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Germany's New Code for Generation Plants connected to Medium-Voltage Networks and its Repercussion on Inverter Control

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Abstract. This paper offers an overview of Germany's new code for generation plants connected to medium-voltage networks. It describes the most important requirements and how inverters may implement most of them without excessive changes in hardware. The analysis is based on the three-phase B6-topology voltage source inverter controlled by a Space Vector Modulation technique.

Keywords

Fault-Ride-Through, grid inverter, distributed generation, grid codes.

1. Introduction

In the past years, the amount of grid-connected generation based on renewable energy sources has increased to a point where it is not negligible anymore. Due to its nature, this type of generation is not only geographically dispersed but also distributed across several voltage levels. These new generation units, together with small and medium sized Combined Heat and Power units (CHP) rapidly became known as Distributed Generation (DG).

As DG began to grow, Utility companies began to have problems handling the increasing amount of uncontrolled generation up to the point where significant security-of-supply risks arouse. One of the most important problems was the fact that DG was not required to provide the robustness and service that conventional generators were obliged in order to maintain a certain power quality level [1].

Standards such as VDE's 0126-1-1 [2] were designed to assure the security of the end user, to protect the generator and to make sure that the unit would not significantly affect the power quality levels at the point of connection.

Nevertheless, the first considerable repercussions of this "unplanned" connection of DG arrived with large wind farms that began connecting to the transmission level. A well known planning criterion is commonly known as "N-1", which dictates that the transmission network must continue working even if a failure of one of its components fails. Under normal circumstances, a fault of, let's say, a transmission line would be isolated by the installed protections and the system would continue its normal operation. Nevertheless, during the fault some of the grid's parameters may be drawn outside their nominal values.

But the wind park was designed to operate only under nominal conditions and suddenly a contemplated N-1 fault became a fault aggravated by the loss of generation of all neighbouring wind parks.

As a response to this Germany's transmission network operators launched in 2004 the Transmission Code, which began to describe the minimum requirements for generation systems connected to transmission networks.

As the amount of generation in the medium voltage distribution levels increases, it has become important to define a similar set of rules for the operation of DG in these voltage levels.

For this effect Germany's Federal association for the management of energy and water (bdew) has published in June 2008 a new code for the connection and operation of generation plants connected to medium voltage networks [3], which aim is exactly this: The effective integration of DG into the network structure on the MV distribution levels.

This new code, of course affects market sectors that were practically unaffected by the Transmission Code: Medium-sized CHPs, large PV plants, small wind parks, etc.

The objective of this work is to provide an overview of the most important requirements, the scope of the new code and how both can affect the design of inverters (an example of a B6 inverter will also be given).

2. Overview of Germany's New Code

Germany's new code for generation plants connected to medium-voltage networks has been completed in June 2008 and will come into effect on January 1st, 2009 [3]. The new code is one of the efforts of system operators towards the integration of large amount of distributed generation (DG) into the network.

A. Scope

The code is to be fulfilled by all generation plants that are to be connected through the medium-voltage distribution level either direct or through a dedicated transformer.

This scope includes some generation units, which are typically connected to the low-voltage level such as PV inverters if they are clustered to achieve larger power levels (such as megawatt PV plants).

Figure 1 shows a typical example of an inverter-based generation plant which has to comply with the new code. Whenever the installed power requires the use of a dedicated MV transformer, the whole plant must be able to comply with the code.

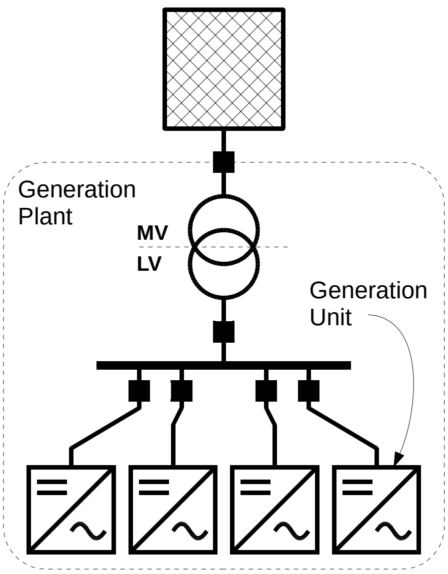

Fig. 1: Example of a generation plant connected to the medium voltage network composed of several generation units on the low voltage network.

