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International Energy Agency
**Photovoltaic Power Systems Programme**

Task 14 Solar PV in the 100% RES Power System

PVPS

# PV as an ancillary service provider
2021

Report IEA-PVPS T14-14:2021

# What is IEA PVPS TCP?

The International Energy Agency (IEA), founded in 1974, is an autonomous body within the framework of the Organization for Economic Cooperation and Development (OECD). The Technology Collaboration Programme (TCP) was created with a belief that the future of energy security and sustainability starts with global collaboration. The programme is made up of 6.000 experts across government, academia, and industry dedicated to advancing common research and the application of specific energy technologies.

The IEA Photovoltaic Power Systems Programme (IEA PVPS) is one of the TCP's within the IEA and was established in 1993. The mission of the programme is to "enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems." In order to achieve this, the Programme's participants have undertaken a variety of joint research projects in PV power systems applications. The overall programme is headed by an Executive Committee, comprised of one delegate from each country or organisation member, which designates distinct 'Tasks,' that may be research projects or activity areas.

The IEA PVPS participating countries are Australia, Austria, Belgium, Canada, Chile, China, Denmark, Finland, France, Germany, Israel, Italy, Japan, Korea, Malaysia, Mexico, Morocco, the Netherlands, Norway, Portugal, South Africa, Spain, Sweden, Switzerland, Thailand, Turkey, and the United States of America. The European Commission, Solar Power Europe, the Smart Electric Power Alliance (SEPA), the Solar Energy Industries Association, and the Copper Alliance are also members.

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# What is IEA PVPS Task 14?

The objective of Task 14 of the IEA Photovoltaic Power Systems Programme is to promote the use of grid-connected PV as an important source of energy in electric power systems. The active national experts from 15 institutions from around the world are collaborating with each other within Subtask B – Operation and planning of power systems with high penetration of Solar PV and Renewable Energy Sources (RES) – in order to share the technical and economical experiences, and challenges. These efforts aim to reduce barriers for achieving high penetration levels of PV Systems in Electricity Grids.



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**COVER PICTURE**

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INTERNATIONAL ENERGY AGENCY

PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

# IEA PVPS Task 14
# PV as an ancillary service provider - Laboratory and field experiences from different IEA PVPS countries

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# TABLE OF CONTENTS

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# LIST OF ABBREVIATIONS

| | |
|---|---|
| AC | Alternating current |
| APC | Active power curtailment |
| aFRR | Automatic Frequency Restoration Reserve |
| CHP | Combined heat and power |
| CIM | Common information model |
| CLS | Controllable local system |
| DC | Direct current |
| DER | Distributed energy resources |
| DSO | Distribution system operator |
| EDCC | Experimental distribution control center |
| EU | European Union |
| FACTS | Flexible-AC-Transmission-System |
| FCR | Frequency containment reserve |
| GWA | Gateway Administrator |
| HAN | Home Area Network |
| HV | High voltage |
| HVRT (OVRT) | High (over) voltage ride through |
| IBR | Inverter based renewable energy source |
| IEA | International Energy Agency |
| IEC | International Electrotechnical Commission |
| IEEE | Institute of Electrical and Electronics Engineers |
| LV | Low voltage |
| LVRT (UVRT) | Low (under) voltage ride through |
| mFRR | Manual Frequency Restoration Reserve |
| MV | Medium voltage |
| NEM | National electricity market |
| NSHV | Low voltage main busbar |
| NSW | New South Wales, Australia |
| POC | Point of coupling |
| PV | Photovoltaic |
| PVPS | Photovoltaic power systems programme |
| QLD | Queensland, Australia |
| RES | Renewable energy sources |
| RoCoF | Rate of Change of Frequency |

| | |
|---|---|
| RfG | Requirements for generators |
| RTU | Remote terminal unit |
| SA | South Australia, Australia |
| SCADA | Supervisory Control and Data Acquisition |
| SMI | Smart Meter Infrastructure |
| SMGW | Smart Meter Gateways |
| T-D interface | Transmission-Distribution (T-D) interface |
| TSO | Transmission system operator |
| VRE | Variable renewable energy |
| WEO | World energy outlook |

# EXECUTIVE SUMMARY

The PV penetration in many countries is continuously growing and PV is becoming a major energy source in the future electricity grid worldwide. Therefore, PV systems and PV hybrids need to take over more and more system responsibility by providing ancillary services. Ancillary service "means a service necessary for the operation of a transmission or distribution system" [1], such as frequency control, inertia, operating reserve, voltage or reactive power control, and black-start capability. These services can be provided by grid users, such as conventional power plants, renewable energy sources (RES), storage units, or flexible loads, to support or ensure a secure and reliable power system operation. The specifications, types, needs, and procurement procedures of these ancillary services can vary in different power systems and are changing with the progress of the energy transition in many countries.

This report highlights the status and the potential of PV and PV hybrids as an ancillary service provider. The focus is set on mainly good practice examples from different IEA PVPS countries. In addition, improvement and further development potential and needs for the application of PV as an ancillary service provider are also addressed and discussed. The following summary describes the field experiences and lessons learned for different ancillary services provided by PV systems and PV hybrids.

**PV frequency control** – In the future, PV systems can participate in frequency control reserve markets. However, prequalification procedures and product specifications might need to be adjusted to enable PV system participation.

„Frequency control is a set of control actions aimed at maintaining the system frequency at its nominal value" [2]. The frequency control is implemented in different stages, distinguished by different response times and durations, typically primary control, secondary control, and tertiary control. The report provides project and field-tests results from Germany concerning the capability of PV and Wind power plants to provide frequency control services for the German TSOs.

- **Frequency control services by PV power plants (Field test, Germany):** The project indicates that the provision of secondary control reserve and minute reserve using pools of Wind and PV power plants is generally possible and practicable, but depends in detail on the formulation of the accuracy requirements for frequency control reserve markets by the TSOs. For example, shorter tendering periods and shorter product time slices can support the participation of PV systems in these control reserve markets.

Additionally, the grid codes in several countries define mandatory requirements on frequency response behavior of generation units, such as frequency ride-through requirements and a frequency–watt droop function P(f), which can support frequency maintenance in case of a fault event. This report summarizes field experiences and lessons learned from a major system disturbance in Australia in 2018 and the distributed PV response behavior.

- **Distributed PV frequency response to a lightning strike and resulting frequency excursions in Australia, (Field results, Australia):** The report found: "a clear aggregate response of the correct shape and approximate magnitude, suggesting that this designed control response is correctly implemented in some proportion of the PV inverters." However, the report also found non-compliance of around 15% of distributed PV systems, which has led to a subsequent investigation and compliance monitoring.

**PV power curtailment** – PV power curtailment can be an effective and economic measure to achieve a very high PV penetration level in electric power systems. Effective curtailment procedures need to be developed also for residential PV.

PV power curtailment can be an effective measure to increase the PV grid hosting capacity and can support congestion management, voltage control, and power balancing at the transmission and distribution level. Furthermore, curtailed PV may also be a source of operating reserve to manage unexpected changes in net demand. This report presents field test applications of two curtailment practices of residential PV systems, a local dynamic power curtailment, which can minimize PV curtailment losses, and a remote curtailment of residential PV systems via Smart Meter Gateway, which can support congestion management at the distribution level and the upstream transmission level.

- **PV dynamic power curtailment (Field test, Switzerland):** The dynamic PV power curtailment works and is an economic measure to increase the PV hosting capacity of a grid. However, the precision of the controller is limited in the tested device. Therefore, an application of an additional safety margin is recommended to secure compliance with a defined feed-in limitation.
- **Remote curtailment of residential PV systems via Smart Meter Gateway (Field test, Germany):** With Digitalization and the introduction of Smart Grids an effective and economic remote curtailment will also become available for residential PV systems. The C/sells field test demonstrated the use of the Smart Meter Infrastructure for secured, bidirectional communication between PV inverters and a distribution control center. In addition to the curtailment, the Smart Meter Infrastructure also enabled energy market access. With the utilization of the IEC 61850 data model, automatic integration of massive residential PV systems into the distribution control center became possible, reducing the integration effort for RES.

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**PV voltage support** – Besides local voltage support, such as volt-var control, distributed PV can compensate reactive power demands of consumers and can provide reactive power flexibility at the transmission-distribution interface.

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Local reactive power control, such as volt-var control, is increasingly applied for PV inverters in several countries in field applications. The local reactive power control by PV inverters can increase the PV grid hosting capacity. A management summary on local reactive power control by PV inverters is provided in a previous publication by the IEA PVPS Task 14 [3]. Further voltage support services by distributed PV systems, such as reactive power compensation for commercial consumers or reactive power provision for upstream transmission grid operators are addressed in this report.

- **PV local reactive power compensation in a chocolate factory (Field application, Switzerland):** In actual operation, the inverters have demonstrated their ability to compensate the reactive power demand by the production equipment in the chocolate factory according to two types of regulation: either by maintaining a fixed value of reactive power or by maintaining a fixed Q/P ratio.
- **Remote PV reactive power control for voltage support at the Transmission – Distribution interface (Field test, Germany):** A successful field test showed the control of up to 40 MVAr from distributed Wind and PV power plants at the Transmission-Distribution interface. Reactive power provision from distributed energy resources has a significant potential to compensate reactive power demands at the distribution level and to support the voltage regulation also at the upstream transmission level in Germany.

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**PV hybrids in insular power systems** – Proof of concept of grid-forming inverters shown in field applications, but further requirement specifications needed for grid forming inverters.

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A grid-forming inverter describes “an inverter having a control approach with the capability to control the terminal voltage directly and to form the grid voltage purely by inverters under consideration of necessary reserve and storage capacity” [4]. The report provides examples for the successful application of grid-forming inverters in insular power systems and micro grid applications. With the increased penetration of inverter-based generators in electric power systems worldwide, the need for PV hybrids with grid-forming capabilities will also emerge in large interconnected power systems. Therefore, the field applications from insular power systems can provide important lessons learned for the inverter-dominated future of large interconnected power systems.

- **PV storage hybrid system for 100% solar power on the remote island of St. Eustatius (Field application, Netherlands Antilles):** Today's utility-scale grid forming PV storage hybrid systems provide ancillary services that allow a 100% solar power generation and a substitution of Diesel generators in island grids, thereby providing a stable and secure grid operation with a superior power quality compared to public electricity grids.
- **One hour with 100% renewable power - islanding operation test of the German community of Bordesholm (Field test, Germany):** A stable and secure grid operation with 100% inverter penetration and completely without conventional must-run units is feasible also in public electricity grids. However, grid forming operation in public power grids needs further requirement specifications, such as evidence of grid forming behavior, operational limits and fault-ride-through behavior, characterization of inverter-based inertia, and common test procedures and quality criteria.
- **PV hybrids in the island power system of El Hierro (Field application, Spain):** The objective of this process is to increase the share of renewable energies in El Hierro by coupling a PV-battery hybrid system to the hydro-wind power plant. Some initial results of the analysis are provided in this report.

**PV plant power quality** – smart PV plant designs can reduce harmonic current emissions.

The admissible harmonic current emissions of a PV plant are often an important limiting factor within the grid code compliance assessment procedure requested before grid connection. To overcome this issue, traditionally one can either choose a "stronger" point of coupling with the public network or by adding harmonic filters of the appropriate orders to the PV system. A good alternative to both measures is a detailed analysis of the PV plant design concerning harmonic emission. The report provides an example from a field application in Germany.

- **Minimization of harmonic current emissions of a PV plant (Field application, Germany):** Harmonic current superposition within PV plants with multiple (identical) inverters may contribute to a minimization of the total harmonic current at the point of coupling, depending on PV plant design with e.g. (Inverter number, inverter design, cable layout, etc.), harmonic order and operating point(s) of the different inverter.

**New services by PV systems** - PV inverter can provide additional services in hybrid DC/AC power systems.

The need for new ancillary and grid services in electric power systems will further emerge with the progress of the energy transition in many countries. For example, the introduction and management of a high share of variable distributed renewable energy sources could be carried out flexibly and efficiently in the context of hybrid (DC, AC) networks. They can represent promising solutions capable of combining the advantages of AC distribution systems with the concept of DC electricity distribution. Nowadays hybrid grids can represent a well-suited paradigm to energy communities and renewables clusters. They can operate in the grid-connected mode and under isolated conditions, however guaranteeing resource management. The report provides laboratory experiences from Italy about PV inverters in hybrid (DC, AC) microgrids.

- **PV inverter in hybrid (DC, AC) microgrids (Laboratory test, Italy):** PV inverters can be suitably controlled to provide DC side services but topological/ technological improvements are necessary in terms of power stage reliability.

**Further development of regulatory frameworks and grid codes is required** for a wide application of ancillary services by PV systems and PV hybrids

To meet CO2 emission reduction targets and climate goals, PV deployment in the electric power system will increase rapidly in the upcoming years in many countries worldwide. However, keeping up the pace in developing appropriate regulatory frameworks and grid codes supporting PV integration in the electric power system is not an easy task. The regulatory frameworks and grid codes should not only cover current power system needs and demands but also anticipate the power system needs within the next (ten) years with increasing PV and other RES penetration levels. Therefore, regulatory frameworks and grid codes have to be continuously monitored and updated and should represent the state-of-the-art. Stakeholders and decision-makers should be well informed on the technical capabilities of PV systems and PV hybrids and the PV grid integration lessons learned from other countries or regions.

