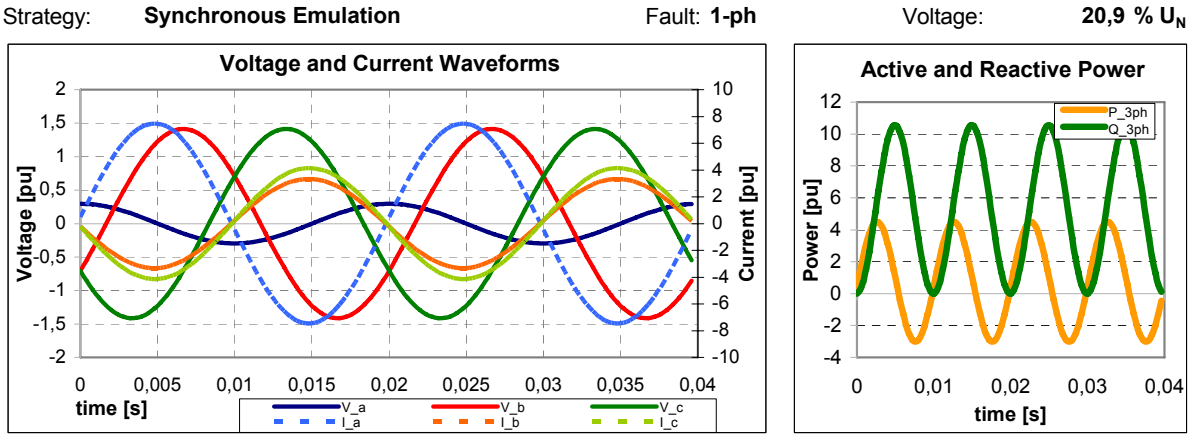


Figure 3-14: Current and Power Waveforms for a single phase-to-ground fault

[4] Typical x_d" values are 9-17% as cited by several sources including [Loehlein, 2006]

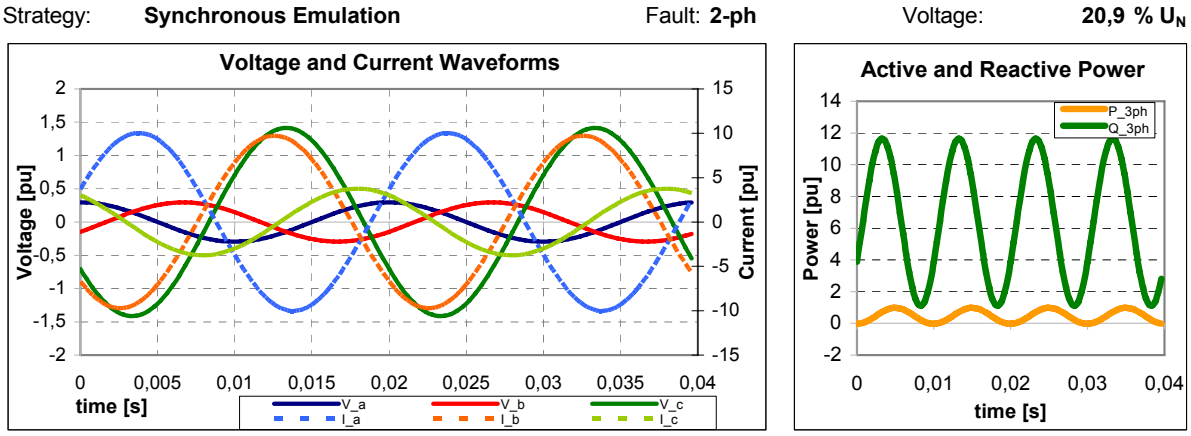


Figure 3-15: Current and Power Waveforms for a double phase-to-ground fault

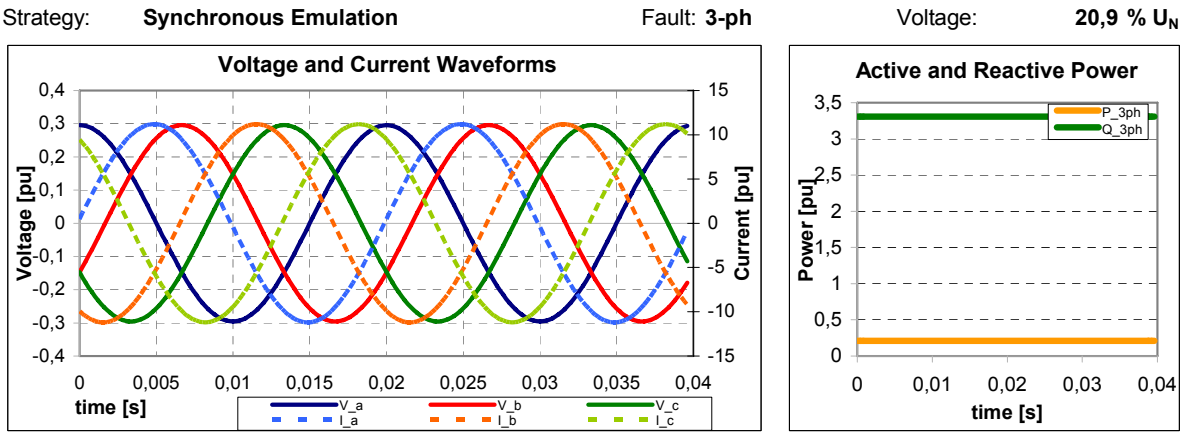


Figure 3-16: Current and Power Waveforms for a three phase-to-ground fault

As seen in the above plots, a fault applied to this control technique produces overcurrents that could reach up to 30 times the nominal current for the proposed example. Please note the different axis scaling of both, the current and the power. The overcurrent depends on x_d'' which value can be changed to reduce the overcurrent value but that would also impact in the grid-support capability of the converter.

Figure 3-17 shows the overloading characteristic of the analyzed topology. It can be seen that the factor I/I_N increases in an almost linear manner with decreasing remaining voltage.

Strategy: **Synchronous Emulation**

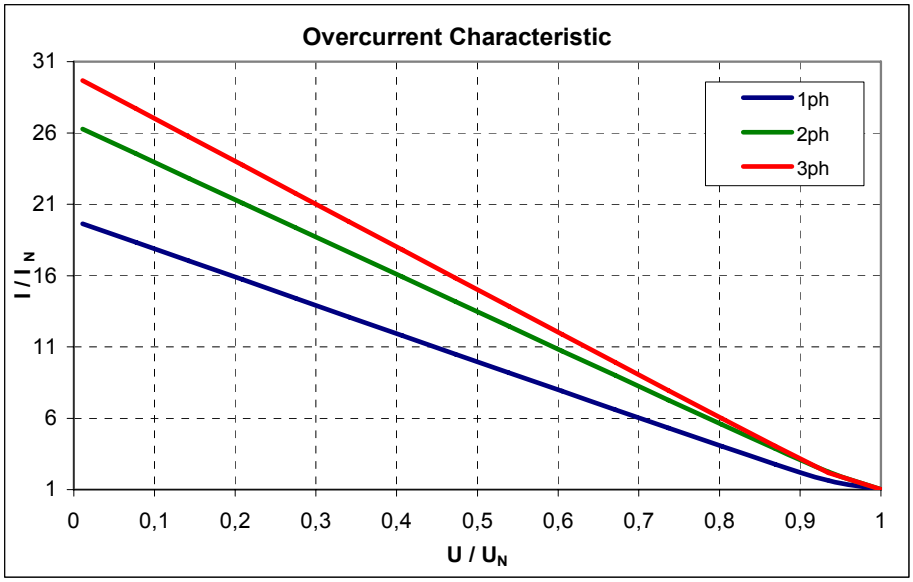


Figure 3-17: Synchronous Emulation overcurrent characteristic (RMS values)

A disadvantage of this control strategy can be seen in Figure 3-18, which presents the average active and reactive power output of the converter. It can be seen that the output power decreases with lower remaining voltage. Depending on the type of fault, the output power may reach very small values; which means that the generated power over this limit must be spilled. The reactive power, on the contrary, increases in a way, which may be beneficial for the voltage support process.

However, another disadvantage of this control method regards the size of the DC-Link capacitor.

3.5.3.3. Calculation of DC-Link Capacity

The DC-Link capacity requirements may be obtained by applying Kirchhoff's Law on the schematic shown in Figure 3-19.

For an oscillating power requirement having an average power P_{av} and a maximum amplitude of P_{pk}, the differential equation defining the voltage at the DC-Link may be written as:

$$\frac{d}{dt}U_{DC} - \frac{P_{pk}\sin(2\omega t)}{C \cdot U_{DC}} = 0 \qquad (3\text{-}5)$$

If the differential equation is solved, an exact value for the DC-Link capacitor may be found; however, the solution is rather complex and out of the scope of this work; thus, an approximation is made under the following assumption.

The allowed voltage fluctuations are kept rather small, thus having an almost negligible influence on the output current. If this voltage level is assumed to be the mean DC-Link voltage B_0, then the differential equation may be simplified as:

$$\frac{d}{dt}U_{DC} - \frac{P_{pk}\sin(2\omega t)}{C \cdot B_0} = 0 \tag{3-6}$$

Which now has a nice and simple solution of the form:

$$U_{DC} = B_0 - A_0 \cos(2\omega t) \tag{3-7}$$

By substituting in the simplified differential equation and solving for C, the size of the capacitor may be approximated by:

$$C = \frac{P_{pk}}{2\omega(B_0 A_0)} \tag{3-8}$$

Using as reference the nominal DC-Link capacitor size in the range of 0.055 pu, Figure 3-20 plots the overdimensioning requirement of the DC-Link under the following assumptions:

- The input source is a power source with a constant value of exactly the mean output power P_{mean}.
- The minimum DC-Link Voltage $B_0 - A_0$ is set to be 10% over the nominal rectified peak voltage ($1.1\sqrt{6}U_N = 2.7\,pu$).
- The maximum allowed overvoltage in the DC link is 0.5pu ($U_{\max} = 3.2\,pu$), which implies a maximum ripple amplitude A_0 of 0.25pu (refer to Figure 3-19).

Strategy: **Synchronous Emulation**

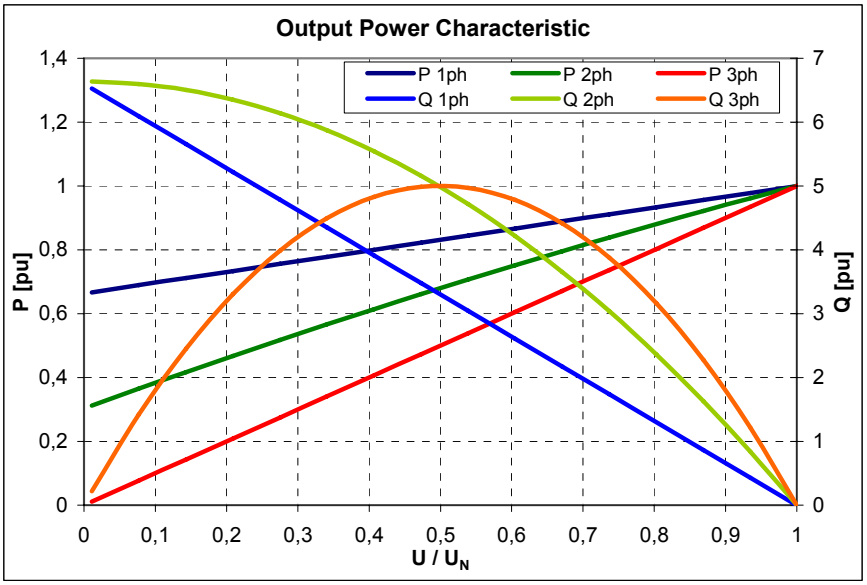


Figure 3-18: Mean Active and Reactive Power output of the converter

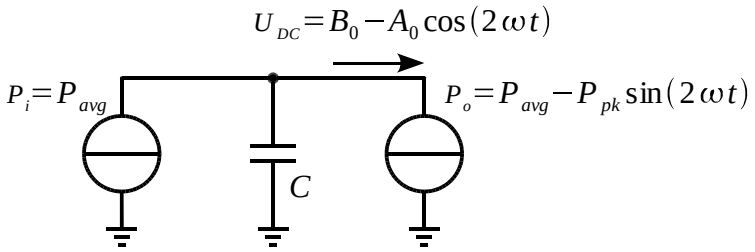


Figure 3-19: Equivalent circuit for calculation of DC-Link capacitor

It can be seen that the DC-Link requirements can ascend rapidly to values that are even higher than the capacitor DC-Link requirements for one phase converters.