B. Plant's Repercussion on the Grid

The code describes the maximum interference levels that generation plants are allowed to produce. These limitations have the objective of assuring the required power quality levels and avoiding device interference. The code defines the following rubrics:

Fast Voltage Changes → Changes produced by the connection and disconnection of one or several units in the plant.

Long-time Flicker → Mostly produced by a very fast change (in the range 8-10Hz) in the primary energy source (e.g. Wind).

Harmonics/Interharmonics → High-order frequency components in the injected current.

Commutation Dips → Voltage dips or notches related to grid-switched devices like thyristor-based inverters.

Audio-frequency remote control → Interference with the operator's audio frequency remote control system (e.g. street lighting)

C. Behaviour of the Plant when connected to the Grid

As said before, in order to effectively integrate DG into the grid, units should be able to contribute to the stability of the grid. The code's requirements in this rubric are presented below:

Static Voltage Support

When the system operator requires it, generation plants must be able to participate in the static voltage support in order to compensate for slow voltage variations and maintain the voltage under permissible voltage levels.

Dynamic Voltage Support

All generation plants are required to provide dynamic voltage support (support under fault conditions), which means that generation plants must:

- Be able to remain connected to the grid during the presence of a fault.
- Be able to help in the voltage support process during the fault by injecting lagging reactive current in the grid.
- Not consume more reactive power after the fault than before the fault occurred.

Figure 2 shows the requirements regarding the first point. As it may be seen, the plant must remain connected to the grid and inject reactive power during the first 150 ms of *any* fault.

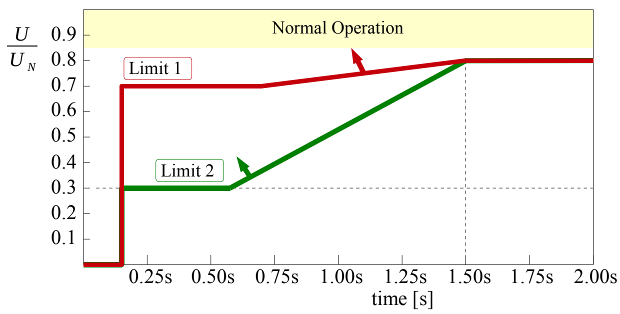

Fig. 2: Fault ride through requirements for generation units which are not based on direct-coupled synchronous machines.

For longer faults, the plant must remain connected for fault over the limit line 2 and must inject reactive power for faults over the limit line 1[1].

The required reactive current in terms of dynamic voltage support is defined as shown in Figure 3. It requires an injection of 90° lagging current, which depends on the minimum voltage. Nominal current should be injected for faults having residual voltages of less than 50% U_N. Voltages in the normal operation area do not require any dynamic voltage support characteristic.

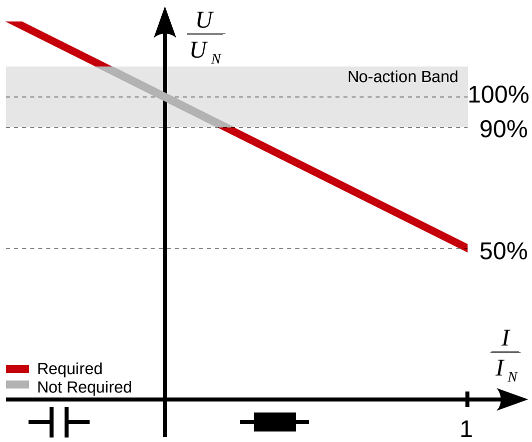

Fig. 3: Reactive current injection requirements

Active Power Throttling

In the case of any potential dangers regarding the stability of the system, the network operator must be able to reduce or even disconnect the generation plant. For this purpose, the plant must provide means for reducing its output power. The active power throttling must be implemented in the following two manners:

- Manually, by using a control signal which is to be given by the Network operator.
- Automatically when detecting an overfrequency.