State-of-the-art PV systems can already provide a wide range of grid support functionalities, which are increasingly applied in national grid codes worldwide. These grid support functionalities are, for example, voltage and frequency ride-trough, active and reactive power control, voltage and frequency control, and dynamic grid support. Selected report recommendations on these inverter functions are:

- Development of a commonly established international standard for a cost-efficient and secure way to manage and update parameter settings of individual PV systems. This is increasingly required, to manage the wide variety and complexity of inverter settings and to remotely adapt PV systems for future power systems needs.
- Further and intensified collaboration between PV systems and distribution network operators is needed for the transformation to a 100% RES based power system. Digitalization and the introduction of the Smart Grid will help to gain the full potential from PV as an ancillary service provider. Relevant stakeholders, such as inverter manufacturers, PV project developers, monitoring companies and grid operators have to adapt its communication concepts and data models to these upcoming Smart Grids Standards.
- Continuous monitoring and compliance evaluation of the provision of the grid support functions and ancillary services by all generation types in normal and disturbed grid operation.
    - Development of solutions to obtain appropriate performance data of distributed PV systems in normal and disturbed grid operation and the development of necessary simulation models and analysis tools to predict the response of distributed generation fleets in case of a grid disturbance.
    - Adaptation of regulatory frameworks and compliance procedures, if necessary.

PV systems and PV hybrids can also provide several additional grid support functions and ancillary services beyond the current grid code and regulatory requirements. Field tests and field applications in this report show the proof of concept and technical capabilities of PV systems and PV hybrids. The regulatory frameworks in many countries should be further developed in order to encourage the application of additional grid support functions and ancillary services by PV systems and PV hybrids by the grid operator, wherever meaningful. Therefore, selected report recommendations are:

- The characterization and development of standards of advanced grid support functions, such as synthetic inertia or grid forming capabilities of inverter-based generators.
- Further development of common test procedures and quality criteria for advanced grid support functions that are best harmonized on an international level.
- Further development of existing ancillary service procurement procedures enabling the participation of PV systems or PV hybrids, such as for frequency control service.
- Further discussion and clarification on mandatory and optional grid support functionalities and ancillary services by the PV systems and other RES. This can require the development of new ancillary service products and new market-based procurement procedures for ancillary services by the grid operators.

# 1 INTRODUCTION

Solar PV is becoming a major source of electricity worldwide

In several countries, such as Honduras, Australia, Germany, Greece, Chile, Spain, Netherlands, Japan and Italy, PV provides already more than 8 % of the total electricity production (theoretical PV penetration 2020 in [5]). The highest share is determined in Honduras with a theoretical penetration level of 13 %, followed by Australia and Germany with 10.7 % and 9.7 % respectively [5]. Overall, PV generation covers about 3.7 % of the electricity demand worldwide [5]. The PV penetration in many countries is continuously growing. In the Stated Policies Scenario of the IEA world energy outlook 2019 (WEO 2019) [6], which incorporates today's policy intentions and targets, PV will become the largest source of installed generation capacity by 2040 (see Figure 1, left). In the Sustainable Development Scenario of the WEO 2019, which incorporates a systematic preference for increased efficiency and reduced emissions, PV will become the largest source of installed generation capacity before 2030. In the global electricity production, PV reaches a share of about 11 % in the Stated Policies Scenario and about 19 % in the sustainable development scenario of WEO 2019 [6] in the year 2040. The rapid growth of solar PV is driven by policy support and the improved competitiveness of solar PV [6].

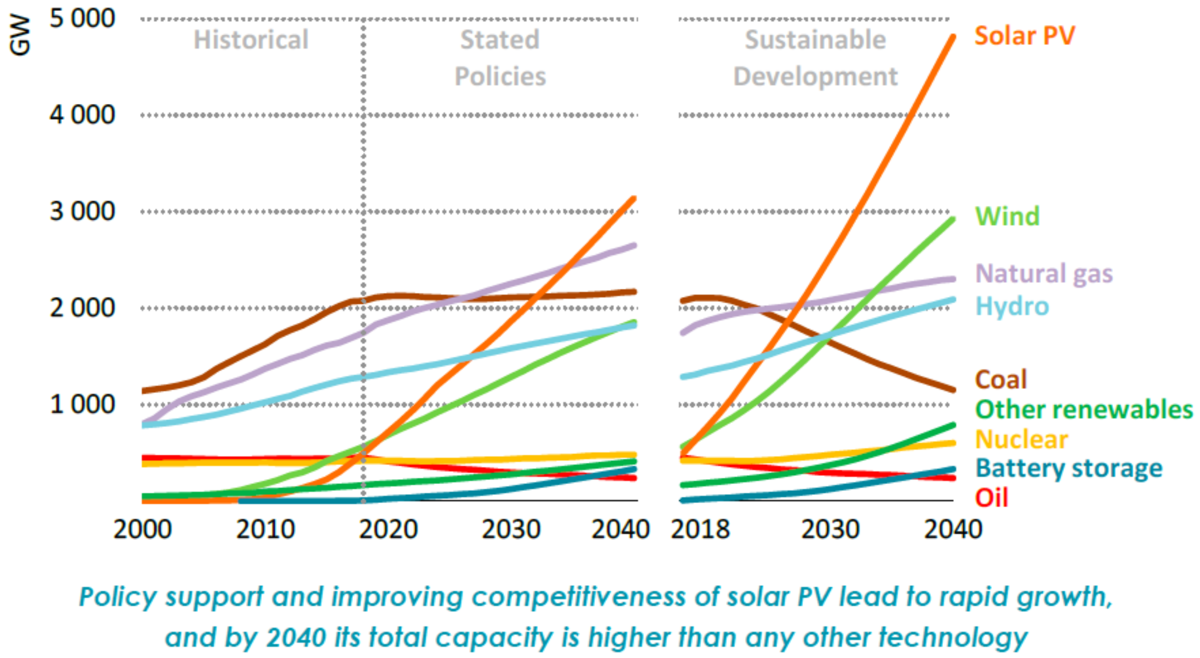


**Figure 1:** Global power generation capacity by source in the Stated Policies Scenario and the Sustainable Development Scenario of the IEA World Energy Outlook 2019 (source: **[6]**, all rights reserved)

Solar PV has to take over more and more system responsibility by providing ancillary services

Overall, PV is becoming a major energy source in the future electricity grid. Therefore, PV needs to take over more and more system responsibility by providing ancillary services. Ancillary service "means a service necessary for the operation of a transmission or distribution system" [1]. These services can be provided by grid users, such as conventional power plants, renewable energy sources (RES), storage units, or flexible loads, to support or ensure a secure and reliable power system operation. The specifications, types, needs and procurement procedures of these ancillary services can vary in different power systems and are changing with the progress of the energy transition in many countries. The following classification of ancillary services is provided for example in [7]:

- Loss compensation
- Frequency control
- Black start capability
- Voltage or reactive power control
- Oscillation damping
- Congestion management

Over the last years and decades, PV inverters have achieved a significant development driven by new and enhanced requirements for generators in various countries. PV systems have developed from passive grid users, which solely feed-in maximum active power and immediately disconnect in case of a grid disturbance, to active grid users, which can provide various grid support functions under normal and disturbed grid operation. Nowadays, widely applied PV inverter functions are, for example, autonomous grid support functions, such as Volt-Var or Frequency-Watt. However, on the way to renewable energy sources and inverter-dominated power systems, new challenges in power system operation become more and more relevant and the role of PV as an ancillary service provider will further enhance.

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The report highlights the status quo and the potential of PV and PV hybrids as an ancillary service provider

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The report aims to highlight the status and the potential of PV and PV hybrids as ancillary service providers. The report provides a collection of laboratory and field experiences from different IEA PVPS countries and for different ancillary services and PV inverter functions. The target groups of this publication are especially grid operators and decision-makers, which may not be aware of the status and the potential of PV and PV hybrids as ancillary service provider. The focus is set mainly on good practice examples. Nevertheless, improvement and further development potential and needs for the application of PV as an ancillary service provider are also addressed and discussed.

# 2 PV GRID INTEGRATION CHALLENGES

This Chapter and Figure 2 provide an overview of identified and expected grid integration challenges at different PV and other Variable Renewable Energy (VRE) penetration stages in electric power systems. The provided overview is based on a previous IEA PVPS Task 14 report [8] and the IEA report System Integration of Renewables [9]. Furthermore, the PV inverter functionalities in focus in each stage are also highlighted. The challenges are here distinguished between regional and system-wide challenges:

- **Regional integration challenges** are related to highly location-dependent services, such as voltage control, power quality, protection coordination, or congestion management. Every transmission and distribution grid operator is responsible for the surveillance and coordination of these services.
- **System-wide integration challenges** are related to non highly location-dependent services, such as balancing of demand and generation and frequency control. Transmission system operators are usually responsible for the surveillance and coordination of these system-wide services.

The spatial expansion of the system-wide challenges depends on the size of the power system. For example in Europe, system-wide challenges can cover power systems of different countries and millions of consumers and generators. In island systems or small remote power systems, system-wide challenges may only include a small area with very few consumers and generators.

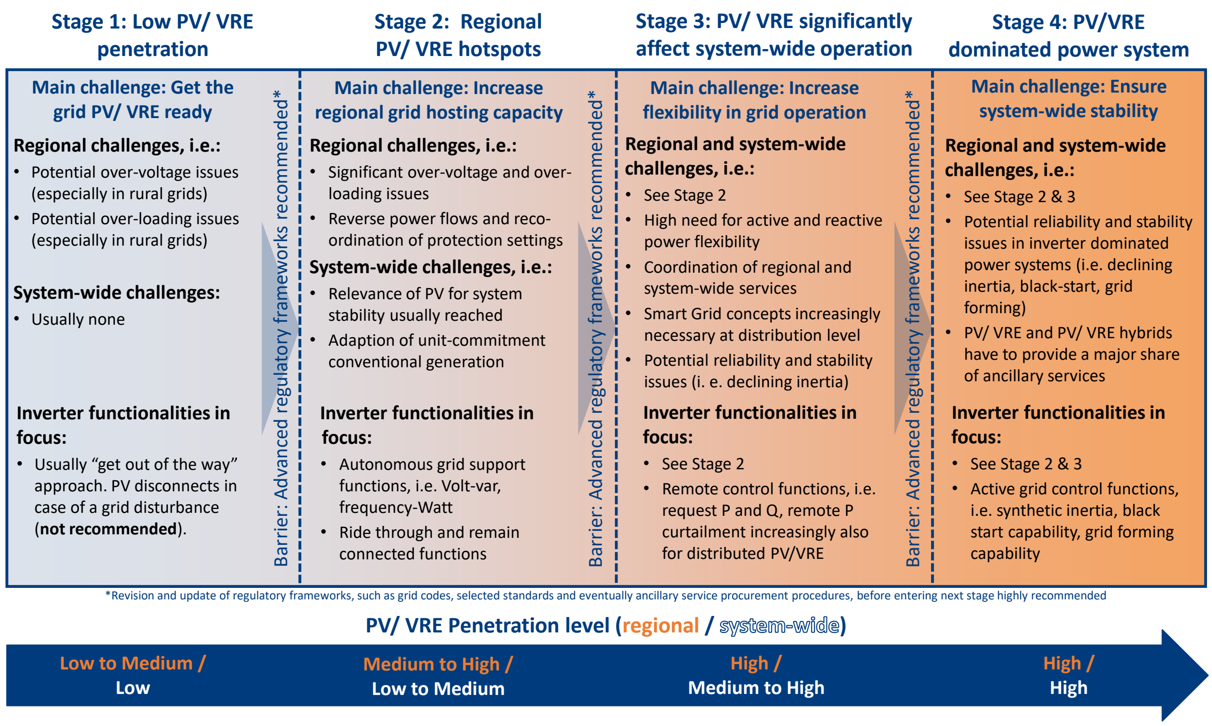



**Figure 2:** PV/ VRE penetration level and identified challenges for the electrical power systems

**Stage 1: Low PV/ VRE penetration**

Main challenge: Get the grid PV/VRE ready

In **Stage 1** regional consumption still exceeds regional generation. In rural grid areas or at weak grid connection points, PV may cause local over-voltage, over-loading, or power quality issues. Overall, PV has no noticeable impact on system-wide services, such as frequency control. In this phase PV usually plays a passive role; PV feed-in maximum active power and immediately disconnects in case of a grid disturbance. However, this "get out of the way approach" (do not disturb the conventional generators in case of a fault event) is not recommended. Because keeping up the pace in the regulatory framework development with a fast increase of PV penetration can be a challenge. A well-known example is here the 50.2 Hertz problem in Germany. In the German guideline for low voltage generators from 2005, PV systems were required to disconnect at 50.2 Hz. Due to the fast PV expansion, the installed PV capacity in Germany reached more than 25 Gigawatts at the end of 2011 and a shutdown of several Gigawatts of PV power at 50.2 Hertz could become a threat for the overall power system stability. Consequently, a costly retrofit of more than 300,000 existing PV systems was necessary as a precautionary measure (based on the description in [10]). Therefore, in this phase, the basis for a higher PV penetration level should be provided by the development of appropriate grid codes.