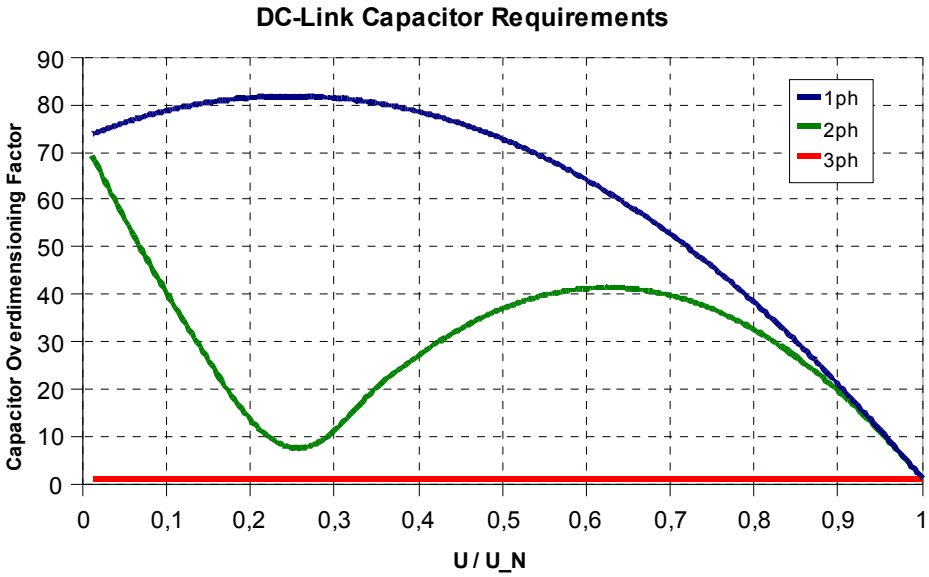


Figure 3-20: DC-Link capacitor requirements for compensating power fluctuations

3.5.4. Delta Instantaneous Active-Reactive Control

3.5.4.1. Concept

The Instantaneous Active-Reactive Control (IARC) has been described by [Rodriguez, 2007] and is considered a valuable control strategy as it can completely control the active and reactive power injection to the grid.

This implies that the DC-Link capacitor requirements can be, at least theoretically[5], fulfilled with nominal DC-Link requirements (see Section **Fehler! Verweisquelle konnte nicht gefunden werden.** in page **Fehler! Textmarke nicht definiert.**). This control technique is described by [Rodriguez, 2007] as follows[6]:

> The most efficient set of currents delivering instantaneous active power P to the grid can be calculated as follows [Akagi, 1984]:
>
> $$i_j = gU_j \quad \text{with} \quad g = \frac{P}{|U|^2} \tag{3-9}$$
>
> where |U| denotes the module of the three-phase voltage vector U, and g is the instantaneous conductance that is seen from the inverter output. In this situation, the grid converter is controlled to emulate a symmetric resistance on all three phases [Baumann, 2005]. The value of *g* is a constant in balanced sinusoidal conditions, but under grid faults, however, the negative-sequence component

[5] In practice, a small capacitance should be added to compensate for the reaction time and precision of the control loop.
[6] Variable names have been adapted to the conventions of this document.

gives rise to oscillations at twice the fundamental frequency in |U|. Consequently, the injected currents will not keep their sinusoidal waveform, and high-order components will appear in their waveform. A current vector of equation 3-9 is instantaneously proportional to the voltage vector and therefore does not have any orthogonal component in relation to the grid voltage; hence, it gives rise to the injection of no reactive power to the grid.

As it can be seen, the method described by Rodriguez assumes that i_j may have zero-sequence components as U_j may include these components. However, the majority of three-phase inverters do not have an active neutral and thus cannot inject zero-sequence currents.

Because of this fact, a derivation of the original IARC concept was needed. This derivation was named *Delta* IARC, recalling the properties of Delta-connected generators. The resulting equations are:

$$i_j = g\left(U_{j,1} + U_{j,2}\right) \quad g = \frac{P}{|U_1 + U_2|^2} \tag{3-10}$$

In other words, the reference current is derived from the positive and negative sequence voltages giving only positive and negative currents.

3.5.4.2. Analysis of Simulation

This control strategy yields nominal active and reactive power in a pre-fault condition. Figure 3-21 also shows that the injected currents are perfectly sinusoidal. Nevertheless this condition changes when a fault is present.

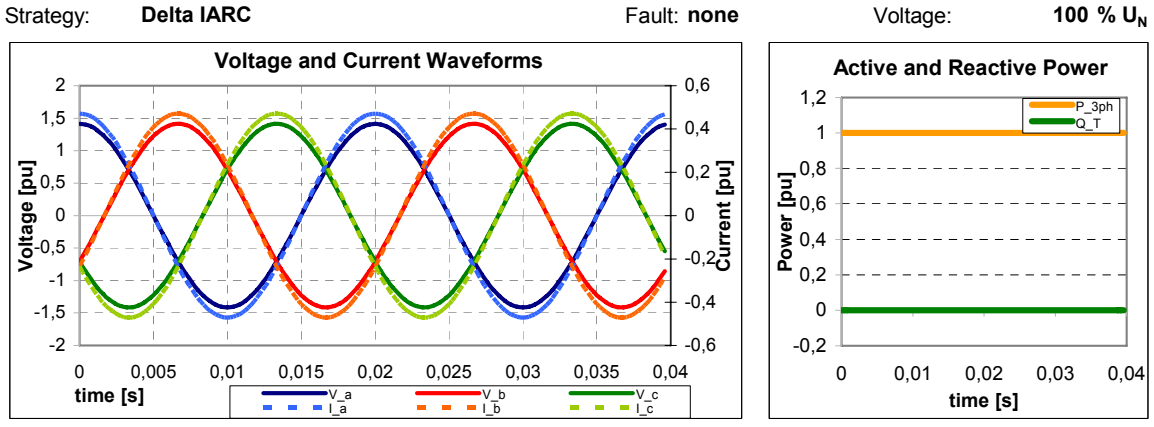


Figure 3-21: Pre-fault Voltage, Current and Power Waveforms

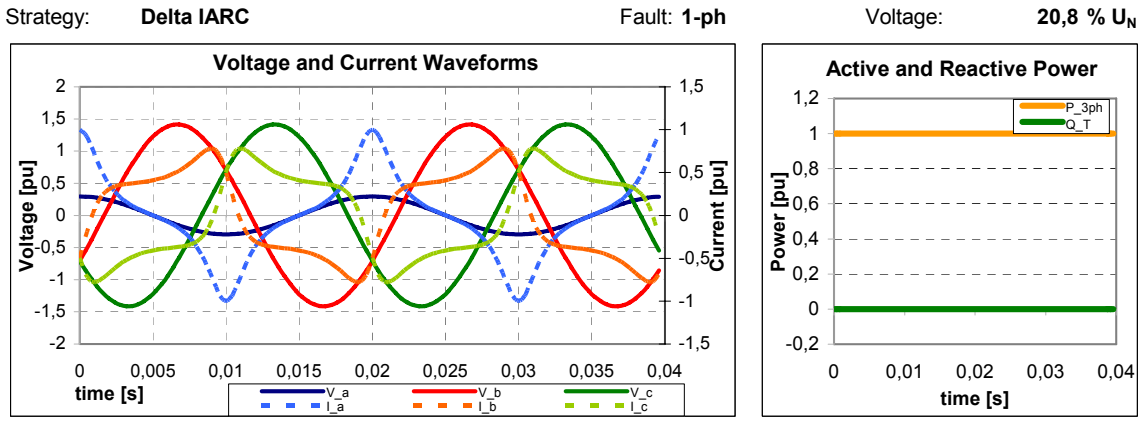


Figure 3-22: Current and Power Waveforms at a single-phase fault condition

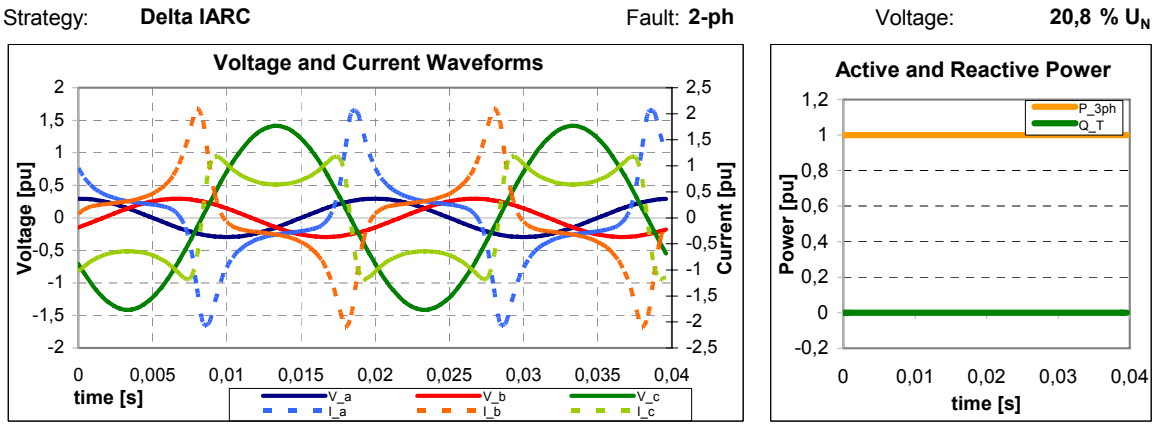


Figure 3-23: Voltage, Current and Power Waveforms during a double-phase fault

In order to maintain P and Q constant as shown in Figure 2-19 and Figure 2-20, the control must inject higher order currents, which yield the distortion seen in the mentioned figures. The distortions have two main disadvantages:

1. The injection of higher currents impact negatively the Total Harmonic Distortion (THD)
2. The harmonic content changes the relation between the peak current and the RMS value of the current, which affects the loading of several components of the inverter.

The first issue restricts from the use of this control strategy if local norms cannot be held[7]. A further analysis as to the maximal limits is being carried out but it is likely to show that one and two-phase faults (with residual voltages under 80%) are not likely to be serviced with this strategy as it is. Figure 3-25 shows the *minimum* THD that can be achieved during single-phase and double-phase faults. Please note that a balanced three-phase fault would not increase the THD of the current but only its magnitude.

[7] As there are no official rules for the operation during fault-events on distribution networks, current regulations (that apply only for normal operation) have been considered.

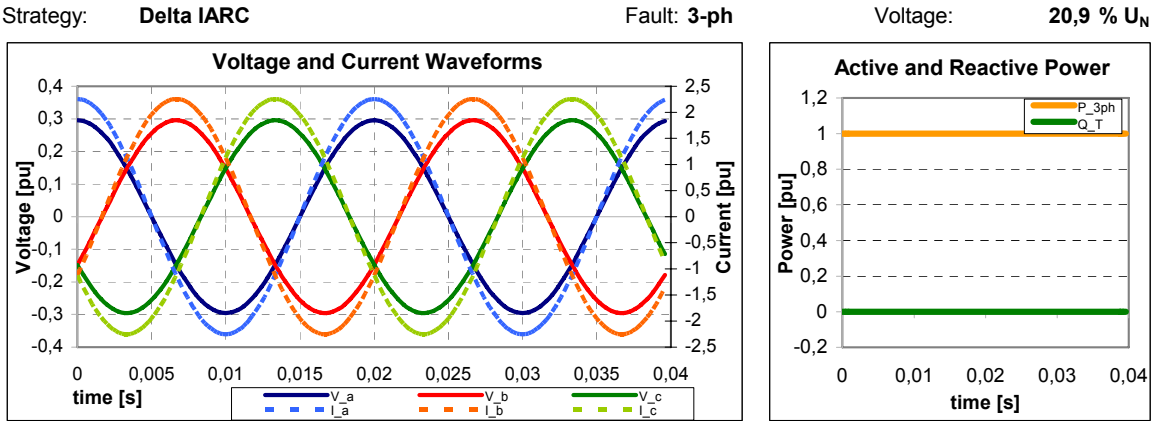


Figure 3-24: Voltage, Current and Power Waveforms during a three-phase fault

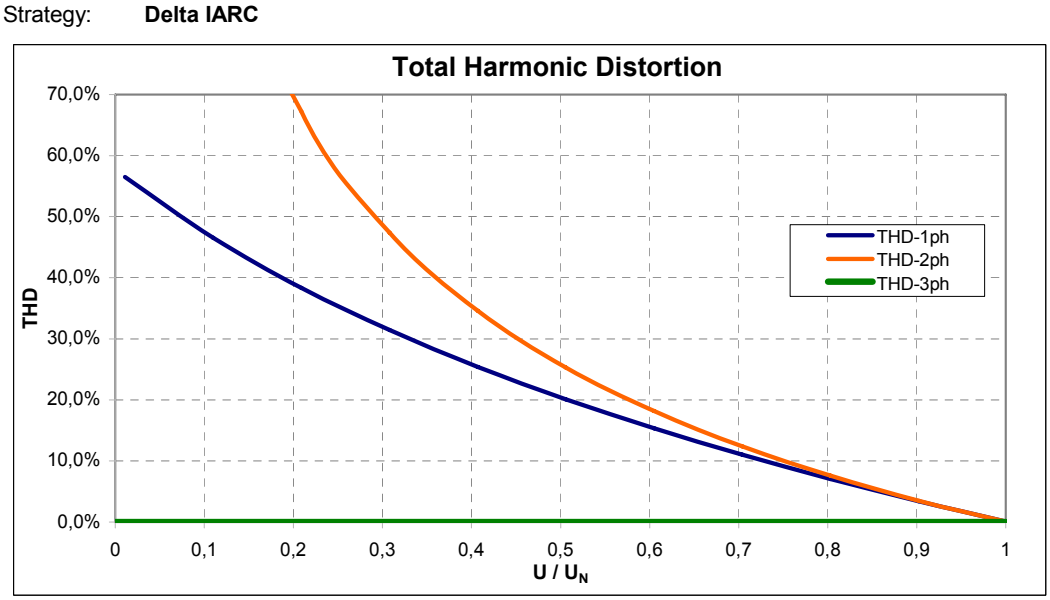


Figure 3-25: Total Harmonic Distortion of Delta IARC-generated currents in fault conditions

