Response of Low Voltage Networks with High Penetration of Photovoltaic Systems to Transmission Network Faults[1]

K. Skaloumpakas*, J.C. Boemer*, E. van Ruitenbeek*, M. Gibescu*†, M.A.M.M. van der Meijden*

** Delft University of Technology, The Netherlands, e-mail: J.C.Boemer@tudelft.nl,*
†Eindhoven University of Technology, The Netherlands, e-mail: M.Gibescu@tue.nl

Keywords: Power system stability; network fault response; low voltage ride-through; photovoltaic systems; grid codes; dynamic network support; voltage support.

Abstract

The installed capacity of photovoltaic (PV) systems connected to low voltage (LV) networks in Germany has increased to more than 25 GW. Current grid codes still mandate these PV systems to disconnect in case of voltage dips below 0.8 p.u. The resulting response of LV distribution systems with high penetration of PV systems to faults in the transmission network is investigated for an integrated power system model that comprises all relevant voltage levels. Sensitivity studies with respect to the pre-fault power flow, various steady state and fault ride-through (FRT) control modes were performed. Our simulations for a realistic 2022 scenario show that a lack of FRT capability can cause the distribution system load to increase by 35-70 % of its peak value. It was found that for underexcited operation of PV systems prior to the fault, an overvoltage can occur post-fault at some busbars in the distribution system. Therefore, we conclude that new LV-connected PV systems and other DG installations should be requested to perform FRT.

1 Introduction

The installed photovoltaic (PV) capacity in Germany at the beginning of 2013 was more than 32 GWp [1]. More than 25 GW are connected to low voltage (LV) networks [2]. Current grid codes still mandate these distributed generators (DG) to disconnect in case of voltage dips below 0.8 p.u.

Problems similar to the potentially massive disconnection of PV systems in Germany and other EU member states in the Continental Europe (CE) region due to unfavourable frequency protection settings [3] must be avoided by all means. Hence, a need for investigations of fault ride-through (FRT) and related requirements for LV connected DG has been identified worldwide [4–6].

For Germany, the institution responsible for the development of grid connection requirements (GCR)—the Forum network technology / network & operation (FNN) in the German Association for Electrical, Electronic & Information Technologies (VDE) —initiated a study on the adequacy of the latest grid connection requirements (GCR) for LV connected DG [7].

2 Problem definition & Objective

The current FNN application guide for small-scale DG at LV networks (VDE-AR-N 4105) does not require LVRT [8]. On the contrary, it requires all small-scale DG at LV networks to disconnect within 200 ms if the voltage at their terminals drops below 0.8 p.u.. Figure 1 suggests that already today about 4 GW of PV capacity is installed in the area where retained TS voltage is close to that threshold for the shown voltage dip approximated from [2, 9].

Therefore, the objective of this paper is to investigate the response of low voltage distribution systems with high penetration of PV in case of a fault in the transmission system for various steady state and FRT control modes.

To this end, these research questions are formulated:

- If current GCR remain unchanged, how much active power in-feed from LV connected PV systems could be lost due to a transmission system fault in a worst case 2022 scenario?

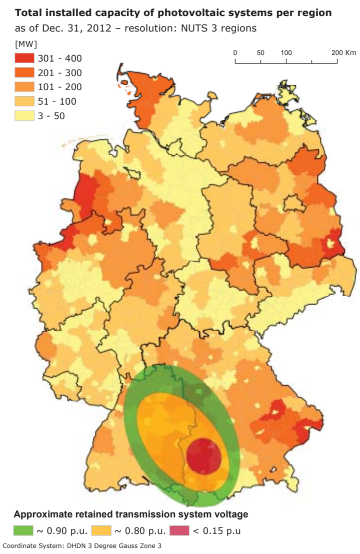


Figure 1: Assessment of voltage dip based on [2, 9]

[1] This paper presents selected results from reference [10].

- What other risks in addition to loss of active power can be identified?
- How should new LV connected PV systems behave during transmission system faults to maintain system stability?