**Stage 2: Regional PV/ VRE hotspots**
Main challenge: Increase the regional PV/ VRE hosting capacity

In **Stage 2** the regional generation can relevantly exceed regional consumption, and significant over-voltage or over-loading, or power quality issues can appear in some grid areas, in case no appropriate measures are applied. A major focus in this stage is the increase of the PV hosting capacity, for example by grid reinforcement and grid expansion. Furthermore, autonomous PV inverter functions, such as volt-var control, power factor control, or volt-watt control, can support the voltage regulation and can further increase the PV hosting capacity (see IEA PVPS Task 14 report – Do it locally [3]). In power systems, where PV is mainly connected at the distribution level, bidirectional power flows from distribution to transmission level are increasingly observed. This can require the adaption and coordination of protection settings at the transmission and distribution level. In some cases, remote control functions of PV inverter (especially for utility-scale PV), such as a remote adjustment of the maximum active power generation can be used for congestion management. From the system-wide perspective, PV becomes relevant for the overall system-wide stability, and fault ride-through and remain connected functions are necessary. PV systems can support the frequency control by the Watt-frequency droop function. However, the major share of ancillary services is still provided by conventional generators.

**Stage 3: PV/ VRE variability and uncertainty significantly affect the system-wide operation**
Main challenge: Increase flexibility in grid operation

**Stage 3** is characterized by a significant level of uncertainty and variability due to a large share of PV and other VRE in the integrated power system. Active and reactive power flows in the power system can become more changeable and dynamic because of changing weather conditions and seasonal and daytime variations. Overall, high demand for active and reactive power flexibility characterizes this stage, and new sources for flexibility, such as storage, demand response, sector coupling, or FACTS are increasingly required. In most countries, a large share of flexibility by generators, storages, or loads are located at the distribution level and a challenge becomes advanced coordination of transmission and distribution system operation and market services. The implementation of Smart Grid concepts at the distribution level, including advanced communication, monitoring, state estimation, forecasting, and control, is a key enabler to harness the increasing amount of flexibility at the distribution level. Utility and commercial PV systems and increasingly residential PV systems can provide flexibility by remote control functions, such as the remote active power dispatch for balancing services and congestion management or a remote reactive power dispatch for voltage regulation also across different voltage levels.

In a power system with declining conventional generation, concerns about the overall system stability (i.e. declining inertia) and a general change in system behavior during critical situations (voltage and frequency response), need to be addressed and observed.

**Stage 4: PV/ VRE dominated power systems**
Main challenge: Ensure system-wide stability in an inverter dominated power system

In **stage 4** VRE (especially Wind and PV) can reach up to 100% of the demand on a system-wide scale during sustained periods. Besides the addressed flexibility challenges in stage 3, stability aspects in operation and planning of inverter-dominated power systems become urgent. Synchronous generators have intrinsically various properties, which helped to operate the electric power system over decades, such as inertia from rotating masses and grid forming capabilities. Inverter-based generators do not have these properties intrinsically and control-based functionalities are required to emulate or even enhance the properties of synchronous generators. Therefore, additional requirements and ancillary services are needed from inverter-based generators and storages, such as synthetic inertia, additional short-circuit current, and/ or grid forming capabilities. Furthermore, also black-start capabilities of PV/VRE hybrids will become more and more important. In this stage, PV/ VRE and PV/VRE hybrids have to provide a major share of ancillary services for the grid operation. The field applications from insular power systems can provide an outlook and important lessons learned also for inverter-dominated large interconnected power systems.

Start early with the preparation of the power system for higher PV/ VRE penetration stages and be aware of lessons learned from other countries.

The transition between the described stages is a continuous process. In Figure 2, the challenges are highlighted in the stage, where the highest transformation efforts in grid operation and planning are expected. Nevertheless, each change in power system operation and planning requires comprehensive preparation, including for example problem identification, impact assessment, solution evaluation, and eventually updating the regulatory frameworks, which needs to be prepared during previous stages. Also in subsequent stages, the described challenges usually remain, but state-of-the-art procedures exist in grid operation and planning to address these challenges. The main task is here the regular monitoring, review, and eventually the improvement of the applied procedures and solutions.

# 3 PV INVERTER FUNCTIONALITIES

## 3.1 Evolution of national and international Grid Codes

Following the growing penetration levels of distributed energy resources (DER), in particular variable static inverter-based RES (IBR) connected to the distribution grids, local, national, and international grid codes, utility regulations, and interconnection standards have been increasingly demanding for various additional, advanced functionalities to be provided by the generators. While at first, grid support functionalities were primarily demanded from large utility-scale generation connected to high- and medium-voltage (HV/MV) grids, many of the current grid codes specify similar requirements even for small (residential) generators, connected to LV distribution systems.

The developments in the grid-codes worldwide are the result of a fundamental paradigm shift regarding the approach for connecting DER, moving from a “fit and forget” practice and towards an active integration of DER into the power systems. Since then, there is wide consensus among basically all involved stakeholders, including distribution and transmission system operators as well as industry, that distributed resources has to support power system operation in order to ensure stable and reliable operation of a power system where a major share of the power is supplied from distributed resources.

This evolutionary process at the distribution level began in the late 2000s, when German grid codes for medium-voltage connected generation first introduced requirements for DER to support the grid during operation. Since then, numerous countries have introduced related requirements, continuously adding additional capabilities and specifying further details with respect to grid support features. Today’s revisions of the interconnection specifications define requirements for capabilities and advanced DER functions, including voltage and frequency ride-trough, active and reactive power control, voltage and frequency control, and dynamic grid support.

While there have been major advancements in global grid codes, there are still major gaps in the current specifications, in particular related to the implementation of smart, remotely controlled functions as well as functionalities which would be necessary in a future system with significantly lower inertia.

## 3.2 Common definition of functionalities and parameters

The evolutionary development of grid codes and regulations has created an increasingly complex landscape of specifications for capabilities, functionalities and associated details.

In addition, a common definition of advanced grid support functions and associated parameters is still lacking and creates further difficulties for comparing and relating the required functionalities in different jurisdictions and markets.

To overcome the lack of a common specification, a first definition of grid support functions has been introduced in [11] for the purpose of a comparison of requirements in the individual countries. The list covers the requirements and definitions in current standards, taking into consideration the initial definitions introduced by the IEC TR 61850-90-7 [12]. The initial list has been amended following the newly introduced requirements in the latest versions and is presented in Table 1.

**Table 1** List of grid support functions applied today and comparison with definitions in major international documents

| Requirement/ Function | Description | IEC TR 61850-90-7 (2013) | EU Network Code RfG *) (2016) | IEEE 1547 **) (2018) |
|---|---|---|---|---|
| **Capabilities** | | | | |
| Operational frequency range | Defined grid frequency range, where the generator can operate normally. | N/A | ABCD | X |
| Operational voltage range | Defined grid voltage range, where the generator can operate normally. | | BCD | X |

| Requirement/ Function | Description | IEC TR 61850-90-7 (2013) | EU Network Code RfG *) (2016) | IEEE 1547 **) (2018) |
|---|---|---|---|---|
| Q/cosφ range | Defined reactive power or cosφ to be provided by the generator | N/A | BCD | X |
| UVRT (LVRT) Under (Low) voltage ride through | Capability to remain connected during transient voltage dips (sags) | (TV31) | BCD | X |
| OVRT (HVRT) Over (High) voltage ride through | Capability to remain connected during transient voltage swells | N/A | N/A | X |
| ROCOF Immunity | Capability to remain connected and operate normally during transient frequency variations | | ABCD | X |
| **Autonomous Control modes based on local grid conditions** | | | | |
| **Active power related** | | | | |
| P(f) at over frequency | Reduction or limitation of the active power at over-frequency in the grid. | FW21 / FW22 | ABCD | X |
| P(f) at under frequency | Increase of the active power at under frequency | FW21 / FW22 | ABCD | X |
| P(U) | Reduction or limitation of the active power at over-voltage in the grid | VW51/52 | N/A | X |
| P ramp-rate limitation | Limitation of active power ramp-rate (up/down) | N/A | N/A | X |
| Synthetic inertia | Increase or reduction of the active power feed-in based on the network frequency gradient (df/dt). | N/A | CD | (X) |
| Dynamic limitation of active power | Dynamic limitation of active power feed-in based on local load conditions | N/A | N/A | N/A |
| **Reactive power related** | | | | |
| Const Q/ cosφ | Reactive power control mode: Constant power factor | N/A | N/A | X |
| Q/Cosφ(P) | Reactive power control mode: Cosφ as function of active power | WP41/42 | N/A | X |
| Q(U) | Reactive power control mode Q as function of grid voltage U | VV11 / 12 / 13 | N/A | X |
| Q ramp-rate limitation | Limitation of reactive power ramp-rate (up/down) | N/A | N/A | X |
| Fast reactive current injection (dynamic voltage support) | Fast reactive current injection during transient under or over-voltage conditions outside the normal operating voltage range. | TV31 | BCD | (X) |
| **Commanded modes (remote control)** | | | | |
| External disconnect | Disconnection of the generator from the grid through an external signal | INV1 | N/A | X |
| External control of P | Set point or limitation of the active power through an external signal | INV2/4 | ABCD | X |
| External control of Q/ Cosφ | Set point for reactive power through an external signal | INV3 | BCD | X |
| **Interface protection and connection** | | | | |
| Interface protection | Disconnection of the generator in case voltage or frequency are outside defined ranges | X | N/A | X |
| Automatic connection | Automatic connection and entering service, if grid conditions are within defined ranges. | N/A | ABCD | X |
| *) Requirements are specified based on the EU NC RfG generator type classification<br>**) Requirements based on IEEE 1547 definition of performance categories (base B/III) | | | | |

The list of capabilities, functions, and control modes is based on the definitions of current documents and can be applied to compare and benchmark requirements and definitions in different jurisdictions. It does not include any requirements related to Interoperability, information exchange, information models and protocols to be provided by the DER.

## 3.3 Basic capabilities of inverters used in IBR

State-of-the-art IBR provide a broad range of functions with associated operating modes for supporting the grid. They can be categorized into autonomously controlled and remotely commanded functions. Autonomous functions operate based on the locally measured variables and quantities (such as e.g. grid voltage or frequency) and modify the output of the IBR accordingly. Remotely controlled functions receive their setpoints through signals provided by an external control center or other entity through a communication link.

Due to the nature of inverters as static power electronic equipment, their electrical characteristics are defined by the response of their internal controls, advanced function parameter settings, and local measurements to adjust their active and reactive power output by autonomously responding to local grid conditions, external signals, or schedules.

The controllability of an IBR is typically limited by the basic capabilities of the inverter and the availability of the primary power source, e.g. Solar PV or battery storage. The fundamental capabilities to provide active and reactive power are commonly described by the inverter's P-Q diagram. Figure 3 shows the possible working areas of a device in a four-quadrant view and the limits in terms of maximum and minimum active and reactive power that can be delivered.

The inverter is typically limited in software to operate within an apparent power circle to avoid exceeding the current rating of the power electronics as well as to keep within the apparent power requirements of the grid code.

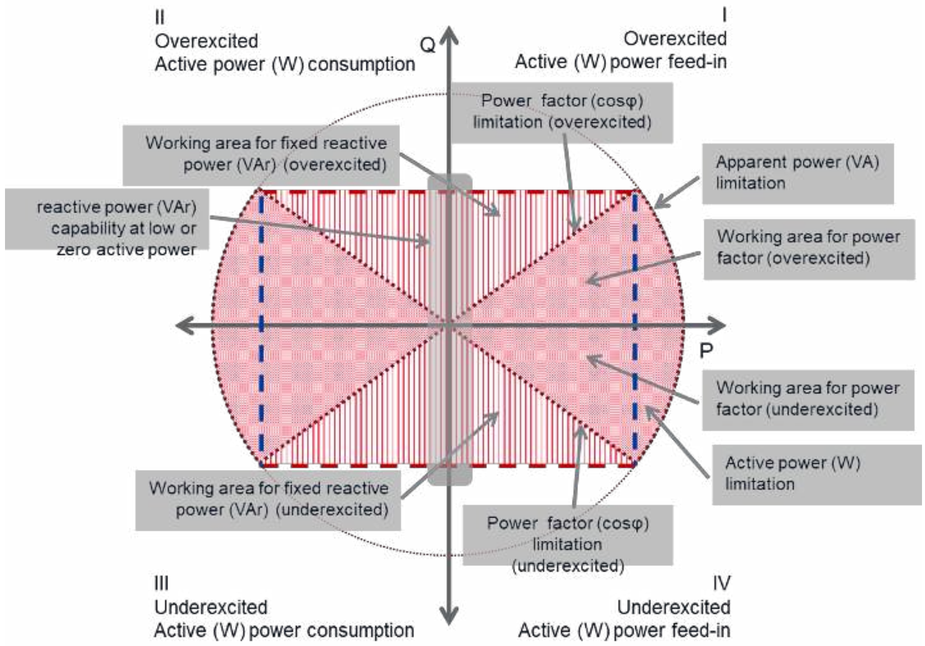



**Figure 3** Exemplary P-Q diagram of a typical 4-quadrant inverter used in IBR (generator reference frame) (figure adapted from **[13]**)

Inverters for use in generation-only installation can operate only in quadrants I and IV (in generator reference frame), while inverters for use with storage systems are designed to work in all four quadrants as they can consume active power from the grid for charging electrical storage. Theoretically, an inverter would be capable of operating within the full semicircle of these quadrants. However, according to the requirements of the local grid codes, the capabilities are constrained through control software to the pie-slice-shaped area region in power factor (PF) controlled mode and the rectangular area for fixed reactive power (Q) operation mode. Additional constraints typically apply for the operation in fixed-var mode at very low or even zero active power feed-in, indicated by the shaded gray area in Figure 3.