The THD in Figure 3-25 is calculated according to[8]:

$$THD = \frac{\sqrt{i_{RMS}^2 - i_{H\,01,RMS}^2}}{i_{H\,01,RMS}} \tag{3-11}$$

Where THD is the Total Harmonic Distortion of the current, i_{RMS} is the RMS value of the injected current and $i_{H\,01,RMS}$ is the RMS of the fundamental frequency. Please note that this calculation *does not* include the effect of the current ripple present in inverter-based generators. This could eventually lower the limit allowed for lower-order harmonics.

[8] Derived from Voltage THD as per IEC61000-4-7 (2002) as explained by [LEM, 2005]. This method might have small deviations to the actual Norm as it includes all interharmonics instead of harmonics in 5 Hz steps.

Regarding the overloading of the components, the Delta IARC provides an advantage over the simple Synchronous Machine Emulation. As it can be seen in Figure 3-26, the maximum overload at residual voltages of around 15%-20% ranges from 500%-650% of the nominal current for three-phase faults: A value around 25% of the one required for the Synchronous Machine Emulation.

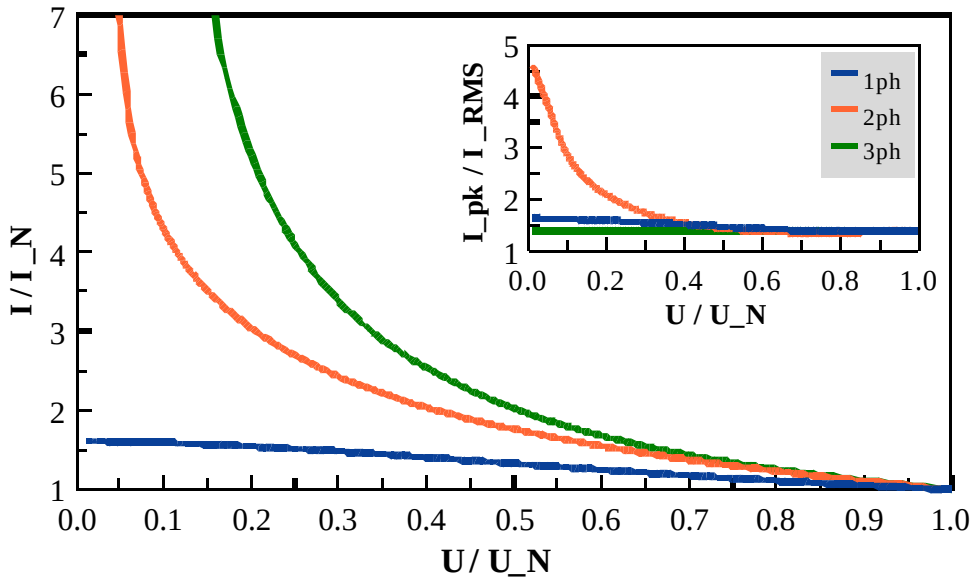


Figure 3-26: Current overloading using Delta IARC strategy

Nevertheless, as explained before, the form factor (I_{PK}/I_{RMS}) of the resulting current increases with decreased residual voltage. This effect implies a different loading of the different components in the inverter, especially in the instantaneous junction temperature of the transistors or the temperature of the insulation in inductors.

3.5.5. Positive-Negative Sequence Compensation

3.5.5.1. Concept

The Positive-Negative Sequence Control (PNSC) strategy is based on the premise that the active power oscillations present in an unsymmetrical system can be reduced or even eliminated if negative- sequence currents are added to the reference current. As explained by [Rodriguez, 2007][9]:

> Active power P can be delivered to the grid by injecting sinusoidal positive- and negative-sequence currents at the PCC.

$$I = \frac{P}{|U_1|^2 - |U_2|^2}(U_1 - U_2) \qquad (3\text{-}12)$$

[9] Variable names have been adapted to the conventions of this document.

Equation 3-12 indicates that the injected current and voltage vectors have different directions. Consequently, the instantaneous reactive power that is delivered to the grid is not equal to zero but exhibits second-order oscillations.

In contrast to the Delta IARC Strategy, the PNSC will inject sinusoidal currents, eliminating the problem with the THD limitations but as stated by Rodriguez, this technique generates oscillations in the reactive power injection.

3.5.5.2. Analysis of Simulation

Figure 3-27 shows, as done for all control strategies, the reaction of the control to a perfectly balanced grid. As expected, in-phase, sinusoidal currents having their nominal level are present.

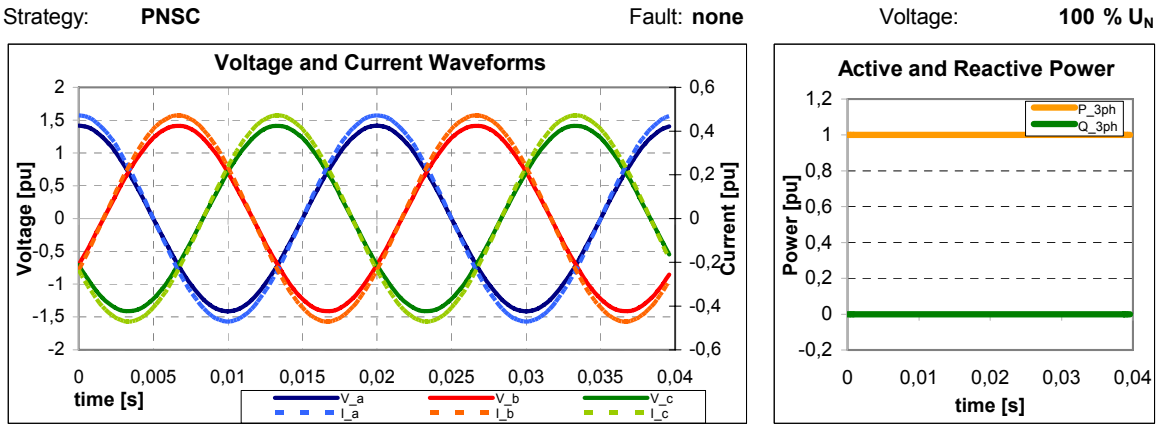


Figure 3-27: Pre-fault Voltage, Current and Power Waveforms

As soon as a fault is present, the PNSC will try to inject both positive and negative sequence currents so that the active power does not show the oscillations observed in Figure 3-14. Nevertheless, oscillations in the reactive power are still present. It is important to note that this compensation implies an unsymmetrical reactive power distribution as well. As depicted in Figure 3-28 and Figure 3-29. While current in phase a (the faulted phase) in Figure 3-28 is in phase with the voltage, line b generates reactive power and line c absorbs reactive power. In an analogue manner in Figure 3-29, line c injects power at a unity power factor, while line *b* injects power and line *a* consumes reactive power. For an explanation on how instantaneous reactive power is calculated, please refer to [Czarnecki, 2003].

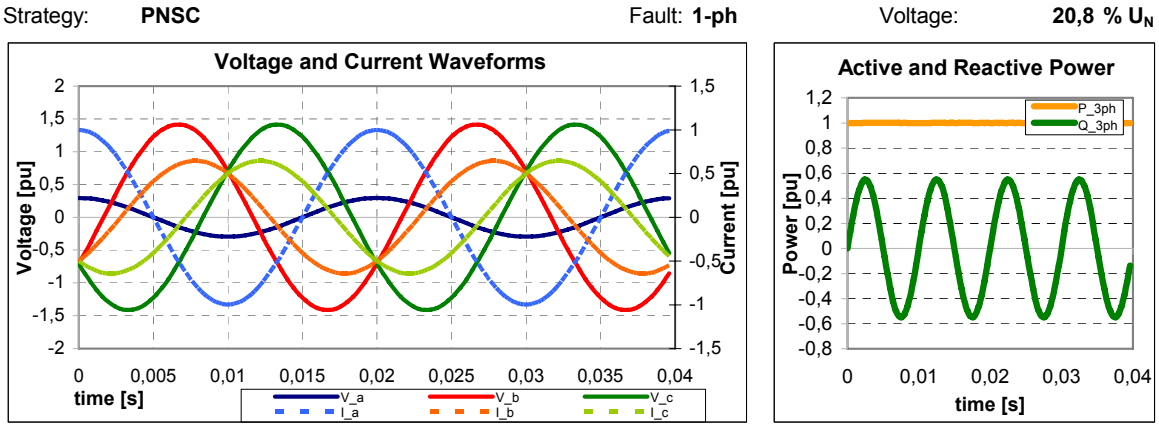


Figure 3-28: Voltage, Current and Power Waveforms for a 1-phase fault

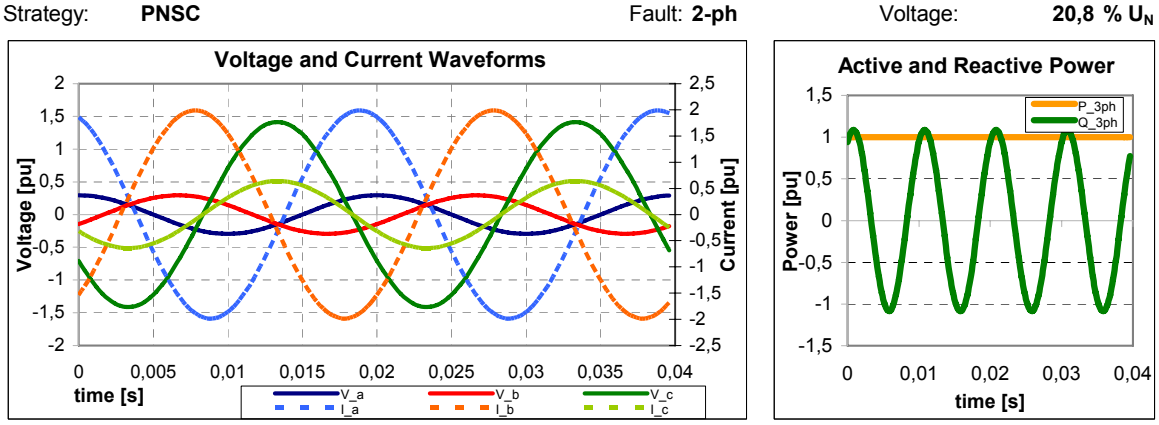


Figure 3-29: Voltage, Current and Power Waveforms during 2-phase faults

This effect may – in some cases – not be desirable and the control may be required to provide a suitable reactive power proportion.