The reduction must be implemented in a maximum of 10% steps from 100% to 0% of the contracted power. The generation plant must be able to remain connected to the grid for any setpoint over 10%.

The automatic throttling is to be implemented as depicted in Figure 4. In this case, the active power reduction is not a proportion of the contracted power but of the power injected before the overfrequency has been detected.

The automatic throttling should be reduced with a slope of 40%/Hz of the last power value where the frequency was less than 50.2 Hz. The power is also not allowed to increase unless the frequency exhibits a value of less than 50.05 Hz.

[1] Reactive power injection between the two limit lines should be arranged with the system operator

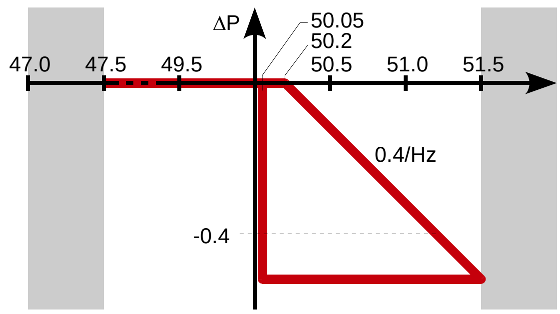

Fig. 4: Allowed frequency operating area and automatic active power throttling requirements.

Reactive Power

As stated before, the generation plant is to participate in the static voltage support process. For this several requirements regarding reactive power injection capabilities have been outlined.

The generation plant must be able to set at least a power factor of 0.95 (both, leading and lagging) for all its power levels.

In addition, the system operator must be able to give a signal for controlling at least one of the following control schemes:

- A fixed power factor cos(φ)
- A displacement factor cos(φ) = f(P)
- A fixed reactive power value Q
- A Voltage regulation characteristic Q = f(U)

D. Protection

Finally, the code presents the requirements for the protection, measurement and decoupling installation. Since these do not really affect the design of the generation units, it is considered out of the scope of this paper.

3. Inverter-based Distributed Generation

The new requirements present manufacturers of DG units with several challenges that were not contemplated before and which, in some cases, may require deep changes in the design.

As presented before, in some cases, even inverter-based generation connected through the low voltage level as in the case of PV, small CHP and small Wind configurations based on the full-converter concept are not exempt of these challenges. They may however overcome most of the requirements with modest efforts.

This work analyses a simple but common converter topology: the B6-Bridge Voltage Source Inverter (VSI). A diagram of the topology is shown in Figure 5.

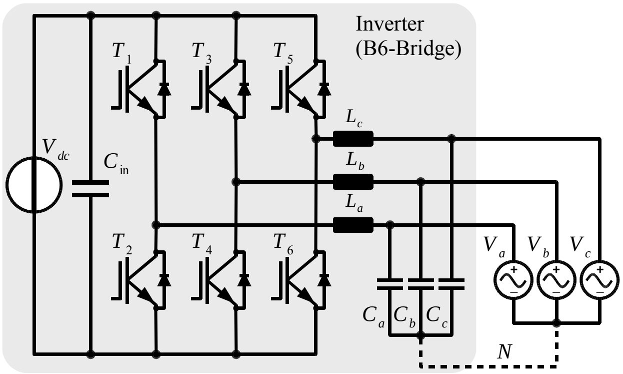

Fig. 5: A classic B6-Bridge VSI with a voltage input source.

This converter topology can –in principle– cover most of the requirements stated in the code through changes in the control structure.