Within its working areas, the inverter is free to set its reactive power output according to defined control modes, while active power can be controlled subject to the availability of the primary power source.

Typical control functions and modes of state-of-the-art DER converters are

- immediate control functions for active and reactive power/power factor
- control modes for reactive power such as volt/var Q(U), watt/PF cosφ(P)
- control modes for active power, frequency/watt P(f), or volt/watt P(U)
- ramping controls to achieve a defined time response of the functions
- remote connect and disconnect

In conjunction with a local storage, additional charge and discharge control functions are available.

Besides complex active and reactive control capabilities, state-of-the-art converters used in IBRs also provide ride-through capabilities to support the local distribution grid as well as the overall power system during faults and frequency deviations. In power systems with high shares of IBRs, ride-through capabilities are crucial to avoid the simultaneous loss of large distributed generation capacities and a resulting undersupply, which could be caused by remote faults in the power system or frequency variations.

High and low-voltage ride-through (H/LVRT), as well as frequency ride-through capabilities, are achieved by designing the internal current controls and converter hardware to be capable of operating also during high or low voltage and frequency levels which are outside the normal operating windows.

The fundamental requirements, during which faults a DER is not allowed to disconnect, are given in the local grid codes (Figure 4). Besides the ride-through (=must not disconnect) requirements, grid codes usually also specify how the inverter shall respond in terms of current injection. Typically, two options are required, momentary cessation (= current goes to zero) and fast reactive current injection, where the inverter injects a reactive current proportional to the actual change of the grid voltage.

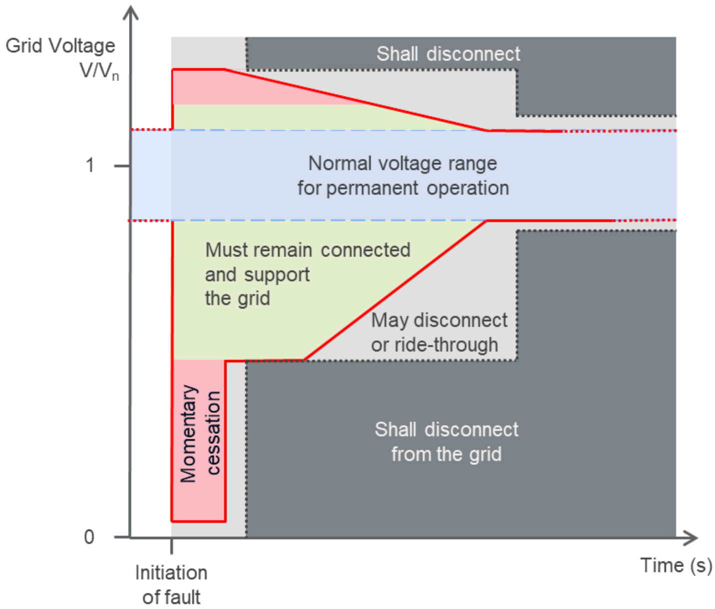



**Figure 4** Exemplary voltage ride-through capabilities for IBRs as demanded in today's grid codes (figure adapted from **[13]**)

Going beyond the advanced DER capabilities required by today's grid codes, latest state-of-the-art inverter technology can provide a range of further functions, such as e.g. advanced frequency response (synthetic inertia), compensation of unbalanced voltages and harmonics etc. These functionalities are already available today, however, there is still a high level of uncertainty about how to effectively apply them in practice. Therefore, they are not yet included in the grid codes.

## 3.4 Interrelation of inverter capabilities and functions

To effectively apply the grid support functions in practice, it is important to understand the interrelation of the individual functions and capabilities, particularly their prioritization. If this is not thoroughly defined in the grid code and/or individual parameters are not set properly on-site, situations may occur, where the correct operation of one grid support function is "overruled" by another function.

A typical conflict may be e.g. when FRT capabilities – namely not to disconnect during a transient voltage dip – are "eliminated" by an inappropriate setting of the interface protection. In this case, since the protection always has the highest priority, the generators would disconnect even though they are capable to provide ride-through.

To visualize the interrelations of the capabilities and functions, a pyramid model as shown in Figure 5 can be used. In this model, the various functions are assigned to individual levels of the pyramid, where each function builds on capabilities.

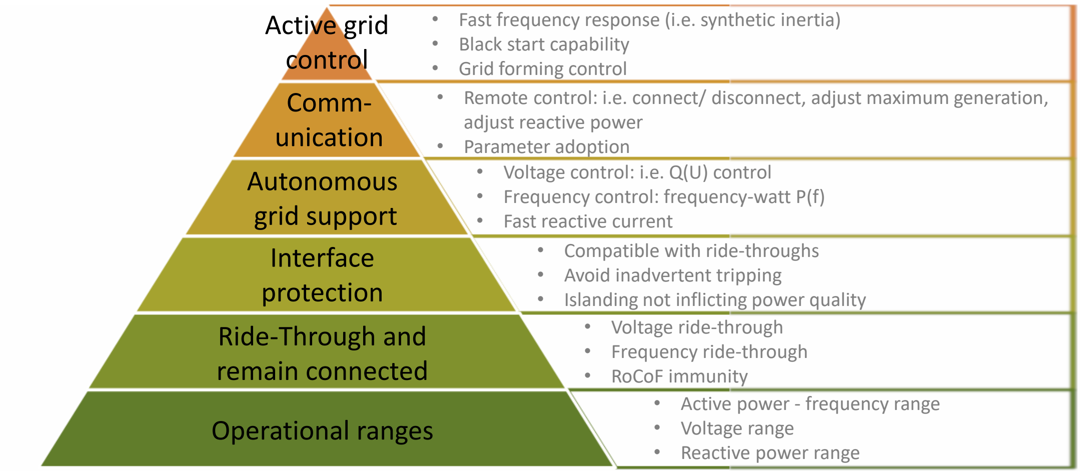



**Figure 5:** A hierarchical model for the definition of interrelations between various advanced inverter functions

The individual levels of the pyramid are defined as follows:

- Base level: At the base level, the operational ranges define the fundamental capabilities and ranges where the inverter can operate normally. Specifically, they include
    - Active and reactive power range of the inverter, including the dependency on grid conditions (voltage dependent P-Q diagram)
    - Grid voltage and frequency ranges where the inverter can operate normally
- Building on the operational ranges, the next level covers various ride-through capabilities, including
    - Voltage ride-through,
    - Frequency ride-through, and
    - RoCoF withstand capabilities.
- On the next level, the requirements for the interface protection are defined, which have to be compatible with the ride-troughs, avoid inadvertent disconnections and make sure that power quality is not negatively affected, e.g. by active unintentional-islanding prevention schemes.
- Going to higher levels, autonomous grid support functions will control the inverter to appropriately respond to changing grid conditions and support grid operation
- Communicated grid support functions will enable further capabilities to be utilized, such as remotely controlled active and reactive power, remote cease to energize, parameter adoption, etc.
- For selected system-relevant generators fully integrated into the power system operation, additional functions are required, including inertial response, black start capability and grid-forming controls.

With the technology on the inverter side already available, the main challenge remains: How to manage all these capabilities given the massive numbers of IBRs in the system. In particular, there is still no common solution on how to manage the wide variety of parameter settings, define settings appropriate for the local grid conditions and finding cost-efficient yet secure ways to manage and update settings of individual IBRs in order to be able to adapt them to future needs. While many vendors of inverter equipment already provide proprietary solutions to enable e.g. remotely updating settings, there is still no commonly established standard that can be widely applied.

## 3.5 Overview of current grid-support requirements for inverter-based generators

Today's grid codes and local interconnection specifications define a wide range of capabilities and grid-support functions to be provided by generators connected to the distribution systems.

An overview of current requirements, based on the common definition introduced in 3.2 is presented in Table 2, including references to the relevant documents.

**Table 2 Selected country requirements for inverter-based generators, connected to LV distribution grids**

| | NC RfG* | EN 50549-1 | DE | IT | AT | FR | ES | DK | UK | US |
|---|---|---|---|---|---|---|---|---|---|---|
| **Scope** | **Type A** | **LV** | **LV** | **LV** | **LV** | **LV** | **LV** | **LV** | **LV*** | **N/A*** |
| Power limit (MW) | ≤1 | ≤1 | ≤0.135 | ≤0.011 | ≤0.25 | ≤1 | ≤0.1 | ≤0.125 | ≤1 | N/A |
| **Capabilities** | | | | | | | | | | |
| frequency range | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| voltage range | N/A | Yes | Yes | Yes | Yes | N/A | N/A | Yes | Yes | Yes |
| Q/cosφ range | N/A | Yes | Yes | Yes | Yes | N/A | N/A | Yes | N/A | Yes |
| UVRT | N/A | Yes | Yes | Yes | Yes | N/A | N/A | N/A | N/Y | Yes |
| OVRT | N/A | Yes | Yes | Yes | No | N/A | N/A | N/A | N/A | Yes |
| ROCOF Immunity | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| **Active power related** | | | | | | | | | | |
| P(f) at over frequency | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| P(f) at under frequency | N/A | Yes | Yes | Yes | N/A | N/A | N/A | N/A | N/A | Yes |
| P(U) | N/A | Opt. | Opt. | Opt. | Yes | N/A | N/A | N/A | N/A | Yes |
| P ramp-rate | N/A | No | Yes | N/A | N/A | N/A | N/A | N/A | N/A | Yes |
| Synthetic inertia | N/A | No | N/A | N/A | N/A | N/A | N/A | N/A | N/A | Opt. |
| Dyn. P limitation | N/A | No | Yes | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Reactive power related** | | | | | | | | | | |
| Const Q/ cosφ | N/A | Yes | Yes | Yes | Yes | N/A | N/A | Yes | N/A | Yes |
| Q/Cosφ(P) | N/A | Yes | Yes | Yes* | Yes | N/A | N/A | Yes | N/A | Yes |
| Q(U) | N/A | Yes | Yes | Yes* | Yes | N/A | N/A | N/A | N/A | Yes |
| Q ramp-rate | N/A | Yes | Yes | N/A | Yes | N/A | N/A | N/A | N/A | Yes |
| Fast reactive current injection | N/A | No | N/A | N/A | Opt.* | N/A | N/A | N/A | N/A | Opt. |
| **Commanded modes (remote control)** | | | | | | | | | | |
| External disconnect / cease to energize | Yes | Yes | Yes | Yes | Yes | N/A | N/A | Yes | Yes | Yes |
| External control P | N/A | Yes | Yes | Yes | N/A | N/A | N/A | N/A | N/A | Yes |
| External control Q/ Cosφ | N/A | Opt. | Opt. | Opt. | N/A | N/A | N/A | N/A | N/A | Yes |
| **Interface protection and connection** | | | | | | | | | | |
| Interface protection | N/A | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Automatic connection | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |

| | NC RfG* | EN 50549-1 | DE | IT | AT | FR | ES | DK | UK | US |
|---|---|---|---|---|---|---|---|---|---|---|
| Remarks | * non exhaustive requirements subject to implementation in national codes | - | * Not required | * additional lock-in/-out function | * On request of DSO | | | | * Type A ≤16 A/>16 A | * For category B/III |
| Reference document | (EU) 2016/631 (NC RfG) | EN 50549-1:2019 | VDE AR N 4105: 2018-11 | CEI 0-21:2019 | TOR Erzeuger Type A:2019-07 | Arrêté du 23 avril 2008 Enedis-NOI-RES_13E V 7 2018 | Propuesta OM Códigos de Red Norma Tecnica Supervision V1.0 | Dansk Energi Guide for connection of power-generating plants to the low-voltage grid Type A and B V1.1 | ENA_EREC_G98_2018 ENA_EREC_G99_2018 | IEEE 1547 |
| Last update | 2016 | 2019 | 2018 | 2019 | 2019 | 2019 | 2019 | 2019 | 2018 / 2018 | 2018 |

The review of national grid codes and relevant documents shows that today advanced inverter functions are commonly required in most European countries as well as the U.S. Specifically, the following functions are now commonly applied in most countries:

- Frequency control P(f) at over-frequency (in selected countries also for under-frequency)
- Reactive power capabilities
- Steady-state voltage support through different reactive power modes Q(U), cos phi(P)
- Fault Ride-Through capabilities
- Dynamic voltage support
- On-demand response via remote control and communication for larger generators.

However, there are still major differences between the individual countries, specifically related to the levels of details of the definitions in the national grid code documents.

# 4 LABORATORY AND FIELD EXPERIENCES

This chapter provides a collection of laboratory and field experiences from different IEA PVPS countries and for different ancillary services and PV inverter functions. The focus is set on mainly good practice examples. Nevertheless, improvement and further development potential and needs for the application of PV as an ancillary service provider are also addressed and discussed. The following table provides an overview on the laboratory and field experiences in this Chapter.