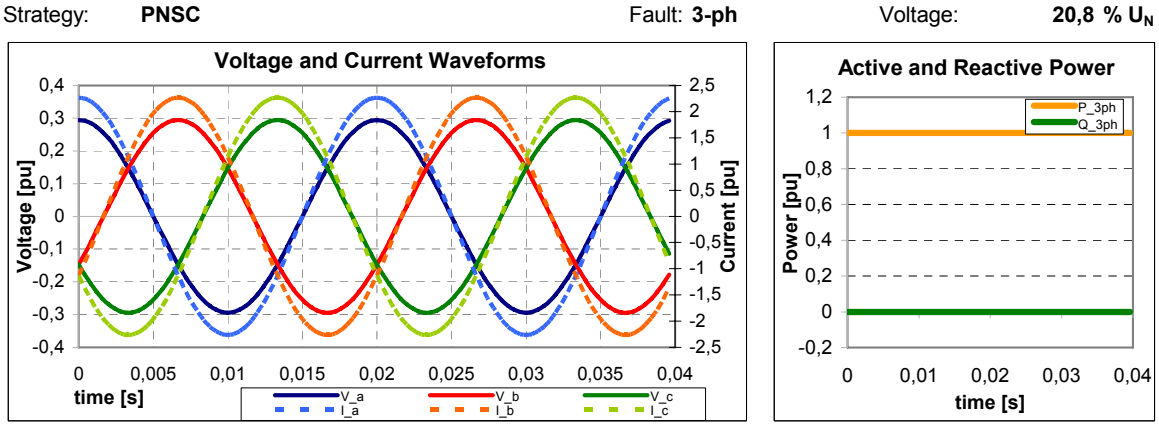


Figure 3-30: Voltage, Current and Power Waveforms during 3-phase faults

The required overload capability can be seen in Figure 3-31. It has a similar characteristic as the Delta IARC but has the advantage that the peak-to-rms value remains constant.

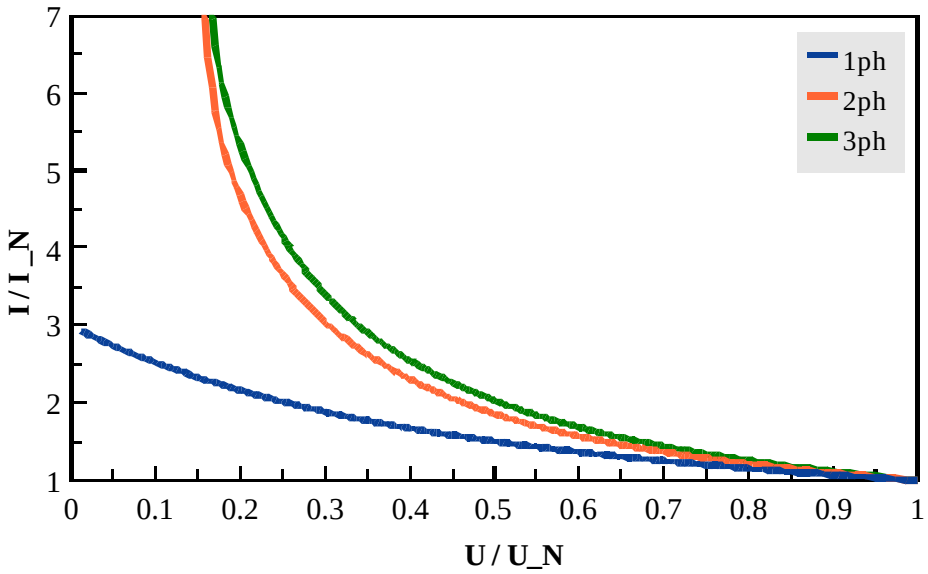


Figure 3-31: Overloading factor for PNSC Control

3.6. Integration of FRT Capability in the Control Structure of the Inverter

3.6.1. Concept

Regardless of the FRT control strategy adopted, the usual control of a three-phase inverter is done by implementing a Space Vector Modulation algorithm. This algorithm, which overview can be seen in Figure 3-32, is based on the concept of a synchronous reference frame. In this context, the control may be done as if both currents and voltages were stationary (no sinusoidal but constant values).

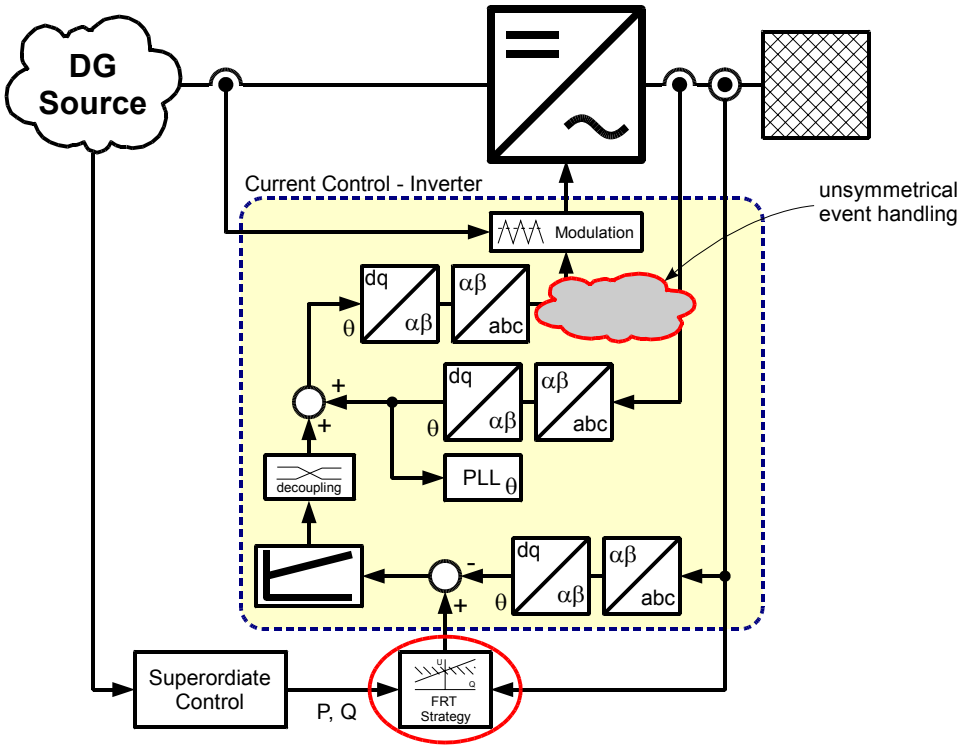


Figure 3-32: State-of-the-art SVM-based control

On top of this control, on the areas indicated in red, the FRT control is implemented. This will modify two important sections: The active and reactive power scheduling and the unsymmetrical event handling.

- **The active-reactive power control** is in charge of adjusting the phase angle and amplitude of the injected current according to the requirements and the maximum capability of the converter.
- **The unsymmetrical event handling** is responsible for maintaining the scheduled active power as constant as possible and to inject currents which are proportional to the voltage dip on each phase.

In this work, the active-reactive control has been programmed in such a way, that the inverter will inject up to six times its nominal current when any of its phase voltages reaches 0V and will have a linear characteristic up to no overloading when measuring nominal voltage and above. Figure 3-33 illustrates this characteristic.

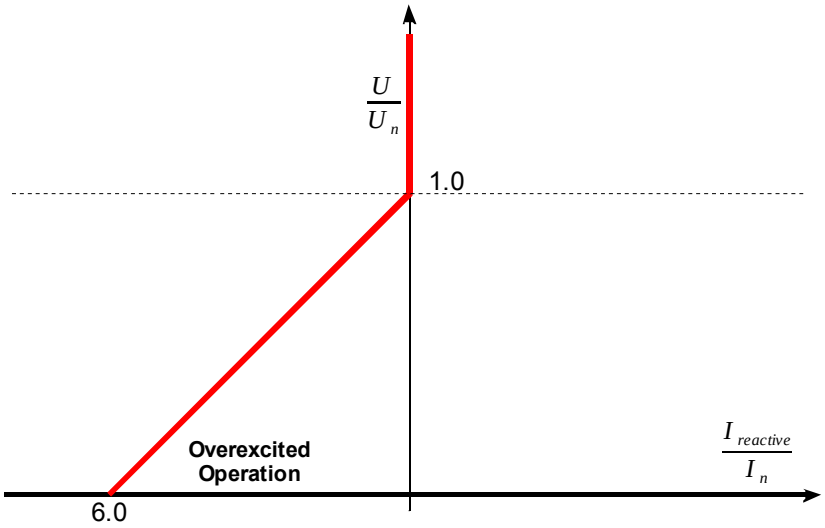


Figure 3-33: Reactive current characteristic

The unsymmetrical event handling will be a direct implementation of the Positive-Negative Sequence Control (See previous section).

3.6.2. The Test Network

The above control was implemented and tested using plexim's plecs® extension for Matlab® Simulink®. Figure 3-34 shows the schematic of the network.

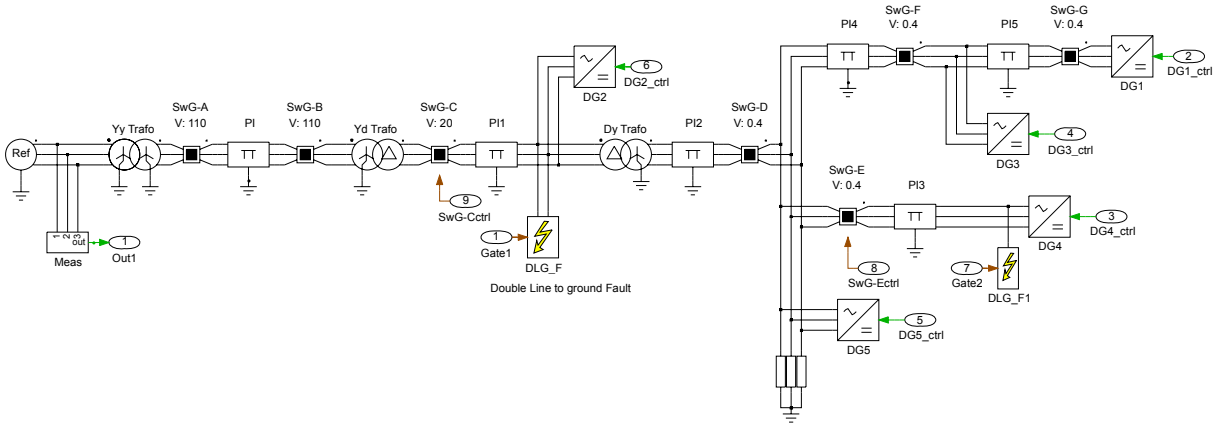


Figure 3-34: Schematic of the testing network

For the scope of this work, one test was carried out: A one-phase-to-ground fault simulation at the terminals of DG4 (which trips the protection at SwG-E).

The fault starts at a t = 100ms and is cleared at t = 250ms, when protection SwG-E is triggered. Additional specifications are:

- All low-voltage DG units have a nominal power of 80kW and are operating at 63% immediately before the fault starts.
- DG2 is connected at t=75ms and has a nominal power of 500kW, but the pre-fault scheduled power is 300kW

- All switching stations (SwG-X) provide an overvoltage protection which triggers by 150% of the nominal voltage.
- DG1 and DG3 have loads (10 and 5kW respectively) connected at the PCC.

3.6.3. Analysis of Simulation

Figure 3-35 to Figure 3-39 show the results of the simulation for all 5 DG Units. Due to the nature of the fault (unsymmetrical), it is expected that unsymmetrical currents be injected to the network from all DG units.

It can be observed that DG1 senses the smallest voltage dip of the units connected to the low voltage network. It also reacts accordingly by injecting unbalanced currents to the grid. The power factor is also varied to enable the injection of higher currents. However, since the residual voltage is over 50% of the nominal voltage, the scheduled overcurrent is just little over twice the scheduled current.