3 Methodology

The problem is analysed in the time domain with stability-type (RMS, positive sequence) simulations for a three-phase fault in the transmission network. The fault occurs at t = 0 s and is cleared 150 ms later. The target year for this study is 2022 and respective assumptions regarding the rated DG penetration levels (based on peak load) are derived from [9].
An integrated power system model that comprises all relevant voltage levels is used although this results into a high degree of complexity. This choice is motivated by the hope to show dynamic interactions between the distribution and transmission levels which would otherwise have to be neglected (e.g. post-fault voltage oscillations caused by synchronous machines at eHV level combined with a substantially changed voltage profile in the post-fault period). Furthermore, the approach allows for studying of system-wide effects with aggregated active distribution systems at a later stage.

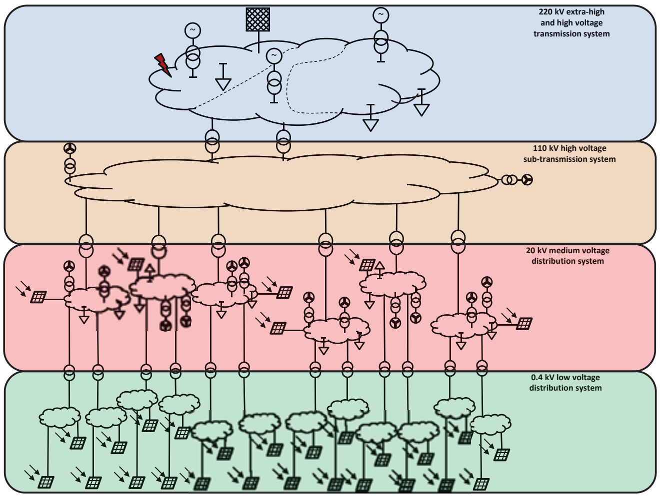


Figure 2: Structure of the test system [10]

3.1 Test system

The structure of the test system is presented in Figure 2. A single extra-high voltage (eHV) 220 kV network (blue) connects to a single high voltage (HV) 110 kV ring network (orange) at one connection point via two eHV/HV transformers. The HV ring network connects to six identical medium voltage (MV) radial networks (red). Low voltage (LV) networks (green) are connected at two locations in the MV networks, one close to and the other far from the HV/MV transformer. The former represent 38 LV networks in an aggregated way (parallel elements).
Each voltage level encompasses various types of elements including synchronous generators, loads and distributed generation (DG). Loads are present in all voltage levels whereas synchronous generators are only placed at the eHV network. Wind power plants are placed in the HV and MV networks and PV systems in the MV and LV networks. The PV systems are connected to the LV networks either close to or far from the MV/LV transformer to account for different X/R ratios at their connection points (X/R = 4.4 versus 0.4).

The eHV network is a DIgSILENT PowerFactory model of the 39-bus 10-machines New England network validated by IEEE for stability controlled performance [11]. The HV network is a 110 kV sub-transmission ring implemented according to [12]. For the presented results, Cigré MV and LV distribution benchmark networks are used [13]. In future research, the study results will be compared to results obtained with real distribution networks from a German distribution system operator (DSO). A detailed description on the test system can be found in [10].

The setup of the test system assumes a higher concentration of PV systems at certain LV nodes than it would be expected in reality. However, this allows to analyse certain effects separately which would otherwise blur in real networks.

3.2 Distributed generation modelling

A validated, positive sequence PV system model suitable for stability studies obtained from [14] was extended with new dynamic voltage support controls during FRT mode. Wind power plants connected to MV and HV networks were modelled according to [12].

3.3 PV fault modes

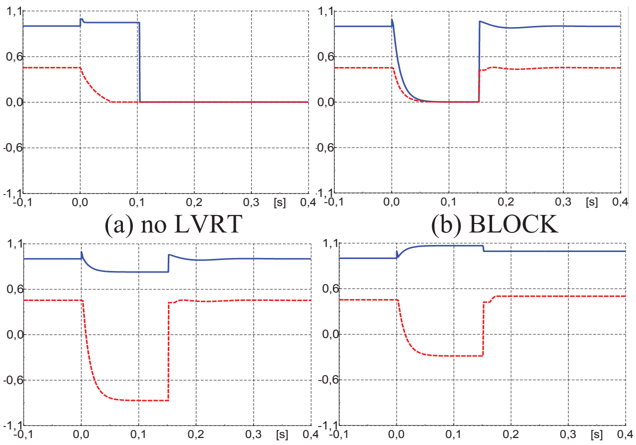
Four different control approaches are used for the PV system during the fault period:

- No-LVRT mode;
- Blocking mode (BLOCK, sometimes referred to as “Zero-Power-Mode”);
- Additional reactive current injection (aRCI);
- Additional reactive & active current injection (aRACI).