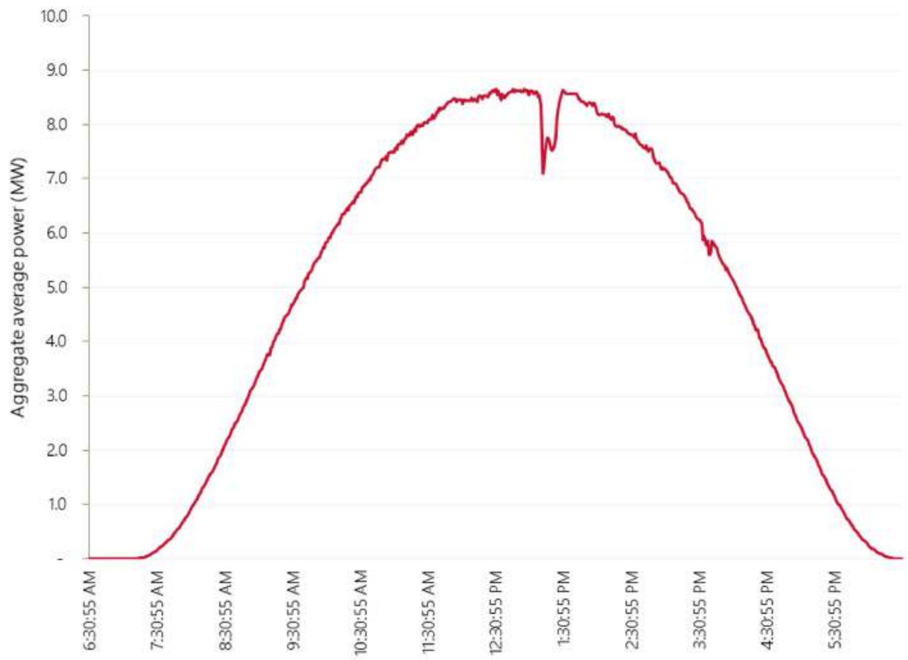
## 4.1 Distributed PV response to a major separation event and resulting frequency excursions in the Australian National Electricity Market, August 2018

Authors: N. Lal (ANU and AEMO), I. MacGill (UNSW)

| |
|---|
| **Considered PV systems:** PV system size (commercial / residential PV) and readiness level (commercial)<br>**Applied inverter functions:** Frequency-Watt P(f), Frequency fault ride through<br>**Main results:** Distributed PV systems played a useful role in assisting correction of a sustained over-frequency event in Queensland by reducing their output in accordance with AS/NZ4777.2-2015's specified frequency droop response.<br>**Further Information:** AEMO final Report [14] |

On 25 August 2018 a lightning strike on a transmission tower in Queensland, Australia triggered a series of faults which led to the complete separation of several States within the Australian National Electricity Market (NEM), and in under and over frequency events in different regions. These were managed to different degrees in the separate regions by contingency frequency responses, primary frequency control and under-frequency load-shedding. Importantly, the NEM has some 2.5 million distributed PV systems, and this event provided an opportunity to assess the response of PV inverters to major frequency disturbances [14].

Analysis of the response of distributed PV was made possible through an AEMO-UNSW-industry collaborative research project using data from approximately 5,000 monitoring devices distributed at PV households across the NEM's distribution network, kindly provided by Solar Analytics, a leading Australian PV system monitoring service [15].




Note the scale of this graph is showing output of the 1,700 monitored distributed rooftop sites in SA only, which is less than 10 MW in generation.

** Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

**Figure 6:** Aggregate average generation from distributed PV devices in South Australia (SA) monitored by Solar Analytics (~1700 sites < 100kW), 25 August 2018. SA was isolated during the event and experienced a period of over-frequency. Source: AEMO Final Report **[14]**

For over-frequency PV response, the current (2015) relevant standard AS/NZ4777.2-2015, required inverters to provide an over-frequency droop response once frequency exceeds a dead-band of 50.25 Hz (with a linear ramp to zero generation by 52 Hz). Inverters are allowed to gradually ramp back up once frequency moves below

50.15 Hz for at least 60 seconds. For under-frequency, the standard requires connection to be maintained until frequency drops below 47.00 Hz.

The report [14] found: *"a clear aggregate response of the correct shape and approximate magnitude, suggesting that this designed control response is correctly implemented in some proportion of the PV inverters."* It also found that the 2015 update of the previous 2005 standard (which did not have frequency equivalent response requirements) had a material impact on the aggregate response of inverters.

The analysis did also find non-compliance of around 15% of the analysed systems installed after October 2016 in Queensland (QLD), which has led to subsequent investigation and increased compliance monitoring.

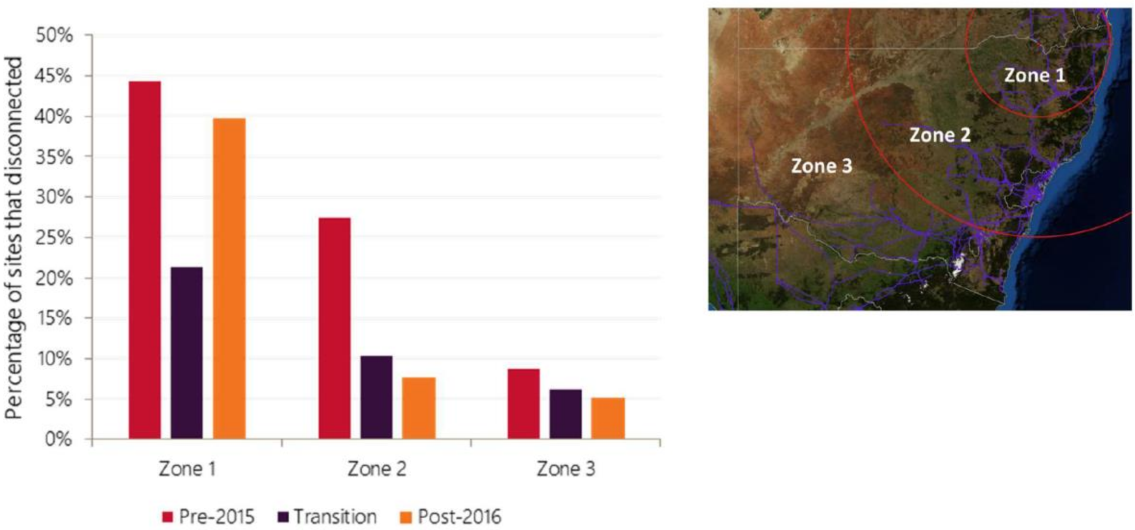

* Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

**Figure 7:** Comparison of the AS 4777.2-2015 specified response with behaviour of post-2016 distributed PV inverters in QLD, 25 August 2018. QLD's separation from the rest of the NEM saw an extended period of over frequency triggering distributed PV generation reductions that, in aggregate, largely followed the AS4777 specified frequency response. Source: AEMO Final Report **[14]**

The key recommendations of the report [14] for Distributed PV and interaction with standards/compliance are included below.

> **Report Recommendation 5**
>
> <u>Distributed PV inverter performance standards and analysis</u>
>
> Distributed PV – AEMO to work with industry and Standards Australia to:
>
> a) immediately assess technical requirements of inverters (AS 4777) and complete by Q2 2019
>
> b) work with stakeholders to implement improved performance standards for inverters by end of 2019
>
> c) establish solutions for obtaining data on the performance of distributed rooftop PV systems, and to develop the necessary simulation models and analysis tools to predict their response to system disturbances progressively up to the end of 2020.

These recommendations have been largely adopted. The Australian inverter standard AS 4777.2 has recently been updated (2021, see [16]) with revised sustained operation limits for frequency variations (Clause 4.5.3) and passive anti-islanding frequency limits (Clause 4.4).




*Disconnection is inferred from generation at a site suddenly reducing to zero. Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

**Figure 8:** Geographic distribution of monitored PV system sites disconnecting in NSW during 25 August 2018 event. The loss of interconnection with QLD saw NSW experience a period of low frequency yet some inverter disconnections. The spatial analysis highlighted that these disconnections were greater closer to the location of the original transmission fault, which also resulted in voltage disturbances that may have contributed to this otherwise unexpected response. Source: AEMO Final Report **[14]**

Going forward, there is a clearly identified need for both large-scale and aggregated-distributed PV to provide additional system support and ancillary services where possible, with likely increasing value for systems to maintain 'headroom' to provide operating reserve, more accurate forecasting, frequency support, and potentially grid-forming capability [17].

## 4.2 Frequency control services by Wind and PV power plants

Authors: S. Siegl (Fraunhofer IEE), J. Schütt (Fraunhofer IEE)

**Objective:** Provision of frequency regulation services by PV and wind power plants
**Field area /laboratory test:** various PV power plants in Germany
**Considered PV systems:** utility scale PV systems
**Applied inverter functions:** PV active power dispatch
**Main results:** The project provided indications that the provision of secondary and tertiary control by means of pools of wind and PV power plants is generally possible and practicable but depends in detail on the formulation of the accuracy requirements for balancing services by the transmission system operators.

Two challenges regarding the security of electricity supply come with increasing penetration of renewable energy sources (RES) and decreasing usage of fossil and nuclear fuels: the capacity for regulating power from conventional power plants decreases while the need for such ancillary services increases through the volatility of RES. This ability specifically of photovoltaic systems has been examined in this project.

The determination of a PV park's maximal power output for any given point in time is the basis of their provision of control power. The concept of possible feed-in is already in use for the identification of plant disturbances and production forecasts, but its temporal resolution is not sufficient yet for the requirements of balancing power. Improving it and answering the question of how the determination of possible feed-in can be improved by interlinking PV and wind parks was one of the working points of this project. Furthermore, the possibility of using probabilistic forecasts to generate bidding strategies for PV parks also considering the linkage with wind parks was considered.

There are two approaches to determine the possible feed-in of photovoltaic parks: One based on irradiation and temperature measurements of a reference cell (meteorological approach) and another using electric power measurements of power inverters (electric approach). This project examined the accuracy of both procedures as well as temporal and spatial balancing effects. The problem persisted that the quality of the determination could only be assessed in the non-curtailed cases. A statistical procedure tackling this issue was proposed.

The TSOs' prequalification conditions for the possible feed-in evaluation for the pilot phase (and after) of the parks are: $95.45\,\%$ $(99.73\,\%)$ within an absolute error of less than $10\,\%$, $68.27\,\%$ $(68.27\,\%)$ within $5\,\%$ $(3.3\,\%)$ and an absolute bias of less than $1\,\%$. The underlying data are 10.000 one-minute-mean values with each $> 10\,\%$ of a park's nominal power.

The prequalification conditions for photovoltaic balancing power provision of the TSOs demand a bias $< \pm 1\,\%$ as well as $95.45\,\%$ $(68.27\,\%)$ of the predicted possible feed-in values lying within $\pm 10\,\%$ $(\pm 5\,\%)$ of their true values. Until today, only **meteorological approaches** have been tried for determining possible feed-in of PV parks. For that reason the current study examined the electric approach in more detail. Specifically, a PV park in Delitzsch, Germany, with a peak performance of 32 MWp and 37 power inverters has been used. The underlying data consisted of a complete and errorless time series of 5-minute mean power values of all the inverters spanning October 2012 to March 2015. The meteorological method mentioned above uses one or several reference cells in the park to determine the temperature and irradiation. The electric approach makes use of electric power measurements and spatially interpolates the remaining values.

**Table 3:** Performance of this study's meteorological approach for possible feed-in determination (Ppq = prequalified power).

| | Requirements | Static parameter determination | Dynamic parameter determination |
|---|---|---|---|
| Bias | <+/-1% $P_{pq}$ | 2,67% $P_{pq}$ | 0,60% $P_{pq}$ |
| Percentage of errors within ±10 % $P_{pq}$ | >99,73% (>95,45%) | 86,57% $P_{pq}$ | 93,12% $P_{pq}$ |
| Percentage of errors within ±3,3 % $P_{pq}$ | >68,27% | 68,86% $P_{pq}$ | 78,61% $P_{pq}$ |

The model's parameters can be determined on a daily basis (dynamically) or only once for each day of the first year (statically), which is computationally preferable. As can be seen, neither way of parameter determination is compatible with the TSOs' prequalification conditions. The most likely reason for this is the spatial stretch of a photovoltaic park in opposition to the punctual nature of the meteorological measurements performed in this project.

As for the **electric approach**, it could be shown that three reference inverters are not enough to fulfill the accuracy requirements on account of their lack of spatial coverage. On the other hand, a high number of reference inverters has the power available for control purposes drastically reduced, which also leads to a higher error in relative numbers. Also, occurring errors in the remaining inverters (those not selected for measurements) are not represented by the majority of inverters. It can be seen that for a suitable number of reference inverters, all the electric reference methods (unity, static and dynamic efficiency ratios) fulfill the TSOs' requirements.