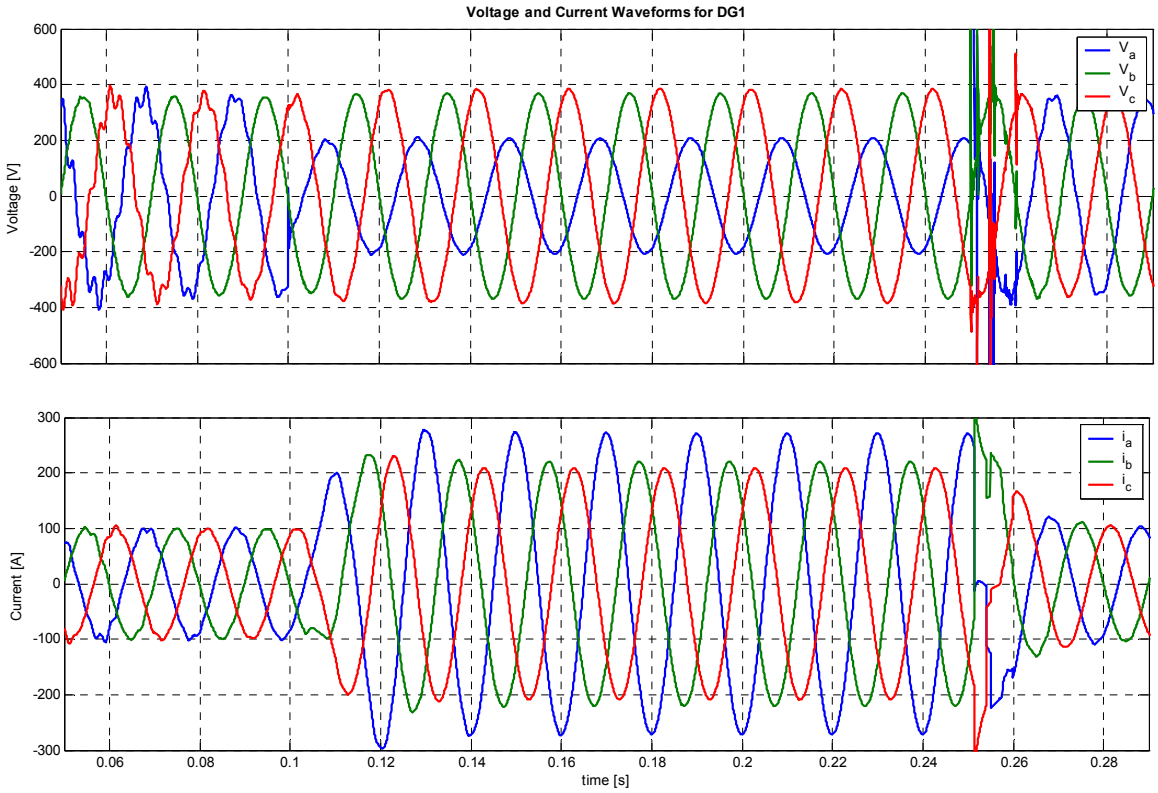


Figure 3-35: Results for DG Unit 1

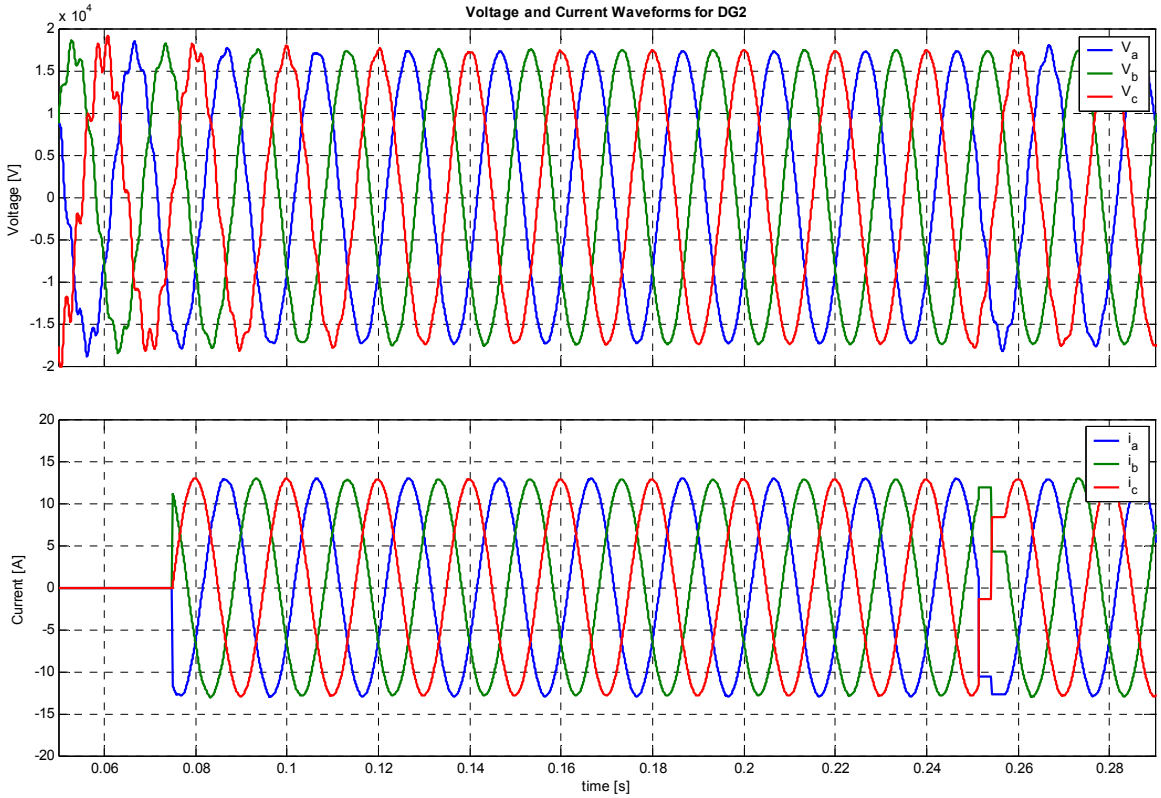


Figure 3-36: Results for DG Unit 2

DG2 exhibits almost no reaction to the fault when it occurs but presents a severe distortion when the fault is cleared. This has mainly to do to the transformation of the voltages into its positive and negative sequences. This may be corrected by a better tuning of the transformation's parameters.

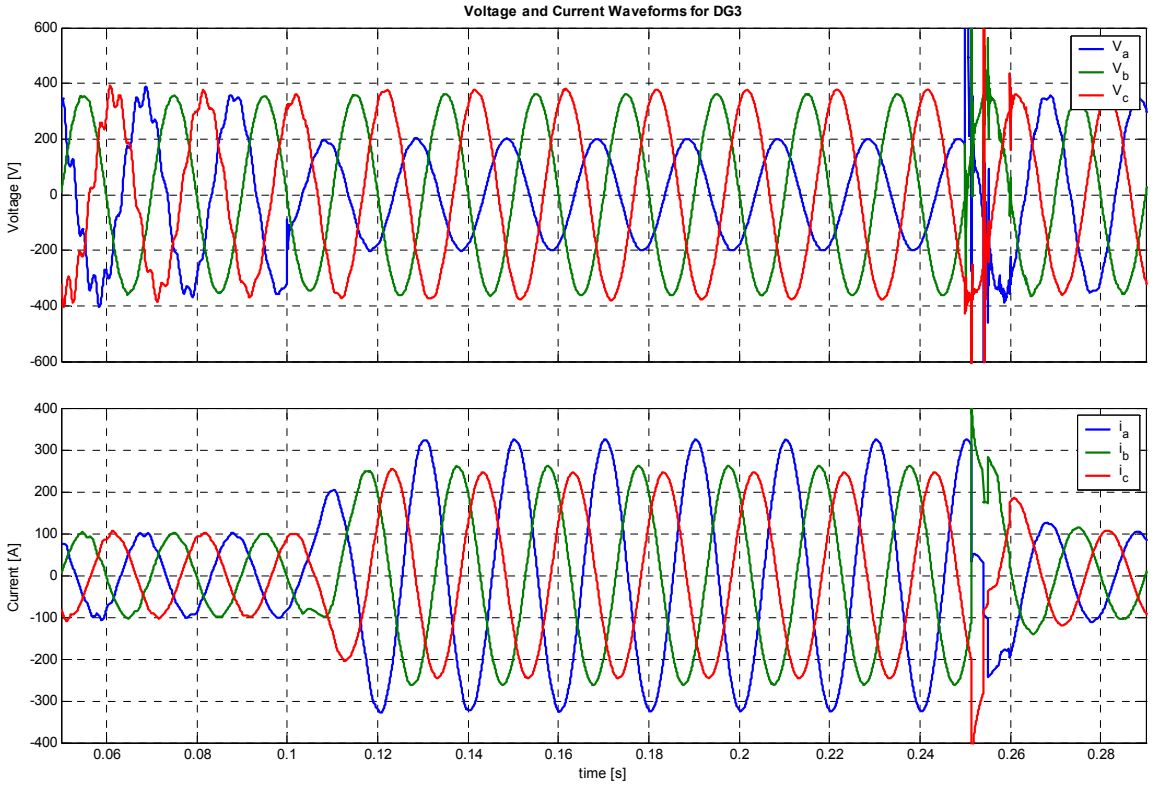


Figure 3-37: Results for DG Unit 3

DG3 exhibits a very similar response as DG1. The effect of the clearance transients can also be recognized in this unit (around 250ms) although it is also combined with the effect of the power factor restoring. Also, as expected, the injected transient current is higher than the one from DG1.

DG4 (Figure 3-38) is connected to the faulted bus and thus measures almost no voltage at the faulted phase. It thus injects the maximum reactive current while trying to maintain the active power constant. The overcurrent reaches over 10 times the scheduled current (about 6 times the nominal current).

As expected DG4 will not return to normal operation after the fault is cleared as the circuit breaker will isolate the whole section from the network.

DG5 exhibits also a similar characteristic as DG1 and DG3. Since it is the second closest inverter to the fault, its transient current is also larger than the other two generators connected to the low voltage network.