4. Three-phase Inverter Control

Although there is a considerable amount of inverter topologies and control methodologies, this paper will focus on one of the most generally used: The Space Vector Modulation (SVM). As explained by Leon in [4],

> Space Vector Modulation (SVM) where the reference vector, generated by an external control strategy, is represented in a vectorial diagram and is composed as a linear combination of the possible state vectors of the power converter. Nearest Three Vectors (NTV) technique is normally used in three-phase systems determining the three nearest vectors to the reference one [5][6]. These vectors are used in the switching sequence to compose the reference vector and the duty cycles are calculated using geometric expressions.

With this approach, the control may be decoupled from the actual modulation, which largely simplifies the design of the inverter's control loops. Figure 6 shows a traditional SVM-based control.

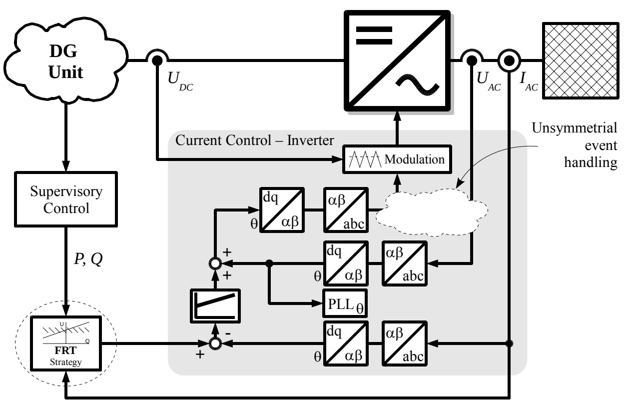

Fig. 6: SVM Control.

A. Implementing Static and Dynamic Voltage Support

The dotted areas in Figure 6 show the sections in the control structure in which the code's requirements regarding static and dynamic voltage support may be implemented. The first section is the input of the setpoint values for the current control. Since the current control already controls active and reactive power (reactive power is usually controlled to be 0), an enhancement does not require any hardware change –other than communication– for implementing static voltage support.

The dynamic support should include an implementation of Figure 3 and an algorithm for the handling of unsymmetrical faults. Several control strategies for the handling of unsymmetrical fault events may be found in [7] and [1]. Although in some of the cases no hardware changes are required, it is likely that an enhancement of the DC-Link capacity is necessary.

Since the unit must ride through faults of values down to zero, it is probable that generation units, which auxiliary power supply (APS) is connected to the grid, do not ride over some of the faults. To prevent this, the APS should provide enough buffer capacity or be derived from the DC-Link.

B. Implementing Active Power Throttling

Most of the time, the SVM Strategy requires information about the electrical angle in order to select the required pulse pattern. This measurement is carried out by a phase-lock loop (PLL) derived from the grid's voltage. The strategy the current frequency of the system as part of the control loop [8].

Since the frequency is already measured, the automatic power throttling may be implemented by modifying the supervisory control (Fig. 6) for reading the frequency and reacting accordingly. The signal required for controlled active power throttling may also be given at this level.

5. Conclusions

Germany's new medium voltage code aims to an effective integration of distributed generation into the current network structure; in which DG is not seen as a threat but as a helpful ally for providing the habitual power quality level. Because of its characteristics it is likely to have a repercussion on several other countries in and outside the European Union.

Inverters, as an important part of distributed generation are also affected by the new rules, which pose several challenges to inverter manufacturers. A review shows that there are mainly two areas that affect inverter manufacturers: Interference levels and Interaction with the grid.

Interference levels may be solved almost exclusively by hardware changes; however, manufacturers have these usually under control. *Interaction with the grid* issues are mostly software requirements but in many cases they may be implemented without a significant change in the hardware nor the control structure.

This paper discussed the most important new requirements and how a simple, yet commonly-used inverter topology may cope with them without requiring an excessive hardware redesign.

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