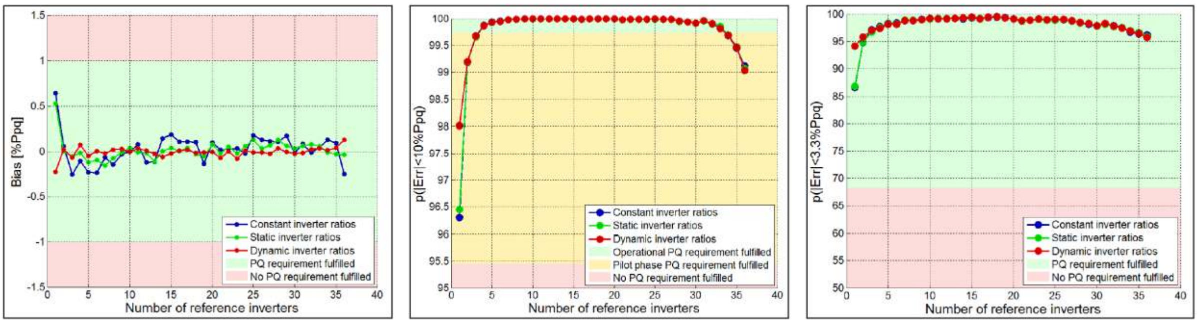



**Figure 9:** Performance of this study's electric approach for possible feed-in determination.

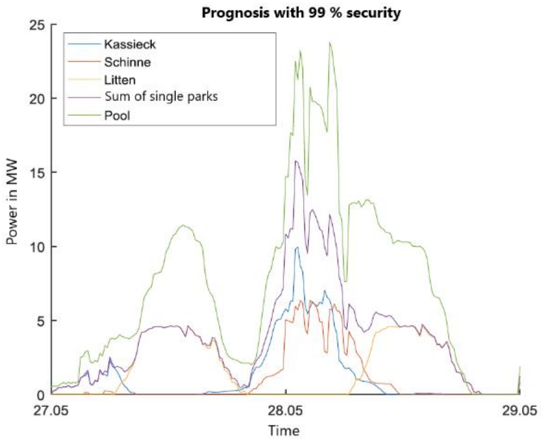
In another working point, various PV parks were evaluated with respect to their possible feed-in determination accuracy. For this purpose, the calculated values were compared to the actual feed-in in the non-curtailed case. Furthermore, special attention was attributed to balancing effects of pooling and of the averaging durations. The absence of a systematic error was proven and the standard deviation was shown to decrease with increasing nominal power, which is assumed to be the result of balancing effects. Shorter averaging durations were shown to lead to higher standard deviations. As can be seen in the table below, the accuracy of these parks' possible feed-in determination is only partly sufficient:

| Park | $P_{max}$ | Bias | < ± 10 % | < ± 5 % | < ± 3,3 % |
|---|---|---|---|---|---|
| Weira | 3,7 MW | -0,49 % | 97,55 % | 94,04 % | 87,44 % |
| Kleinlangenheim | 3,5 MW | -0,26 % | 93,55 % | 84,44 % | 75,94 % |
| Hörselberg-Hainich | 4,3 MW | -0,68 % | 98,45 % | 94,62 % | 91,50 % |
| Vahldorf | 4,7 MW | -2,16 % | 96,50 % | 84,95 % | 65,92 % |
| St. Gangloff | 1,7 MW | 0,48 % | 99,65 % | 97,54 % | 94,58 % |
| Weferlingen | 4,1 MW | -1,58 % | 97,06 % | 92,83 % | 79,37 % |
| Liebersee | 3,1 MW | -0,36 % | 99,23 % | 97,59 % | 96,00 % |

**Figure 10:** Performance of this study's possible feed-in determination for various PV parks.

This study also proposes a statistical procedure for identifying systematic errors in possible feed-in determination on the basis of curtailments at various heights. The key idea is that if the feed-in shortly before a curtailment and after are measured, they should be approximately the same. If, in case of sufficient data, this is not the case, it hints at the existence of a systematic error. This method showed that possible feed-in tended to be slightly underestimated for most of the examined parks.

In another working point, this study developed risk-based bidding strategies for PV parks based on probabilistic forecasts obtained from historical data. Figure 11 (left) shows a prognosis that can be made at 99 % security using distribution regression. It can be seen that the procurable balancing power of the pool is greater than the sum of the single capacities. From Figure 11 (right), it is evident that an increasing offer duration leads to significant loss of the amount of available power. The difference between the 1 hour product and the 4 hour product is especially high as the peak capacities are not available for 4 h products.



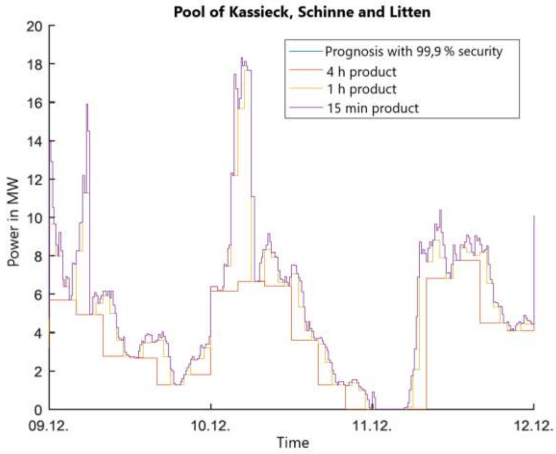




**Figure 11:** Forecast of available power with 99% and 99.9% security of a mix of PV and wind parks (wind parks: Kassieck, Schienne, PV park: Litten)

The table below shows how pooling of PV, wind and cogeneration plants (CHP) can increase the maximum available power capacities at given security levels. It is obvious that the relative reliability of such plants complements RES plants favourably in their control power contribution.

**Table 4:** Available power for different poolings of PV, wind and cogeneration plants and different security level

| Level of security | Wind + PV pool | CHP pool | Sum wind + PV + CHP | Wind + PV + CHP pool | Increase in maximum possible power |
|---|---|---|---|---|---|
| 99 % | 7,23 MW | 5,00 MW | 12,23 MW | 16,19 MW | 32 % |
| 99,9 % | 2,35 MW | 5,00 MW | 7,35 MW | 10,46 MW | 142 % |
| 99,99 % | 1,03 MW | 0,00 MW | 1,03 MW | 7,33 MW | 611 % |

A field test featuring a cluster of 12 PV parks was conducted on an exemplary day (May 18th 2017). For this purpose, the parks were each classified in one of three categories according to their marginal costs of electricity production. In the sense of an inverse merit order, the ones with the highest marginal costs were down regulated first, and the ones with the lowest costs last, which lead to the results shown in the three figures below, each for one cost category. It is clearly visible that lower marginal cost PV parks were only down regulated in the case where the higher cost PV parks had reached their downregulation limit. The field tests have shown that the considered parks have a prominent behavior. The parks could be quickly curtailed, but it needs some time to reach the full power after the curtailment. The behavior is shown in Figure 12.

**Conclusion** and lessons learned:

- In the project, a method was developed that determines the possible feed-in of a PV park based on the measured power of reference inverters. It was shown that this method is more accurate than a method based only on the measurements of a reference cell at one location in the park.
- In the project, probabilistic forecasts for individual parks were created and procedures for combining them into pool forecasts were developed. This showed the advantages of pooling compared to a simple summation of the individual park reserve power offers. In addition, it is shown that the possible reserve power offer dependends strongly on the factors security level and product lengths.
- In the field test, it was shown that under the given conditions, the dynamics of wind and PV power plants are sufficient to fulfill the condition for the provision of secondary frequency reserve.

- Detailed information on the lessons learned and further findings of the project are provided in the German project report [18].

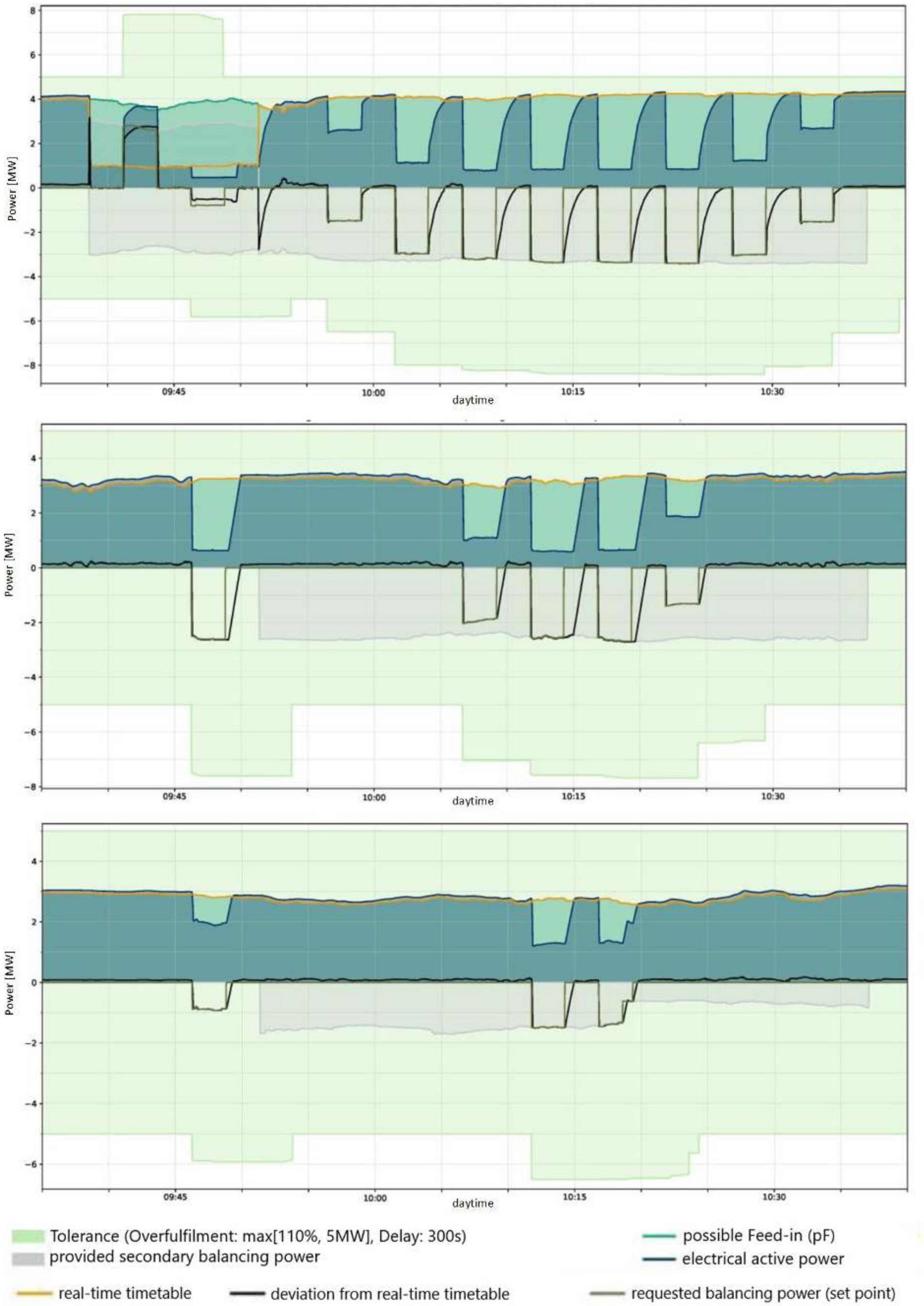



**Figure 12:** Results of PV cluster field test at 18th may 2017. (source: **[18]**)

## 4.3 Dynamic PV Power Curtailment

Authors: C. Bucher, Berner Fachhochschule

**Objective:** Avoiding grid connection overloading by dynamic reduction of PV power production
**Field area /laboratory test:** Demonstration project in a scholar building in Zurich, Switzerland
**Considered PV systems:** Commercial PV system (148.4 kW DC, 160 kVA AC), Control System Solar-Log 2000 PM+. For a trial period, the grid connection capacity was hypothetically limited to 32 kVA.
**Applied inverter functions:** Dynamic limitation of active power
**Main results:** The dynamic PV power curtailment works and is an economic measure to increase the PV hosting capacity of a grid. However, the precision of the controller is limited in the tested device. Therefore, an application of an additional safety margin is recommended to secure compliance with a defined feed-in limitation.

The peak power output of a photovoltaic (PV) system can be greatly reduced without the energy yield being noticeably lower. Peak power curtailment is therefore an economic and powerful method to increase the PV hosting capacity of a grid. Power curtailment is state of the art in todays PV inverters. Most inverter manufacturers offer different ways to curtail PV power, both remote controlled or based on local measurements. However, if less than 70% of the peak power is to be fed into the grid, the energy yield losses increase rapidly. A simple and inexpensive method of reducing these yield losses is dynamic active power reduction. It reduces the plant output, but only if the electricity cannot be consumed directly on site.

Active Power Curtailment (APC) ensures that the PV system can always run without limitations when the electricity is either fed into the grid or consumed locally. If this is not the case, it reduces the active power of the PV system. This system has various advantages for the customer: First, it is usually cheaper (also taking into account the loss of energy yield) than an otherwise necessary grid expansion or battery storage. Second, in the case of a self-consumption system, it not only reduces the energy drawn from the grid, but also the peak power delivered to the grid. The following components are necessary for the realisation of APC:

- An inverter which can reduce its maximum power dynamically
- A device for calculating the momentary permissible inverter power (this can be integrated in the inverter)
- A device for measuring the power delivered to the grid.