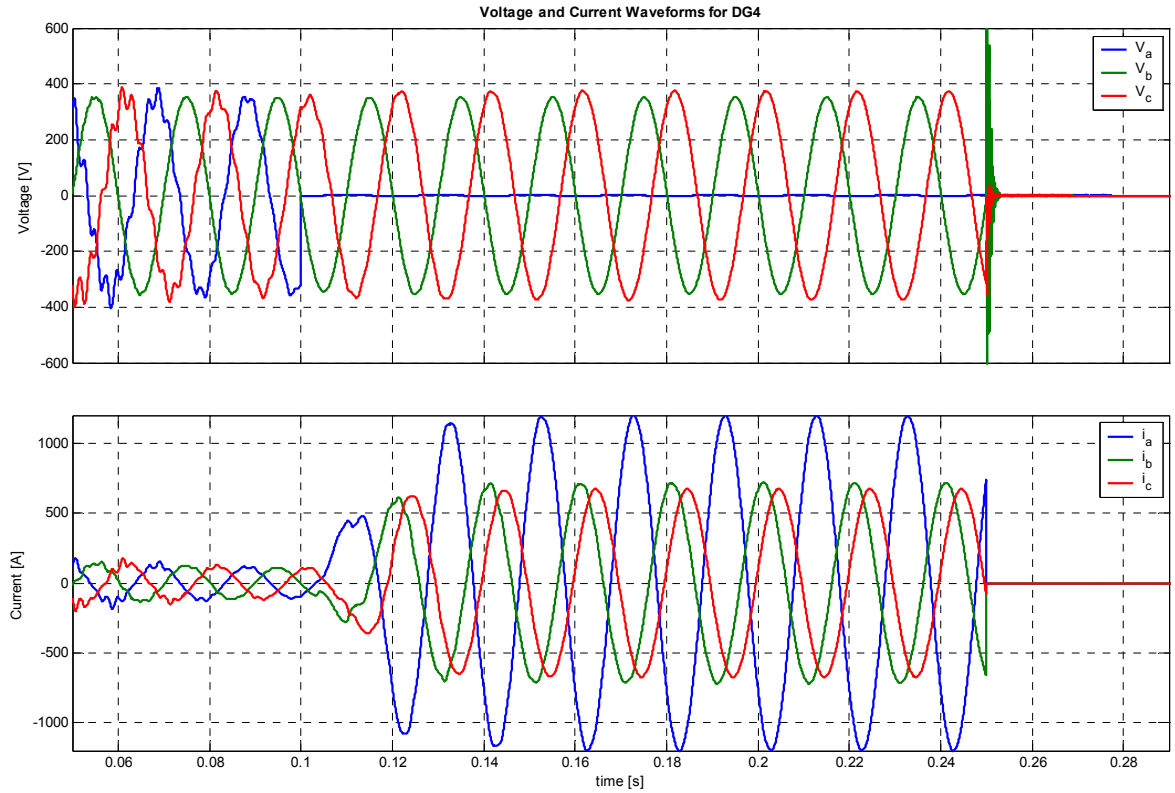


Figure 3-38: Results for DG Unit 4

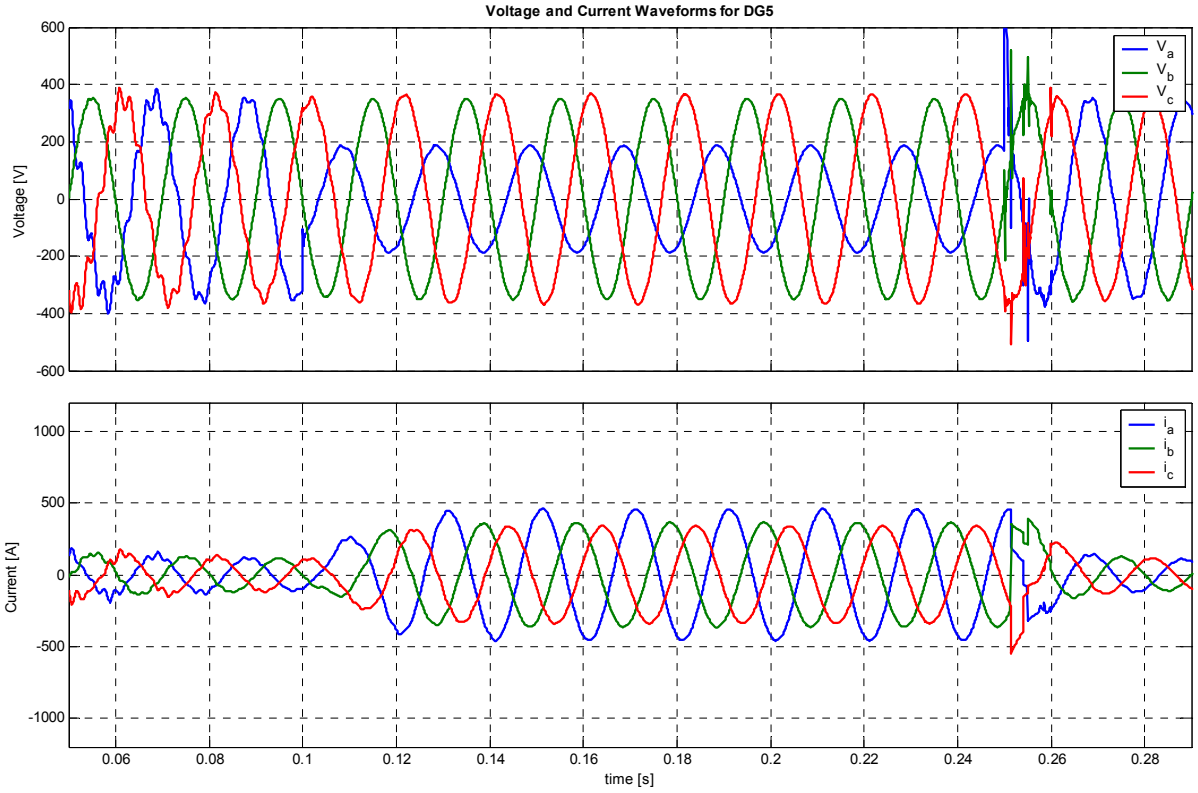


Figure 3-39: Results for DG Unit 5

3.7. Thermal Characterization of Power Electronics Components

An important part of this work regards the thermal overloading of inverters. The overload capability is normally given by the capacity of the elements of the inverter to dissipate heat. Of these components, the power electronics components are the most likely to be the most restricting. Passive components such as chokes do not differ from machine windings and are able to withstand a higher overload. Of course, depending on the saturation curve of the chokes, an increase over its nominal current may lead to the loss of the inductance (saturation), leading to extremely high currents that may damage the inverter.

To exclude the saturation of the inductor, an inductor which can handle up to 400% of the nominal current without losing too much inductance, has been selected.

Figure 3-40 shows a *simplified version* of the thermal model that has been used for the simulations. The left side show a typical configuration of a power module with (from top to bottom) the semiconductor chip, the substrate, baseplate (normally copper or aluminium) isolation means and heatsink.

Although much more complicated, the heatsink is modelled as a complex thermal impedance linking the ambient temperature T_{amb} and the baseplate temperature T_{bp}. To derive the junction temperature of both the IGBT and the antiparallel diode ($T_{j,i}$ and $T_{j,d}$ respectively), another set of complex impedances is required. It is important to note that these complex impedances are formed from at least 4 sections (not depicted) to account for the thermal inertia of all the layers going from the junction to the baseplate. The model used herein is based on the calculations made by [Iposim, 2007].

The power dissipated by the leads has been assumed to be transferred directly to the baseplate (P_l).

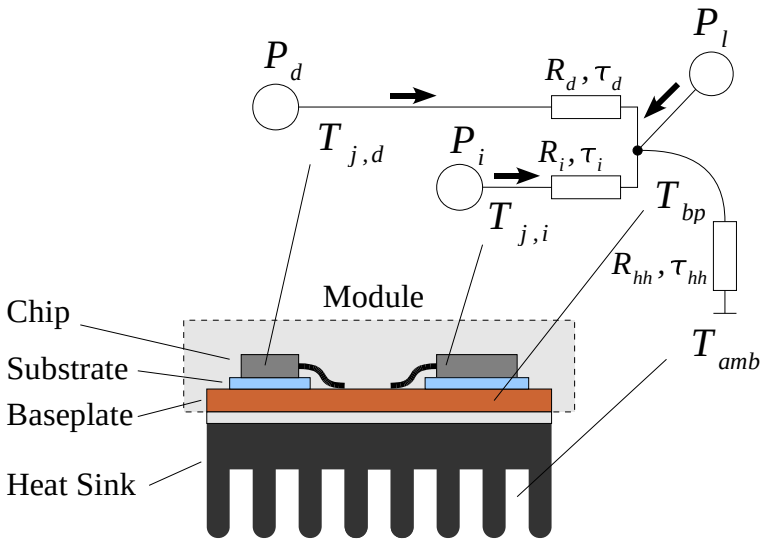


Figure 3-40: Simplified Model for thermal simulations

3.7.1. Definitions

The power losses used in the thermal simulation have been calculated by using simple IGBT and diode models, assuming nominal values at 125°C operating temperatures (a sort of worst case scenario). The following sections explain the power loss approximations used in this document as presented by [Iposim, 2007].

3.7.1.1. Power Losses in IGBTs

Two main losses mechanisms have been studied in this section: Switching and conduction losses. The conduction losses P_{cond} can be approximated by the following equation:

$$P_{cond} = \frac{1}{T_0}\int_0^{T_0}(V_{CE0} + R \cdot i_l)\cdot i_l \cdot d_c \cdot dt \tag{3-13}$$

Where T_0 is the switching period, V_{CE0} is the threshold voltage, R is the slope of the saturation voltage (at 125°C), d_c is the duty cycle that occurred as a proportion of the on time to the total switching time and i_l is the current flowing through that inverter leg.

The switching losses have been calculated as:

$$P_{sw} = \frac{1}{T_0} E_{sw} \frac{i_l}{i_{rated}} \cdot \frac{V_{DC}}{V_{nom}} \tag{3-14}$$

Where i_{rated} is the rated current of the device, E_{sw} is the switching energy (On and off switching), V_{DC} is the DC-Link voltage and V_{nom} is the nominal blocking voltage of the device. Please note that the correction of the switching losses due to different DC-Link voltages is only valid for B6 inverters and shall not exceed the 20%.

3.7.1.2. Power Losses in Diodes

For the case of diodes, the conduction losses are calculated in a very similar way as the ones for transistors:

$$P_{cond} = \frac{1}{T_0}\int_0^{T_0}(V_0 + R \cdot i_l)\cdot i_l \cdot (1 - d_c)\cdot dt \tag{3-15}$$

Where V_0 is the threshold voltage and R is the slope of the saturation voltage (at 125°C), d_c is the duty cycle that occurred as a proportion of the on time to the total switching time.

Since for diodes, the turn-on switching is normally disregarded, the switching losses are known as reverse recovery (turn-off) losses, which are of the form:

$$P_{sw} = \frac{1}{T_0} E_{rec}\left(0.45\frac{i_l}{i_{rated}} + 0.55\right) \tag{3-16}$$

Where E_{rec} is defined as the reverse recovery losses. As it can be seen, the reverse recovery losses have a considerable component which does not depend on the current that is being switched but on the only fact that the diode is switched off.

3.7.1.3. Lead and copper losses

The leads that bring the current in and out of the power module generate losses as well. These losses can be calculated as normal resistive losses of the form:

$$P_{cu} = \frac{1}{T_0}\int_0^{T_0} R_{cc'+EE'} \cdot i_l^{\,2} \qquad (3\text{-}17)$$

Where $R_{cc'+EE'}$ is the lead resistance. As said above, this power is considered to be directly injected to the baseplate (P_l in Figure 3-40).

3.7.2. Thermal Loading

Once the different loss mechanisms have been described, the heat flows may be calculated and from them, the temperature distribution. As mentioned before, the thermal network is a complex set of resistances and inertias. As an industry standard, these sets are restricted to an approximation of four complex impedances *per component* as shown in Figure 3-41.

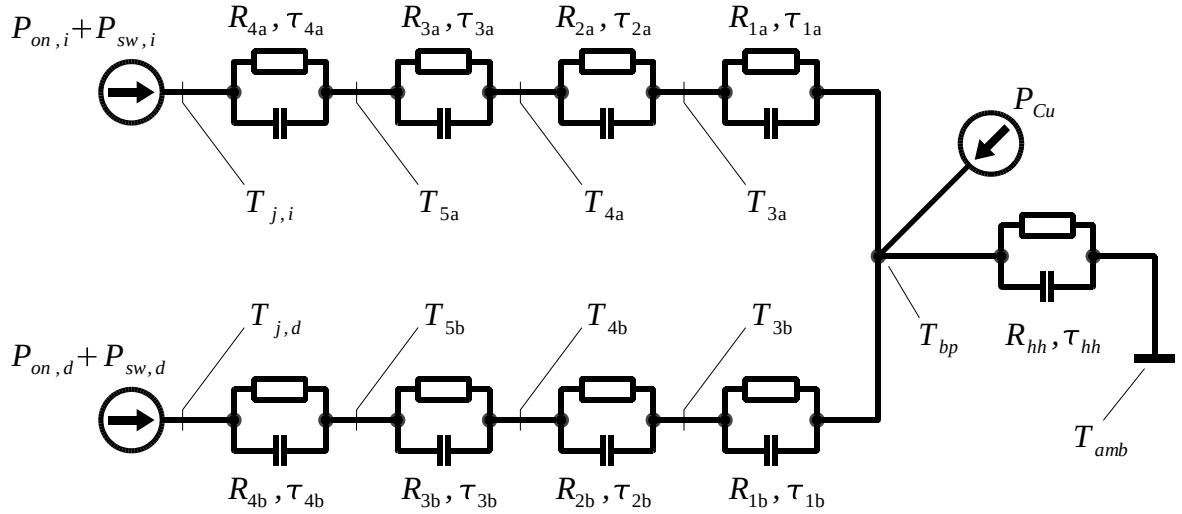


Figure 3-41: Used model for thermal simulations

The last thermal impedance (R_{hh}, τ_{hh}) represents the heat sink. It is important to note that by this thermal model only $T_{j,l}$, $T_{j,d}$ and T_{bp} have a physical interpretation, all other temperature are called state temperatures and have no real relation with the different module components.

Figure 3-42 shows the steady state temperature development for one grid cycle (20ms) in one inverter arm[10] for a unity power factor. The plot shows also the power losses at this arm.

[10] An IGBT + Diode Unit

The losses on the inverter arm are calculated as explained previously. By applying the calculated losses to the thermal network shown in Figure 3-41, the junction temperature of both the IGBT and its diode is obtained.

Of special interest are the characteristics of the power losses. It can be seen that the first half cycle, a considerable part of the losses is produced. A this time, the IGBT is the main component driving the current while the diode of the same arm does nothing. When the waveform is reversed (the negative half wave) the IGBT does not actively drive any current but the complementary one does. At this time, the antiparallel diode is the one which carries the current; however the average of this current is relatively small.

As it can be seen, the losses at the diodes are much less than the ones at the IGBT for power factors near one. This loading changes with changing power factor until the diode's load is larger than the one of the IGBT.

It can also be observed that the maximum temperature of the IGBT is much higher than the one of the diode. This can be of an advantage when dealing with fault conditions since, most of the time, the short circuit current exhibits a low power factor. This fact may allow a higher overload capability.