The PV system current response (i_d, i_q) to a voltage dip with a retained voltage of V_{ret} = 0.3 p.u. is shown for each of these modes in Figure 3. At an in-feed larger than 0.5 p.u, the PV system is operating with inductive power factor and exchanges reactive power with the network pre-fault as required by [8]. Further details on the control modes can be found in [10].

Figure 3a shows the response of the PV system for the no LVRT mode which represent the nowadays GCR for LV connected PV system. When the voltage at the PV terminal drops below a value of 0.8 p.u., the protection relay disconnects the PV from the network within 0.1 s. This value has been chosen to fulfil the GCR of a disconnection within a maximum of 0.2 s. The no LVRT mode is used for 50 % of installed PVs, assuming that this fraction of PV capacity was installed prior to 2022 and therefore has no LVRT capability. The rest of the PV capacity can enable any of the three remaining control modes.

Figure 3b shows the response of the PV system for the blocking mode (BLOCK). This control mode is desired for 90 % of all MV connected DG by German distribution system operators (DSO) to avoid conflicts of DG with network protection [15]. When the voltage at the PV terminal drops below a value of 0.9 p.u., the PV system stays connected during the voltage dip but ceases to inject any active and reactive power into the network. As soon as the voltage is restored, the active power of the PV system would be ramped up to the pre-fault value with 20 % of rated active power per second [16, 17] . However, in a first step, an immediate power recovery is assumed and the differences resulting from a delayed power recovery after fault are studied in a second step.



(a) no LVRT (b) BLOCK (c) aRCI (d) aRACI

Figure 3: d-axis (blue) & q-axis (red) currents of PV inverter for a reactive/active current gain k = 2 p.u. and a voltage dip with a retained voltage of V_{ret} = 0.3 p.u. [10]

Figure 3c shows the response of the PV system for the additional reactive current injection mode (aRCI). When the voltage at the PV terminal drops below a value of 0.9 p.u., the PV system stays connected during the voltage dip and injects a reactive current in addition to the pre-fault set-point and in proportion to the voltage dip at its terminals. The reactive current gain is set to k = 2 p.u. in this case.

Figure 3d shows the response of the PV system for the additional reactive and active current injection mode (aRACI). The response is similar to the aRCI mode but with the difference that the additional current injected is a combination of a reactive and active current in addition to the respective pre-fault set-points. The ratio between the additional active and reactive current components is set equal to the angle of the network impedance seen from the PV system's terminals.

4 Results and analysis

Three different pre-fault power flow situations were investigated in [10]. From these results, only the ones for the normal and for the reverse power flow (RPF) are presented here. In the RPF situation, the active power is exported from the LV level through the MV and HV level to the eHV network. PV systems connected to LV level are operating with inductive power factor to keep their terminal voltage within the admissible voltage band, hence, exchanging reactive power with the network pre-fault. In the normal power flow (NPF) situation, PV systems operate at unity power factor and do not exchange reactive power with the network pre-fault.
The results are further differentiated between PV systems connected close to the MV/LV transformer where the network impedance is predominantly inductive (X/R = 4.4) and other PV systems connected to the end of the LV feeder where the network impedance has a high resistive part (X/R = 0.4).

4.1 Active power in-feed from DG lost post-fault

Figure 4 shows the active power response of the LV connected PV systems that are connected close to the MV/LV transformer for the NPF situation. Due to the aggregated representation of the related LV networks and their PV systems, the base value for the per unit values is 4 560 kVA. In this NPF case, the PV systems generate 0.5 p.u. active power pre-fault while the loads are at their peak values. The active power drops sharply when the transmission system fault occurs in proportion to the retained voltage of approx. 0.45 p.u. In the first 100 ms of the fault, the active power increases by about 0.05 p.u. due to the dynamic voltage support from MV connected PV systems and wind parks. Then, the PV systems disconnect and their active power remains zero post-fault. The results for the various cases have shown that the disconnection of existing and new PV systems can cause the distribution system load to increase by 35-70 % of its peak value within less than 200 ms if the current GCR remain unchanged in the future.