In this project, the following setup was chosen:

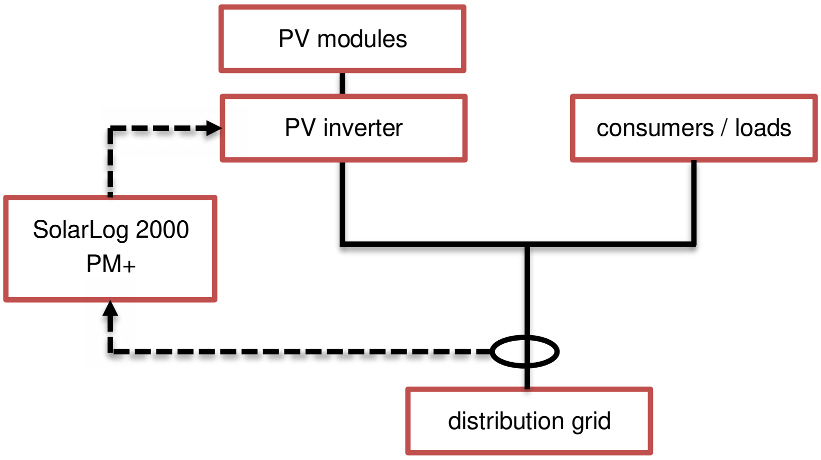



**Figure 13:** Schematic of the dynamic active power limitation at the network connection point.

In order to test the system, the control system (SolarLog 2000 PM+) has been set to a feed-in limit of 32 kVA. Figure 14 shows the production, the consumption and the feed-in power to the grid. It can be observed that the feed-in power is limited to 32 kVA. However, the control system doesn't manage to control this limit accurately and slightly exceeds the specified power limit. In the final implementation, a control error of roughly 10% was assumed. The grid connection limit was therefor set 10% lower than theoretically required. A reference and further information on lessons learned to this project are provided in [19].

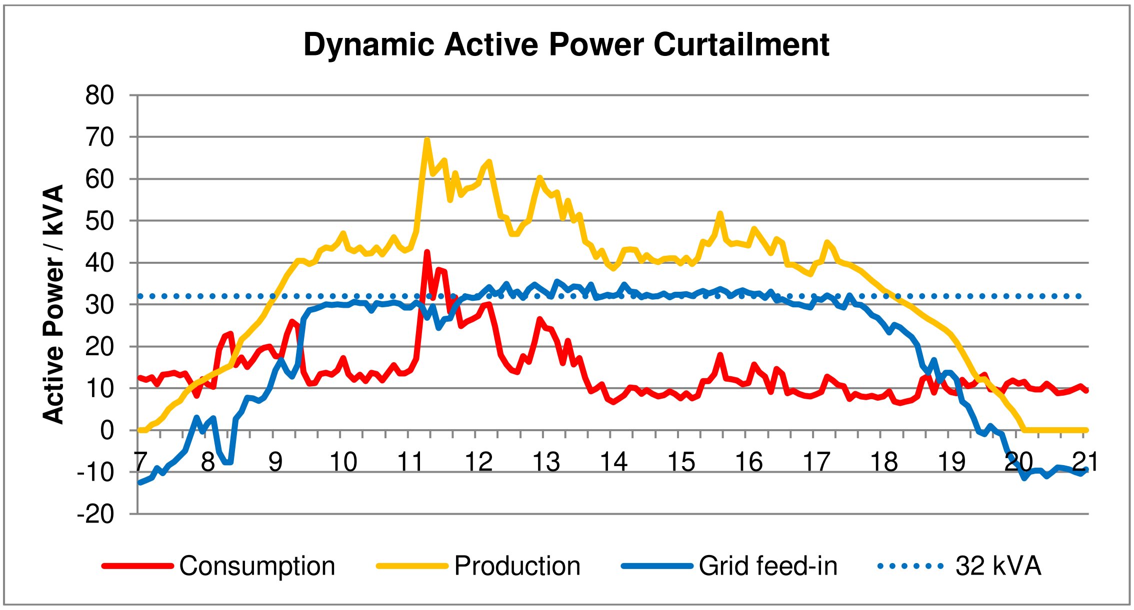



**Figure 14:** Control system measurements from August 24, 2016. Production (yellow) follows consumption (red) and grid feed-in (blue) only slightly exceeds the specified feed-in limit of 32 kW (dotted blue) **[19]**.

In [20] it is estimated how much curtailment losses can be recovered when curtailment is being done dynamically instead of fixed. The simulation model assumes a constant ratio between maximum tolerated PV peak power to maximum tolerated load peak power, which is a realistic assumption for distribution power grids. Furthermore it assumes a PV power curtailment of 50%. Looking at a single household, only about 15% - 20% of the curtailed energy can be recovered due to self-consumption. However, if 100 or more households are taken into account, 50% dynamic PV curtailment doesn't cause any energy yield losses at all.

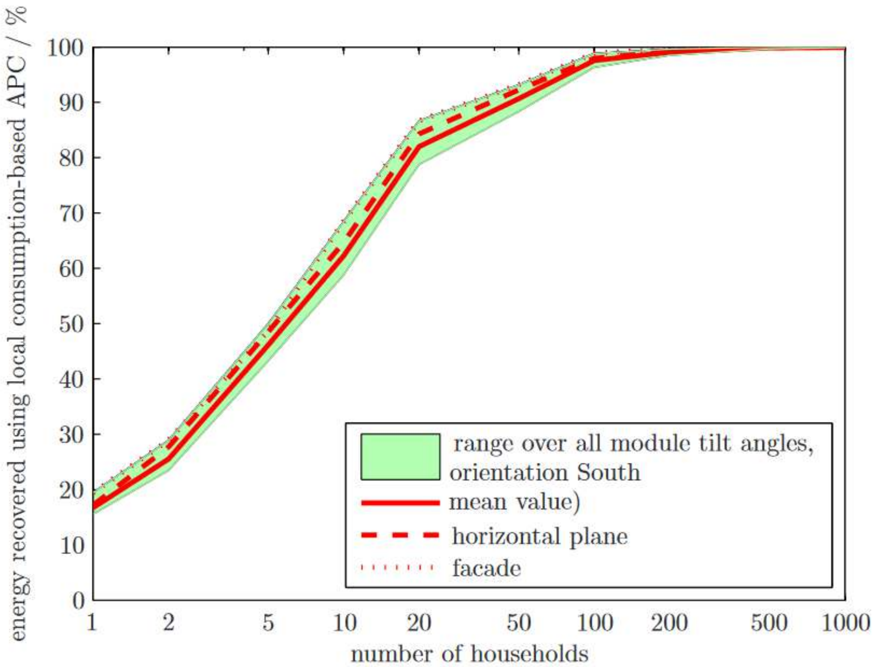



**Figure 15:** Percent of theoretically curtailed energy which can be recovered using dynamic active power curtailment according to the assumptions of **[20]**

## 4.4 Remote curtailment of residential PV systems via Smart Meter Gateway

Authors: G. Heilscher, S. Chen, C. Kondzialka, F. Ebe, H. Lorenz, J. Morris, B. Idlbi, P. Muratidis, Technische Hochschule Ulm – University of applied Sciences (THU), H. Ruf, D. Langer, Stadtwerke Ulm/Neu-Ulm Netze GmbH, Ulm Germany.

**Objective:** Integration of residential PV systems into Smart Grids by utilizing Smart Meter Gateways for PV curtailment.

**Field area /laboratory test:** Laboratory and field test at the Smart Grid Laboratory (THU) and the Smart Grid test site Hittistetten at Ulm, Germany.

**Considered PV systems:** Hittistetten is a small village in the countryside with about 130 households and several farmers. To date, 64 roof-mounted PV systems with a total capacity of 1250 kWp installed.

**Applied inverter functions:** Communication via SunSpec protocol to read inverter technical data, measurement values and control active power (curtailment)

**Main results:** With Digitalization and the introduction of Smart Grids an effective and economic remote curtailment will become available also for residential PV systems. The C/sells field test demonstrated the use of the Smart Meter Infrastructure (Smart Meter Gateway, SMGW-Admin, CLS-Gateway and CLS-Management) for a secured, bidirectional communication between PV inverters and a distribution control center. CLS-Gateway uses the telecommunication route established by SMGW to transmit measurements and curtailment commands based on IEC 61850 compliant data model. In addition to the curtailment, the Smart Meter Infrastructure enabled also energy market access. With the utilization of the IEC 61850 data model an automatic integration of massive residential PV systems into the distribution control center became possible and reduces the integration effort for RES.

With the transformation of the energy system towards a 100%, RES based power system the installed PV power will exceed the load by far due to the low amount of full load hours of PV systems. For the integration of these high amounts of installed PV power, a function for curtailment becomes mandatory. With the decentralized character of PV systems, an effective and economic remote access is needed also for residential PV systems.

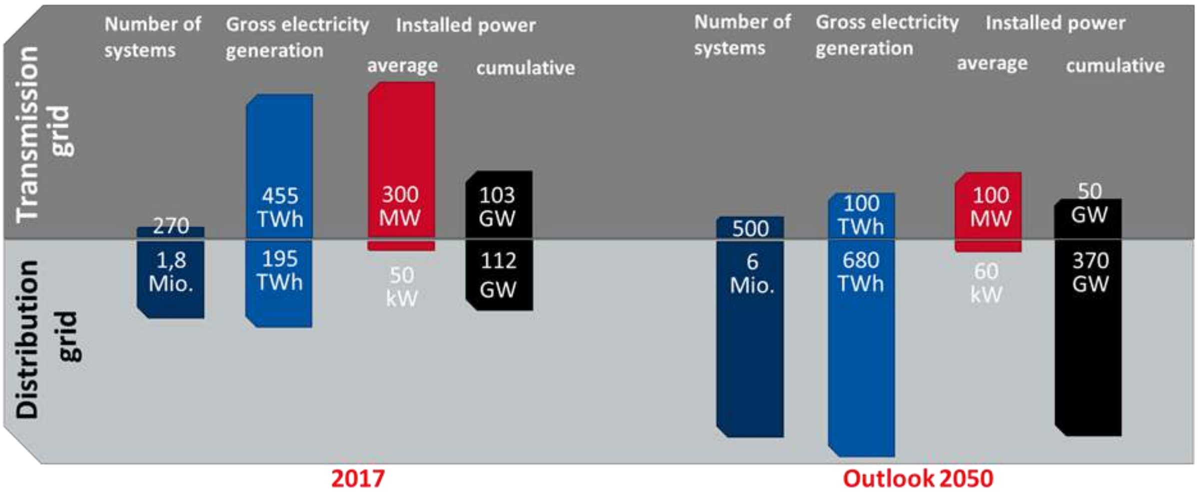



**Figure 16:** Comparison of the key indicators of the current German energy system and outlook 2050. These figures explain the challenge of the energy system transformation towards a decentralized energy system based on renewable energy sources. The distribution grid has to turn into a Smart Grid to be able to host the renewable energy systems and the additional new load from future sector coupling **[21]**, **[22]**, **[23]**.

The C/sells project in Germany demonstrated the cellular concept of a decentralized energy system and the integration of PV systems into Smart Grids and Smart Markets [24].

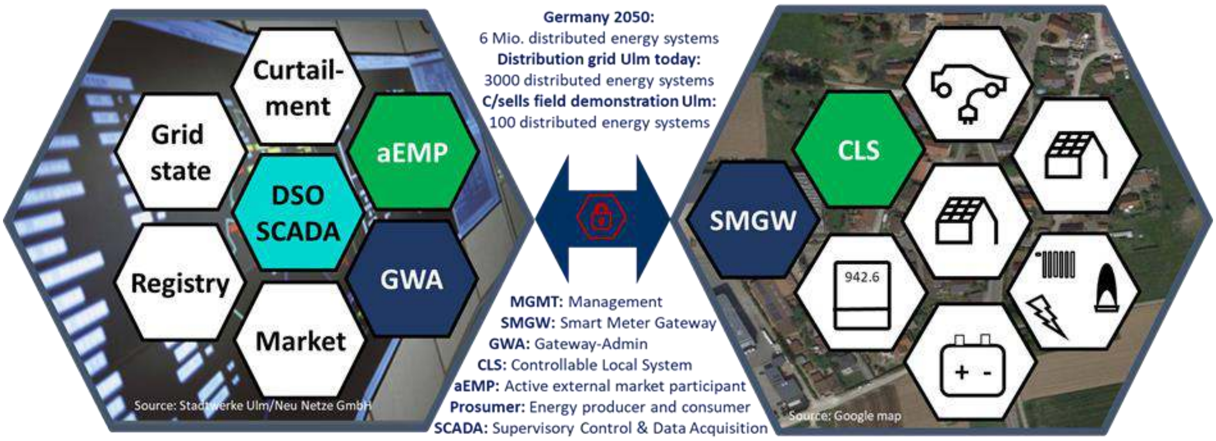



**Figure 17:** Integration of PV systems into Smart Grids with the use of Smart Meter Gateways (SMGW) [19]. The Controllable Local Systems (CLS) such as PV, E-mobility charging, battery systems or Power-to-Heat are connected with the CLS-Gateway [20], which maps the RES parameters on the field-bus level to data attributes compliant to IEC 61850 standard data model **[25] [26] [27]** and connects to the corresponding backend system through the secure communication channel established by SMGW. In addition to the PV curtailment also market access, state estimation of the low voltage network or automatic registration of RES become possible with the Smart Grid integration of PV systems.