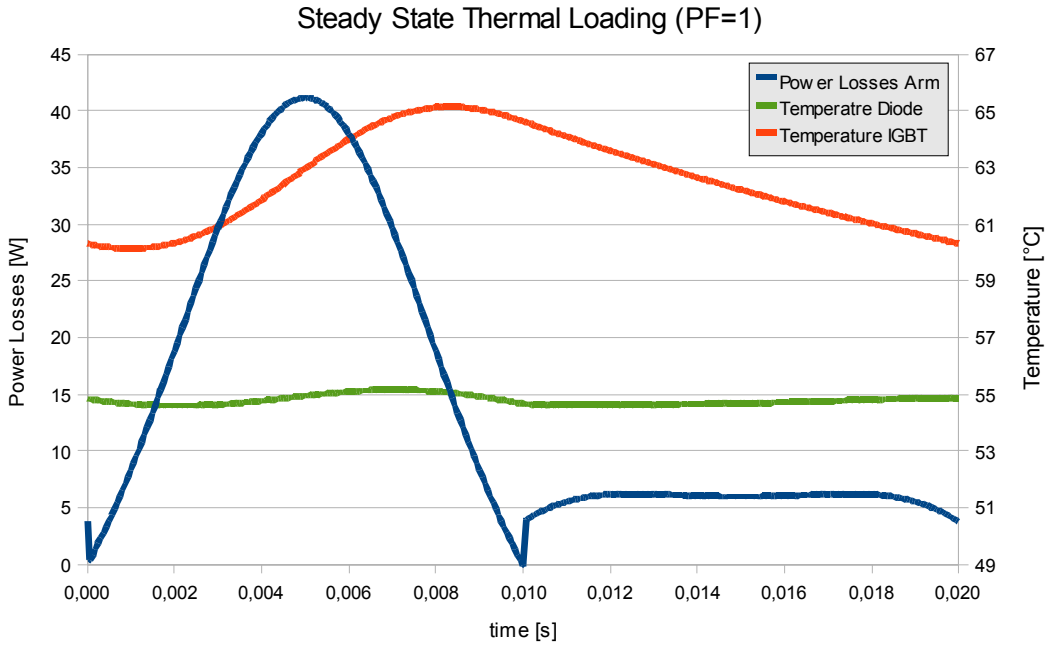


Figure 3-42: Steady-state cyclic load for a 2.3kW one-phase inverter (20A IGBT Module)

3.7.3. Overload Capability of B6 Inverters

In order to provide a general overview of the overload capabilities of inverters, the case of B6 inverters (Three-phase two-level inverters with three active legs) was analysed. Since this topology is one of the most commonly used, the results should give a broad overview of both the technique and the application of this capability.

The sample inverter is a 12.5kW inverter, three-phase (nominal current of 18A), DC-link Voltage of 620V, switching frequency of 16kHz, 3 x 2.9mH 18A Inductors (multi-E sendust

Alloy), a thermal time constant of the Heat Sink of around 100s and an ambient temperature of 40°C.

In this section, all 208 available IGBT Modules of the 1200V class from the Manufacturer Infineon were applied to the configuration and an estimation of their maximum operating power as well as of its efficiency curve were calculated. Modules having a maximum operating current of less than 18A, as well as modules with a calculated European efficiency of less than 90% were screened out.

Since plotting over a hundred efficiency curves does not clarify anything, it was decided to evaluate the modules upon the estimated maximum efficiency, the estimated European efficiency and the estimated CHP20 efficiency. The latter two are explained below.

3.7.3.1. The European Efficiency

In order to provide simple means of comparing two inverters for *photovoltaic applications*, a weighted average efficiency method was developed. This weighted average is based on the average operation hours an inverter is driven at a certain fraction of its nominal power at an average European region. This is defined as [Rooij, 2004]:

$$\eta_{eur} = 0.03 \cdot \eta_{5\%} + 0.06 \cdot \eta_{10\%} + 0.13 \cdot \eta_{20\%} + 0.10 \cdot \eta_{30\%} + 0.48 \cdot \eta_{50\%} + 0.20 \cdot \eta_{100\%} \qquad (3\text{-}18)$$

3.7.3.2. The CHP20 Efficiency

Since not all DG is photovoltaic, it was decided to include another important share of DG categories: The inverter-based CHP Units. Figure 3-43 shows the heating requirements of a typical household in Germany as published by [Hartmann, 2003] it represents the probability density function of the heating requirements as per the VDI 2067 [VDI2067-1986] code, considering a setpoint temperature of 15°C.

As stated by [Milles, 2006], the best investment return of a CHP Unit comes when it is sized to cover around 20% of the thermal load of the year to prevent the CHP from working at bad efficiency points. By using the two above premises, an approximation of the average operation times at different operating conditions may be obtained and can be used to create a weighted average, which will be called the CHP20 efficiency throughout this deliverable.

The CHP20 efficiency may be calculated as

$$\eta_{CHP20} = 0.01 \cdot \eta_{5\%} + 0.02 \cdot \eta_{10\%} + 0.02 \cdot \eta_{20\%} + 0.04 \cdot \eta_{30\%} + 0.16 \cdot \eta_{50\%} + 0.75 \cdot \eta_{100\%} \qquad (3\text{-}19)$$

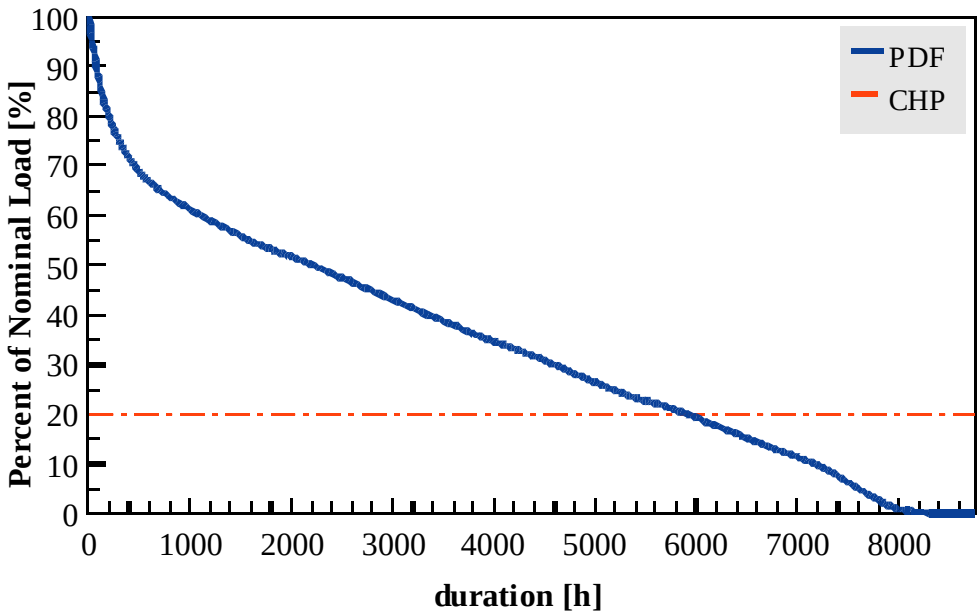


Figure 3-43: Probability density function of heating requirements as per VDI 2067 [VDI2067-1986] for a setpoint temperature of 15°C

3.7.3.3. Impact of Overload Characteristic in the Inverter's Efficiency

A typical question that arises when analysing incorporating additional services in an inverter is the impact of this changes on the final efficiency of the inverter. For this case, the impact of selecting semiconductors that would withstand a higher steady state load is presented in Figure 3-44.

A general trend for the three types of efficiencies is also plotted. It can be observed that while the maximum efficiency *may* even be improved by selecting semiconductors of higher rating, the general trend in terms of operational efficiency is rather to decrease.

Especially in the case of the European efficiency, which lays a higher weight for part load operation, the figures show that an increase in the overload capability almost inevitably brings a reduction in the efficiency figure. From the weights of the average it can be inferred that the most problematic issue is related to constant losses (for example, control, Auxiliary power supply, switching losses, etc), which have a high impact on the efficiency at small power values.

An option for reducing this negative effect might be to reduce the switching frequency. This will reduce the effect of the switching losses at the cost of having a larger inductor (larger size and weight of the inverter).

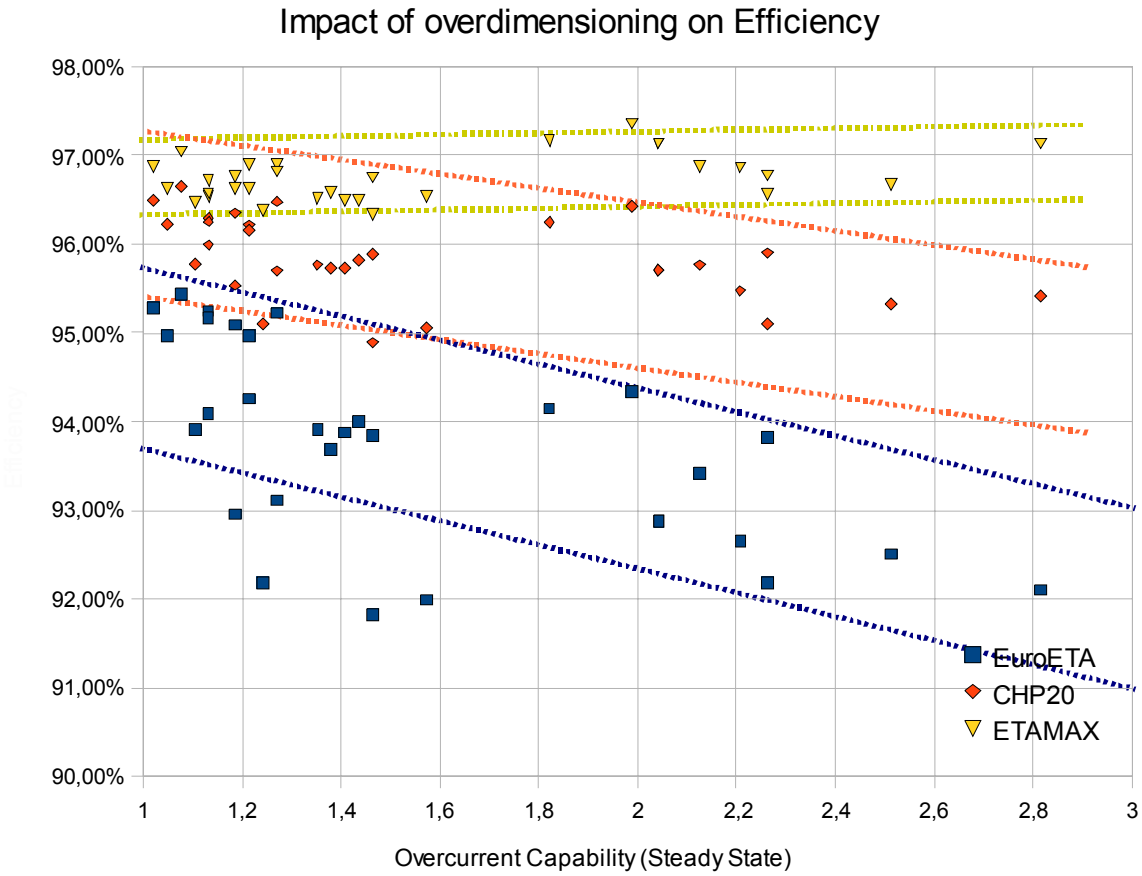


Figure 3-44: Estimated efficiency vs. overcurrent capability for different modules

3.7.3.4. Dynamic Overload Capability and effect of Prefault Power

Once it has been found that a higher steady state overload capability of the inverter can be bought by either letting the efficiency (European, for example) diminish or by increasing the weight and volume of the inverter, it is important to estimate the dynamic overloading capability.

It may be inferred that the dynamic overload capability must be higher than the steady state one, and that its value depends on two main factors: The duration of the overload and the loading state just before the fault occurs.

For evaluating the second factor, an analysis was done for all modules that would provide an overloading capability (regardless of their efficiency), they would be run to their steady state at several operating points and then, it would be determined the maximum overload allowed for a fixed duration. This experiment was done for both a pure active current injection and pure reactive current injection.

The results of this analysis are presented in Figure 3-45 and Figure 3-46. Since each module may have a very different steady-state overload value, the concept of a normalized dynamic overload is necessary.

A normalized dynamic overload can be defined as the ratio between the maximum dynamic overload at a given set of conditions, and the maximum steady state overload. In this way, all modules will exhibit a similar characteristic.

The results presented are the *average* of all studied modules (modules having characteristics falling outside two standard deviations of the whole data were screened off).