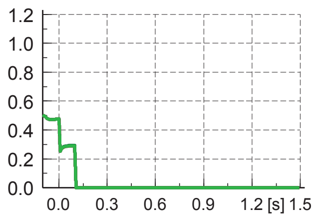
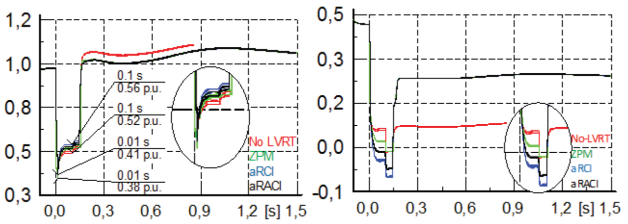


Figure 4: Active power output [p.u.] of all LV connected PV systems connected close to the MV/LV transformer (X/R = 4.4) – normal power flow and operation of PV systems at unity power factor pre-fault; base value for per unit values is 4 560 kVA [10]

4.2 Influence of FRT control mode for reverse power flow

Figure 5a shows the voltage at the terminals of the PV systems that are connected close to the MV/LV transformer in the RPF situation for the four different FRT control modes. The PV systems are operated with inductive power factor pre-fault. The X/R ratio of the network impedance at the respective connection points is 4.4.

The voltage drops to 0.41 p.u. at the moment of fault occurrence for all control modes except for the BLOCK mode (**green** line) where it drops to 0.38 p.u. Following the voltage dip and during the first 100 ms of the fault the voltage rises to a value between 0.52 p.u. (no-LVRT, **red** line) and 0.56 p.u. (aRCI, **blue** line). The differences between the FRT control modes are small but the enlarged part of the figure shows that the effectiveness of dynamic voltage support is highest for aRCI, followed by aRACI (**black** line), then BLOCK mode and then the no-LVRT mode. The results confirm that injecting reactive power during the fault (aRCI) is very effective at connection points with a X/R ratio of larger than one. The maximum achieved voltage support is 0.15 p.u. in this case.



(a) voltage [p.u.] at PV terminals close to the MV/LV trafo

(b) reactive power [p.u.] over a MV/LV trafo base value 500 kVA

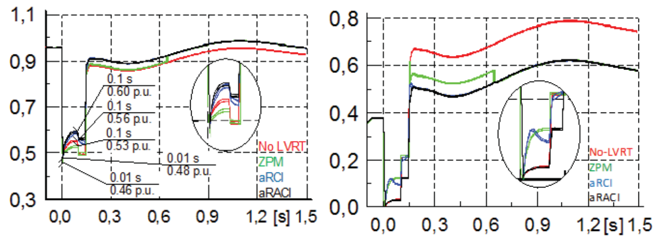
Figure 5: Influence of FRT control mode – reverse power flow and operation of PV systems with inductive power factor pre-fault; [10]

After the first 100 ms of the fault, the disconnection of the LV connected PVs is results in a voltage rise for all FRT control modes. While this might be surprising at first sight, a closer inspection of the reactive power exchange over a MV/LV transformer, as shown in Figure 5b, reveals that this can be explained with a significant change in the reactive power flow over the transformer at the instance of when PV system disconnect. The inductive pre-fault reactive power consumed by the PV systems which were connected to the network before the study year 2022 is lost at t = 100 ms and the 'excess' of reactive power in the network leads to a raise in the terminal voltage. The effectiveness of the four FRT control modes w.r.t. dynamic voltage support remains unchanged in the 50 ms time period that follows.

At fault clearance, the PV terminal voltages recover instantaneously to a value that is higher than the pre-fault value. With no-LVRT control mode, a significant and sustained overvoltage can be observed in the post-fault period in Figure 5a. The voltage can actually reach a value of 1.1 p.u. in certain MV nodes of the benchmark system which triggers MV connected PV systems to switch into high voltage ride-through (HVRT) mode but may also cause tripping of loads. The simulations were stopped at this point because results for the following time steps were regarded as invalid. The overvoltage observed for the no-LVRT mode is consistent with the significantly lower value of reactive power flow over a MV/LV transformer as shown in Figure 5b. The BLOCK mode and the aRCI/aRACI control modes show a much smaller difference in the pre- and post-fault reactive power flows and, therefore, the post-fault overvoltage is also less pronounced in these cases.