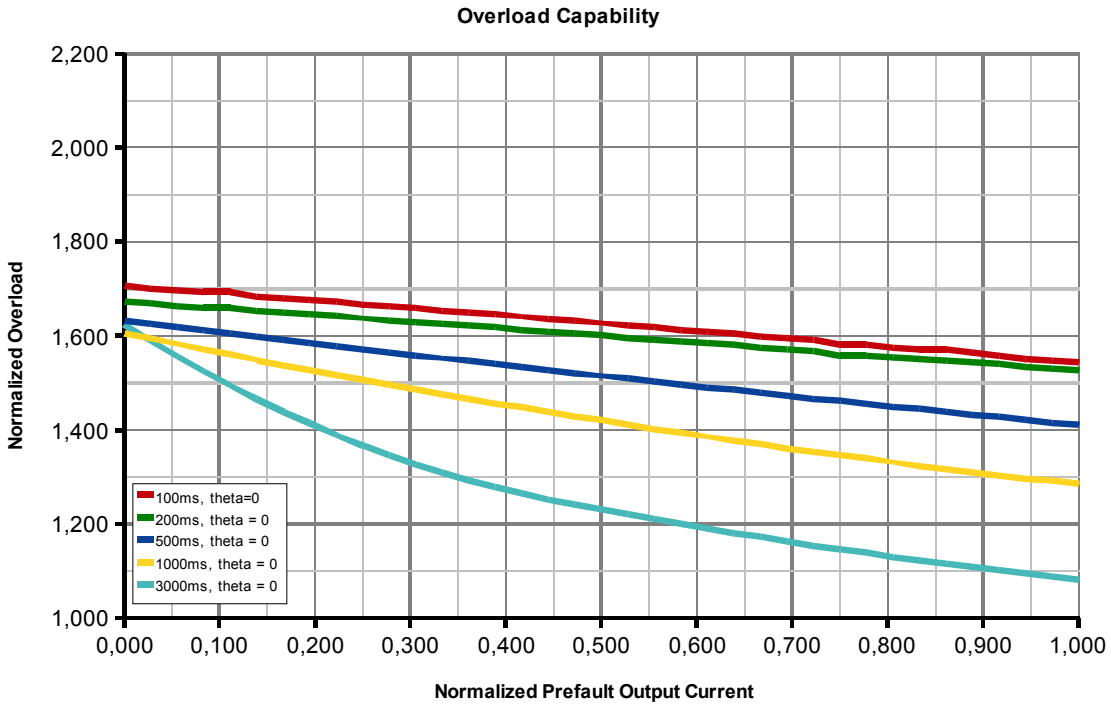


Figure 3-45: Average dynamic overloading capabilities of studied power modules (theta = 0°)

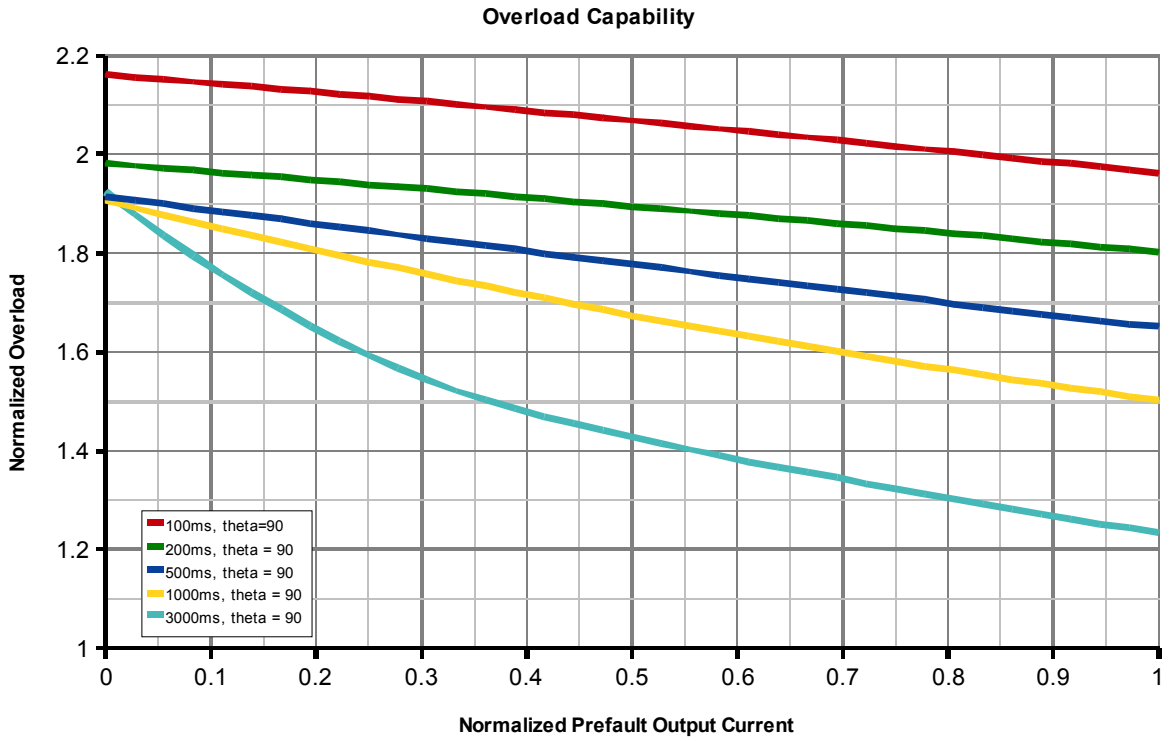


Figure 3-46: Average dynamic overloading capabilities of studied modules (theta = 90°)

The above mentioned plot allows drawing several valuable conclusions: First of all, as probably expected, the overloading capability when injecting pure active current (theta=0 curves) is lower than the one when injecting pure reactive power (theta=90), this has to do with the fact that when injecting pure reactive current, the diode and IGBT losses are more or less equally distributed between both components.

The second, equally important conclusion regards the influence of the pre-fault steady state current. As it was expected, when the inverter injects a small current, the temperatures of the components are low, which allows them to drive a higher current, being the transistor's bodies and the heat sink an energy storage. The effect is of course much more drastic, the longer the fault is. One can also clearly see that at faults over around 500ms, the module is not acting anymore as the energy storage and the heat sink begins to act. This can be due to the settling times of the modules which range from 200ms up to 500ms.

The third and last conclusion is related to the duration of the fault. As already explained, the power module's settling times range from 200ms up to 500ms, after this range, the pre-fault current will play a larger role for increasing overloading times. For times below the ones mentioned, the module will provide enough buffer and the dependency will be more or les maintained.

If we plot the overcurrent characteristic for a given pre-fault current, we end up with Figure 3-47. This plot shows the overload capability at both pf=1 and pf ~ 0 as a function of the fault duration. Since this curve is most of the time dependant on the settling time of the heat sink, the ordinate axis has been normalized to the heatsink's time constant.

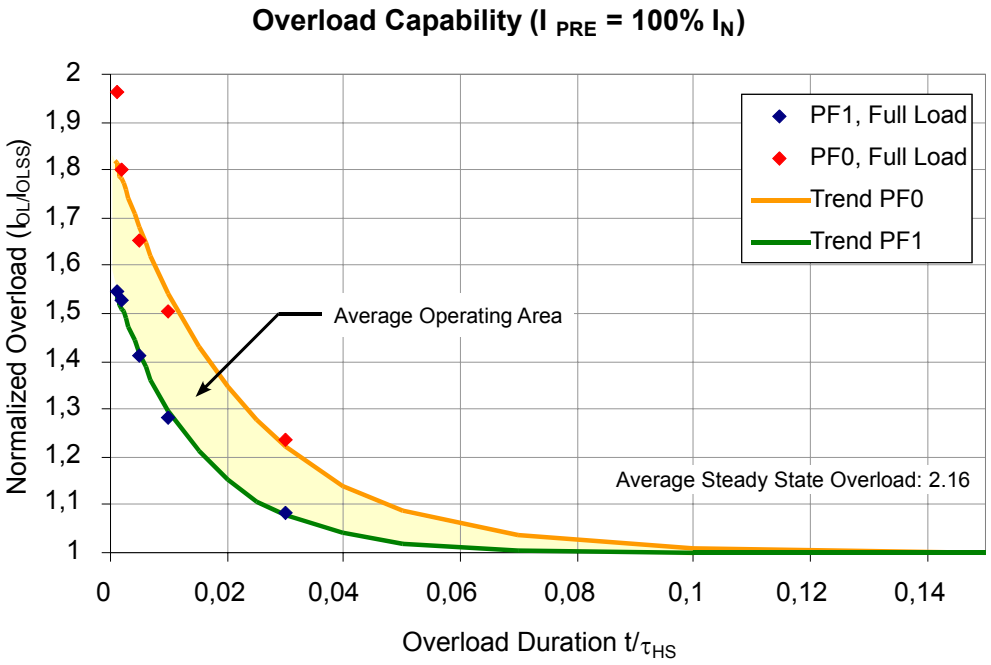


Figure 3-47: Dynamic overloading capabilities of studied modules at a given pre-fault state

It can be seen that even in the worst case (prefault current = 100% nominal current), a good overloading capability is achievable. Using the average steady-state overloading of 2.16, the converter may provide current up to 330%I_N for 100ms if driven at unity power factor or up to 400%I_N if driven with a power factor of 0. It is worth noting that these graphs are highly dependant on the power module. The nominal standard deviation of the data plotted here is of around 0.2. This information provides the general trend but no specifics.

3.8. Conclusions

Due to their inherent degrees of freedom, inverters can comply with desired fault ride through regulations and even exceed some of the expectations. The only bottleneck is the amount of current that the units are able to supply. This is mostly dictated by the semiconductor characteristics.

Regarding the control strategy, it has been found that, while emulating a synchronous generator is the most direct manner of implementing Fault-Ride-Through capabilities in an inverter, it does not exploit the full potential of inverter control and, as it has been shown, the DC-Link capacity must be largely enhanced. Since capacitors have a lower Mean Time To Failure than most other components, the use of more capacity may impact in the reliability of the inverter negatively.

The Delta IARC strategy provides an optimal control of active and reactive power at the cost of higher harmonic contents. Up to some limits, this technique can allow injection of the full power into the grid, thus drastically reducing the use of dump loads or choppers. The impact of the peak-to-rms proportion in both the voltage support process and the loading of the inverter are worth analysing but out of the scope of this work.

In general, the Delta IARC Strategy may be a competitive one if it can be controlled, for example, to allow certain active and/or reactive power oscillations or to allow certain power reduction, if it is to improve the THD of the injected current.

A combination with other strategies that predominantly inject sinusoidal currents may be possible and could bring some of the advantages of the Delta IARC.

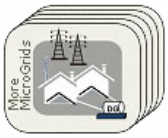
The PNSC shows promising properties such as the fact that the complete active power may be yet injected with sinusoidal currents. Nevertheless the reactive power oscillations and specially the fact that not all lines produce reactive power may not be welcomed by network operators.

With the help of simulations it has been found that the control provides satisfactory results in the simulation validation. The harsh reaction of the sequence component recognition should be however optimized. An input filter may be sufficient but further study is required. The adjustment of active and reactive current offers no problem and can be done in the range of 1 cycle.

The study of the thermal properties of inverter modules yielded that, in average, the inverter is able to supply up to 400% of its design current in the worst operating case. This figure is of course dependant on several factors such as the pre-fault steady state power, the duration of the fault and the design of the heat sink.

It was however found that the influence of the heat sink can be considerable for fault durations of over 200-500ms, where the thermal capacity of the module has been depleted.

It has also been shown, that there is a negative trend of increasing steady state overload capability in terms of normalized efficiencies, meaning that the efficiency at part load is decreased. Among the most direct reasons lies the fact that switching losses are normally augmented with incrementing transistor rating. Solutions such as decreasing switching frequency may help to reduce this effect at the cost of having a larger and heavier converter.



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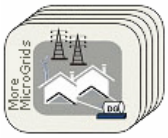

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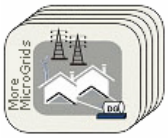

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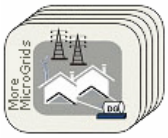
List of Abbreviations

AC	Alternating Current
AGC	Automation Generation Control
CCHP	Combined Cooling, Heating and Power
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
DC	Direct Current
DFIG	Doubly-Fed Induction Generator
DG	Distributed Generator / Distributed Generation
DNO	Distribution Network Operator
DWD	Deutscher Wetterdienst
EHV	Extra High Voltage
EMF	Electromagnetic Force
EN	European Norm
EU	European Union
f	Frequency
FC	Full Converter
FRT	Fault-Ride-Through
HV	High Voltage
IARC	Instantaneous Active-Reactive Control
ICT	Information and Communication Technology
IEC	International Electrotechnical Commission
IGBT	Insulated-Gate Bipolar Transistor
IG	Induction Generator
ISET	Institut für Solare Energieversorgungstechnik
LFC	Load-Frequency Control
LV	Low Voltage
LVDN	Low Voltage Distribution Network
MPP	Maximum Power Point
MV	Medium Voltage
MVDN	Medium Voltage Distribution Network
NRMSE	Normalized Root Mean Square Error
P	Active power
PCC	Point of Common Coupling
PAFC	Phosphoric Acid Fuel Cell
PEFC	Polymer Electrolyte Fuel Cell
PNSC	Positive-Negative Sequence Control
PV	Photovoltaic
Q	Reactive power
R	Resistance
RES	Renewable Energy Sources
RMS	Root Mean Square
RMSE	Root Mean Square Error
SG	Synchronous Generator
SOFC	Solid Oxide Fuel Cell
STATCOM	Synchronous Static Compensator
SVC	Static Var Componeators
THD	Total Harmonic Distortion
TNO	Transmission Network Operator
TSO	Transmission System Operator



U, V	Voltage
UCTE	Union for the Co-ordination of Transmission of Electricity
VSI	Voltage Source Inverter
WTG	Wind Turbine Generator
X	Reactance