4.2 Influence of FRT control mode for normal power flow

Figure 6a shows the voltage at the terminals of the PV systems that are connected to the end of the LV feeder in the NPF situation for the four different FRT control modes. The PV systems are operated at unity power factor pre-fault. The X/R ratio of the network impedance at the respective connection points is 0.4.



(a) voltage [p.u.] at PV terminals at the end of the LV feeder

(b) active power [p.u.] over a MV/LV trafo base value 500 kVA

Figure 6: Influence of FRT control mode – normal power flow and operation of PV systems at unity power factor pre-fault. [10]

The voltage drops to 0.48 p.u. at the moment of fault occurrence for all control modes except for the BLOCK mode (**green** line) where it drops to 0.46 p.u. Compared to the PV systems close to the MV/LV transformer, the aRACI mode (**black** line) proves to be slightly more effective than the aRCI mode (**blue** line) by increasing the voltage up to 0.6 p.u. An additional difference is that the no-LVRT mode (**red** line) proves to be more effective (reaching 0.56 p.u.) than the BLOCK mode (reaching only 0.53 p.u.). Both observations are supported by the fact that injection of active current supports the voltage more effectively than injection of reactive at connection points at the end of the LV feeders due to the low X/R ratio of 0.4. The maximum voltage support is 0.12 p.u. in this case while the lower value is only 0.07 p.u.

After the first 100 ms of the fault, the disconnection of the LV connected PV systems results in a voltage drop for all FRT control modes. This is the opposite behaviour compared to the reverse power flow situation. A closer inspection of the active power exchange over a MV/LV transformer, as shown in Figure 6b, reveals that this can be explained with a significant change in the active power flow over the transformer at the instance of when PV system disconnect. When the in-feed from the PV systems which were connected to the network before the study year 2022 is lost at t = 100 ms, significantly more active power must be imported from the MV network. Due to the low X/R ratio, this causes an additional voltage drop toward these connection points at the end of the LV feeders.

At fault clearance, the PV terminal voltages recover instantaneously to a value that is lower than the pre-fault value. This is again the opposite behaviour compared to the reverse power flow situation. With no-LVRT control mode, a significant and sustained undervoltage can be observed in the post-fault period in Figure 6a. The undervoltage observed for the no-LVRT mode is consistent with the significantly higher value of active power flow over a MV/LV transformer as shown in Figure 6b. The aRCI/aRACI control modes show a much smaller difference in the pre- and post-fault active power flows and, therefore, the post-fault undervoltage is also less pronounced in these cases.

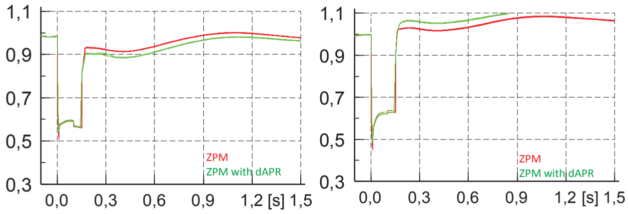
However, the results for the BLOCK mode exhibit a temporary undervoltage similar to the no-LVRT mode but limited to t = 0.63 s. At that moment, the voltage rises to the value of the aRCI/aRACI control modes again. This can be explained by that the terminal voltage does not recover into the normal operating band of 0.9–1.1 p.u. at the moment of fault clearance because the PV systems ceased to exchange any active power during the BLOCK mode and the missing active power must be imported from the MV system at the costs of an additional voltage drop at the end of the LV feeders. Hence, the PV systems connected there do not switch from FRT back to their normal operating mode; their FRT operation is actually prolonged for about 0.5 s. A prolonged FRT operation might be unacceptable for a power system with low inertia.

From these results it can be concluded that the no-LVRT and BLOCK modes bear the risk to cause a post-fault undervoltage at nodes in the LV network that are located towards the end of the LV feeder and have a X/R ratio of smaller than 1. This findings suggests to demand from LV connected PV system to provide a dynamic voltage support such as aRCI or aRACI during FRT mode. However, such a GCR would have a high impact on the protective system prevalent in the respective LV network. The protective system might actually have to be revised in order to prevent blinding and false tripping of protective devices.

4.2 Influence of delayed active power recovery post-fault

Figure 7 shows the voltage at the terminals of certain PV systems in a NPF, respective RPF, situation for the BLOCK mode either with (green line) or without (red line) delayed active power recovery (dAPR). With dAPR, the active power of the PV system is ramped up to the pre-fault value with 20 % of rated active power per second [16, 17] . Results for aRCI and aRACI control modes are not shown because it turned out that the active (d-axis) current of the PV systems was not lower at the moment of fault clearance than pre-fault for the particular transmission system fault investigated. This is a condition to show the influence of dAPR.

The general effects are similar to the previously described observations. For PV systems located towards the end of the LV feeder, the results shown in Figure 7a for a NPF situation indicate that a dAPR further deteriorates the post-fault restoration of the voltage. For PV systems located close to the MV/LV transformers, the results shown in Figure 7b for a RPF situation indicate that a dAPR further increases the risk of a post-fault overvoltage. Hence, it is concluded that LV connected PV systems should recover their pre-fault active power value as quickly as possible after fault clearance.



(a) at PV terminals at the end of the LV feeder – normal power flow

(b) at PV terminals close to the MV/LV trafo – reverse power flow

Figure 7; Voltages [p.u.] for BLOCK mode with (green) and without (red) delayed active power recovery [10]

5 Conclusions and Recommendations

Current grid codes still mandate PV systems connected to low voltage (LV) networks to disconnect in case of voltage dips below 0.8 p.u. In this paper, the resulting response of low voltage distribution systems with high penetration of PV systems to faults in the transmission network is investigated for an integrated power system model that comprises all relevant voltage levels. Sensitivity studies with respect to the pre-fault power flow, various steady state and fault ride-through (FRT) control modes were performed. The findings from modelling of a realistic 2022 scenario can be summarised as follows.

If current GCR remain unchanged, voltage sags below 0.65-0.73 p.u. retained voltage at transmission level cause the disconnection of non-FRT compliant distributed generation. The range of the retained voltage depends on the voltage support of other, FRT-capable DG at distribution level. A lack of FRT capability of LV connected PV systems can cause the distribution system load to increase by 35-70 % of its peak value within less than 200 ms. When transmission network faults result in widespread voltage sags, in the near future, this would pose a significant threat to the post-fault active power balance. Disconnection of PV systems can create an additional voltage drop during the fault inside the LV network. In some cases, this could cause more DG to disconnect. For inductive power factor operation of PV systems prior to the fault, an overvoltage can occur post-fault at MV busbars as well as at LV busbars that are located closely to the MV/LV distribution transformer. Therefore, requiring a cos(φ)(P) characteristic for static voltage support in grid codes *without* simultaneously requiring a FRT capability should be seriously reconsidered.

To maintain the post-fault active power balance, a minimum requirement for new LV connected PV systems should be to ride through voltage dips caused by transmission system faults in blocking mode (limited dynamic network support) and recover their pre-fault active power value quickly after fault clearance. It should be noted, however, that the blocking mode was found to bear the risk of a prolonged FRT operation for when, under certain conditions, the voltage at the terminals of PV systems connected inside a LV feeder (low X/R ratio) does not immediately recover above the threshold that would trigger the transition to normal operating mode. This finding suggests to demand a dynamic voltage support during FRT mode (full dynamic network support).

To help existing DG installations to run through voltage dips, new PV systems would have to provide full dynamic voltage support during FRT mode. It was shown that the X/R ratio at the PV system terminals determines whether a purely reactive or a combined reactive/active current injection brings the most effective dynamic voltage support. However, even in the best case the voltage increase remained small in the range of 0.07–0.15 p.u. Consequently, any voltage sags below 0.65–0.73 p.u. retained voltage at transmission level would still cause the disconnection of non-FRT compliant distributed generation.

A minimum requirement of full dynamic voltage support for LV connected PV systems would have a high impact on the protective system prevalent in the respective LV network. The protective system might have to be revised in order to prevent blinding and false tripping of protective devices. Given the limited voltage support found in this paper such a minimum requirement remains questionable. Future research will have to assess its value by use of an elaborate power system model that allows for a comparison of the geographical expansion of voltage dips in the transmission system and the capacity of LV connected PV system affected.

Acknowledgements

The Forum network technology / network operation in the VDE (FNN) is greatly appreciated for the funding of this work. We also thank Afshin Samadi for proving us with the base PV system model.

References

[1] German Solar Industry Association (BSW-Solar), "Statistic data on the German Solar power (photovoltaic) industry," Jun. 2013.

[2] Deutsche Gesellschaft für Sonnenenergie (DGS) e.V, *EnergyMap.info: Konsolidierte und plausibilisierte Datenbank der Stammdaten von EEG-Anlagen in Deutschland (Consolidated and plausibilised database of the EEG power plant registry in Germany).* Available: online (February 2013).

[3] ENTSO-E, *Dispersed Generation Impact on CE Region Security: Dynamic Study.* Final Report. Available: online (2013).

[4] IEEE Standards Coordinating Committee 21, *IEEE 1547 Standard for Interconnecting Distributed Resources With Electric Power Systems: Workshop Meeting Minutes, December 3 - 4, 2013, New Brunswick, NJ.* Available: online.

[5] ENTSO-E User Group, *Meeting on "Network Code for Requirements for Grid Connection applicable to all Generators" (NC RfG) on 22 November 2012.* Minutes and Presentations. Brussels. Available: online (2013).

[6] FNN, *VDE|FNN-Roadmap identifiziert weiteren Entwicklungsbedarf zum Umbau der Netze (VDE|FNN-Roadmap identifies further need in the transformation of the electricity network): Press release*. Berlin, 2012.

[7] J. C. Boemer et al., "Response of Low Voltage Networks with High Penetration of Photovoltaic Systems to Transmission Network Faults," in *3rd International Workshop on Integration of Solar Power into Power Systems,* London, U.K, 2013.

[8] *Generators in the low voltage distribution network. Application guide for generating plants' connection to and parallel operation with the low-voltage network*, VDE-AR-N 4105, 2011.

[9] German TSOs, "Netzentwicklungsplan Strom 2012 (Network Development Plan Electricity 2012): 2. überarbeiteter Entwurf der Übertragungsnetzbetreiber (2nd revised draft of the transmission system operators)," German TSOs, May. 2012.

[10] K. Skaloumpakas, "Response of Low Voltage Networks with High Photovoltaic Systems Penetration to Transmission Network Faults," Master thesis, Electrical Sustainable Energy, Delft University of Technology, Delft, 2014.

[11] D. Molina, "Progress report on the development and validation of DIgSILENT PowerFactory model of the 39-Bus benchmark system for stability controls: Addressed to IEEE Task Force on Benchmark Systems for Stability Controls," Georgia Institute of Technology, Sep. 2012.

[12] J. C. Boemer et al., "Fault Ride-through Requirements for Onshore Wind Power Plants in Europe: the Needs of the Power System," in *2011 IEEE PES General Meeting,* Detroit, USA, 2011.

[13] CIGRE Task Force C6.04.02, "Benchmark Systems for Network Integration of Renewable and Distributed Energy Resources: Technical Brochure (unpublished draft)," CIGRÉ, Paris (21 rue d'Artois, 75008), 2013.

[14] A. Samadi et al., "Comparison of a Three-Phase Single-Stage PV System in PSCAD and PowerFactory," in *2nd International Workshop on Integration of Solar Power into Power Systems,* Lisbon, Portugal, Nov. 2012.

[15] "Anschlusspraxis von Erzeugungsanlagen hinsichtlich einer dynamischen Netzstützung (connection practice for generating plants regarding dynamic network support): Interner Bericht der RWE Deutschland AG (internal report of RWE Germany AG)," RWE Germany AG, Essen, Mar. 2014.

[16] Verband der Netzbetreiber - VDN – e.V. beim VDEW (German Association of Network Operators, since beginning of 2008 part of BDEW), *TransmissionCode 2007. Network and System Rules of the German Transmission System Operators,* 1st ed, 2007.

[17] *Requirements for the connection of generators above 16 A per phase - Part 1: Connection to the LV distribution system*, CLC/FprTS 50549-1:2011, 2012.