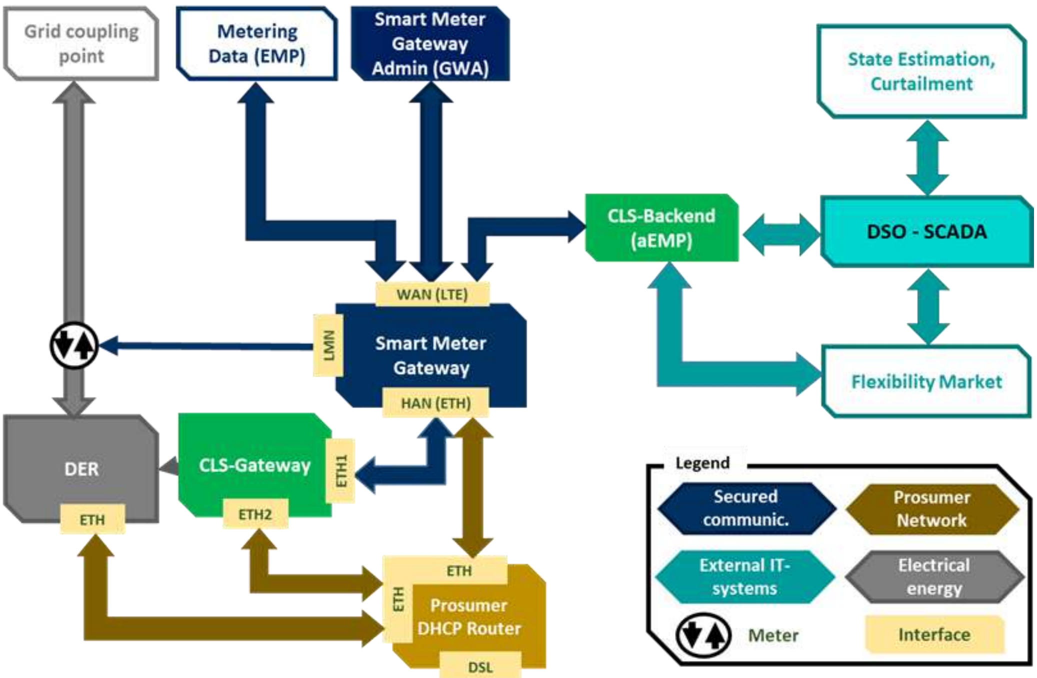



**Figure 18:** Smart Meter Infrastructure (SMI) in Germany is based on technical rules and common criteria that have been defined by the national cybersecurity regulator (BSI). The central device is the Smart Meter Gateway (SMGW), which acts as a secure router for the energy information network. The SMGW offers three interfaces. The WAN interface connects the SMGW over a closed LTE network with the Gateway Administrator (GWA) and the passive and active External Market Participants (pEMT=meter reading, aEMT=control, SCADA, curtailment, market and other active services). The LMN-interface connects the meters. The Home Area Network (HAN) connects the CLS-Gateway and the local Prosumer data visualisation. The CLS-Gateway connects controllable local systems like PV-inverters **[28]**.

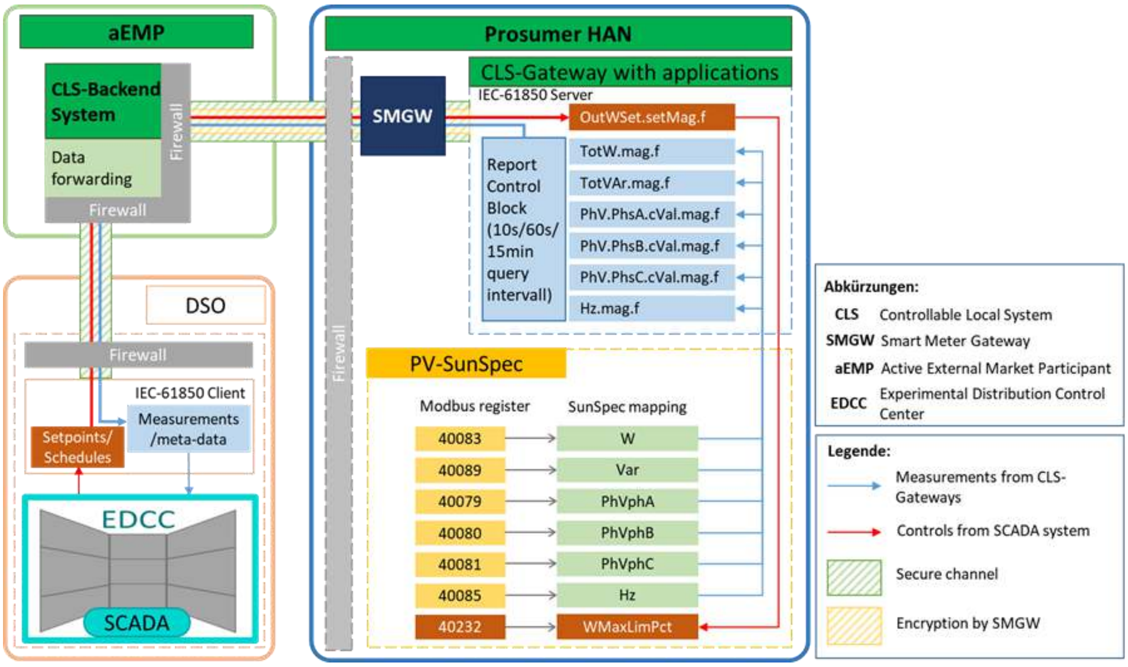



**Figure 19:** Communication with PV inverter via SunSpec protocol and mapping of the inverter values to the standardized IEC 61850 data model. Data Transmission to the experimental distribution control center (EDCC) / DSO-SCADA via the secure transparent channel of the SMGW. The grid operator can read values from the inverter and send commands like curtailment to an individual defined power reduction to the invert **[29]**.

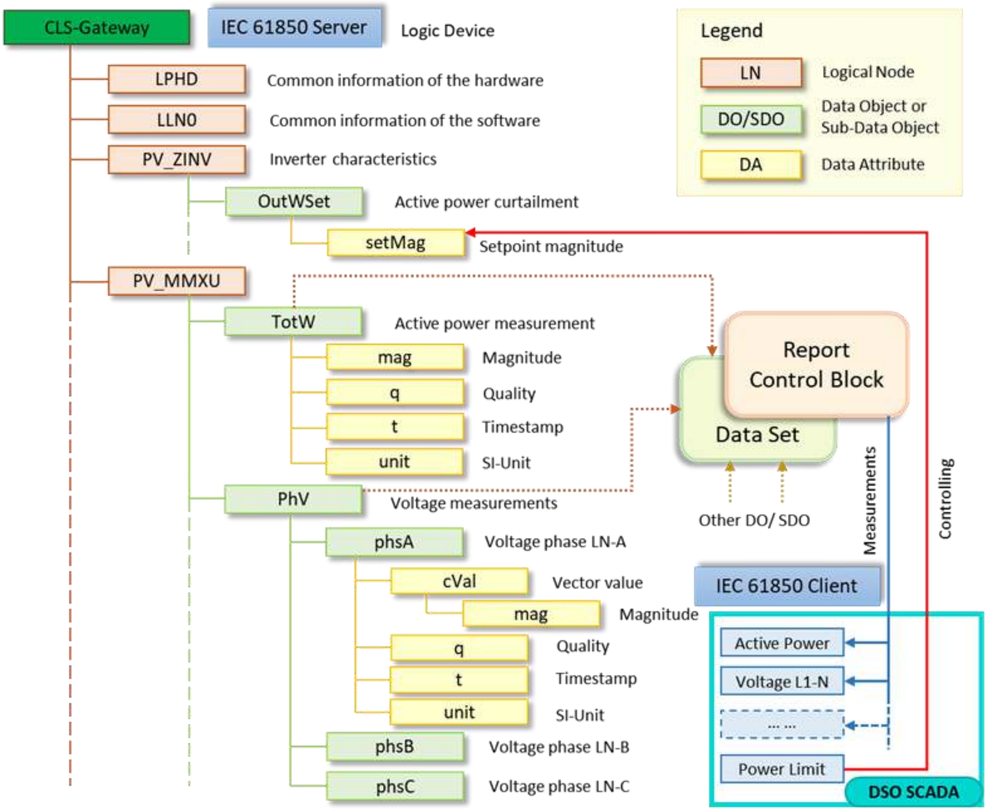



**Figure 20:** Integration of PV systems into Smart Grids with IEC 61850 Data model. This diagram shows the hierarchical structure of an IEC 61850 data model with logical nodes (predefined elements, e.g. PV_MMXU for PV inverter measurements and PV_ZINV for curtailment settings). The IEC 61850 data model enables self-description of systems with which automatic registration of DER at the DSO-SCADA or a national DER registry becomes available.

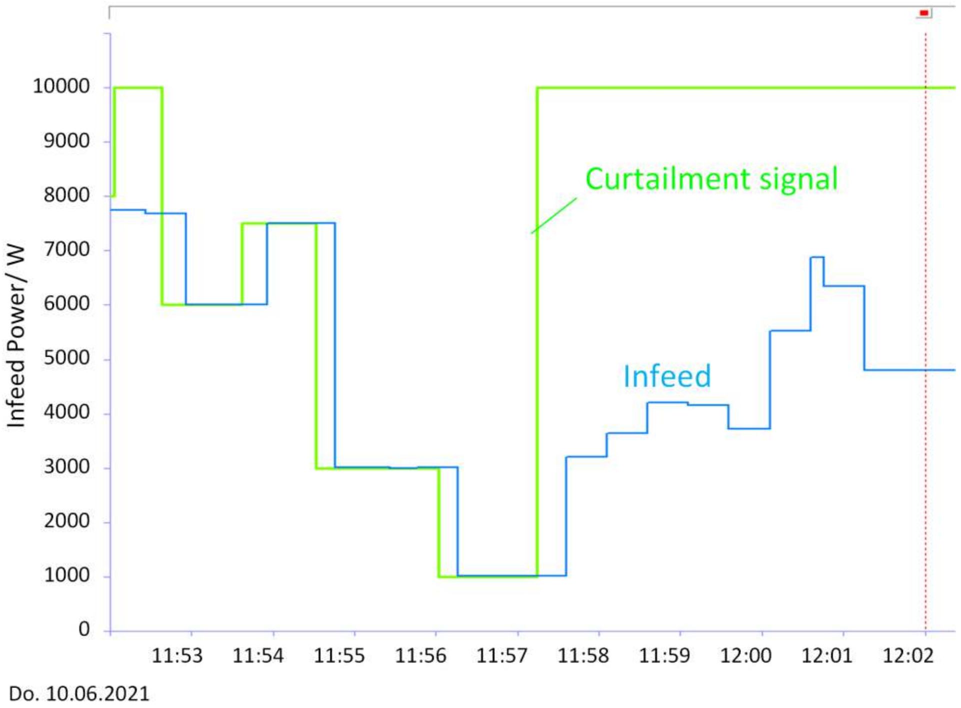



**Figure 21:** Demonstration of PV curtailment direct in DSO control center with the Smart Meter Infrastructure. The blue curve presents measured PV infeed power, which is transmitted to the SCADA every 10 seconds; the green curve indicates power curtailment commands send by the grid operator to the PV inverter via SMGW and CLS-Gateway. It can be seen that the curtailments are executed within 20 seconds and the inverter did behave correspondingly to the curtailments. The telecommunication was performed via Ethernet cable connection in this test case.

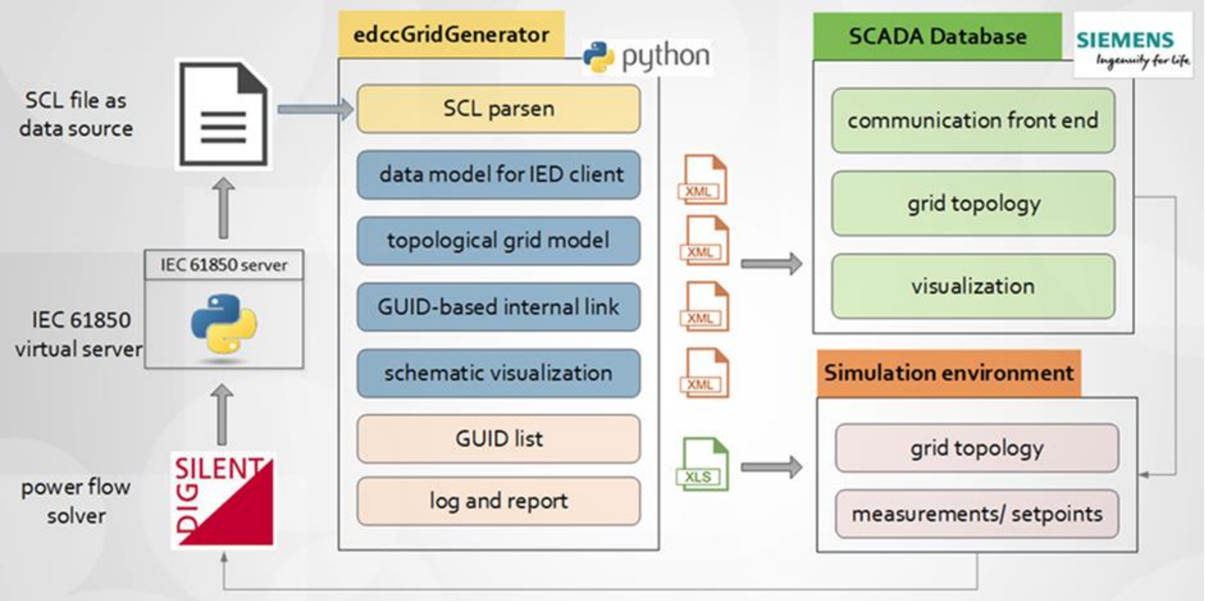



**Figure 22:** Application of automated registration of PV systems at a distribution control center (Scada Database). The IEC 61850 data model is stored in the SCL file. From the SCL File the necessary data extracted and the different CIM – XML files are created for the IED client, the topological grid model the GUID-based internal link and a schematic visualization of the PV system with its measurement values.

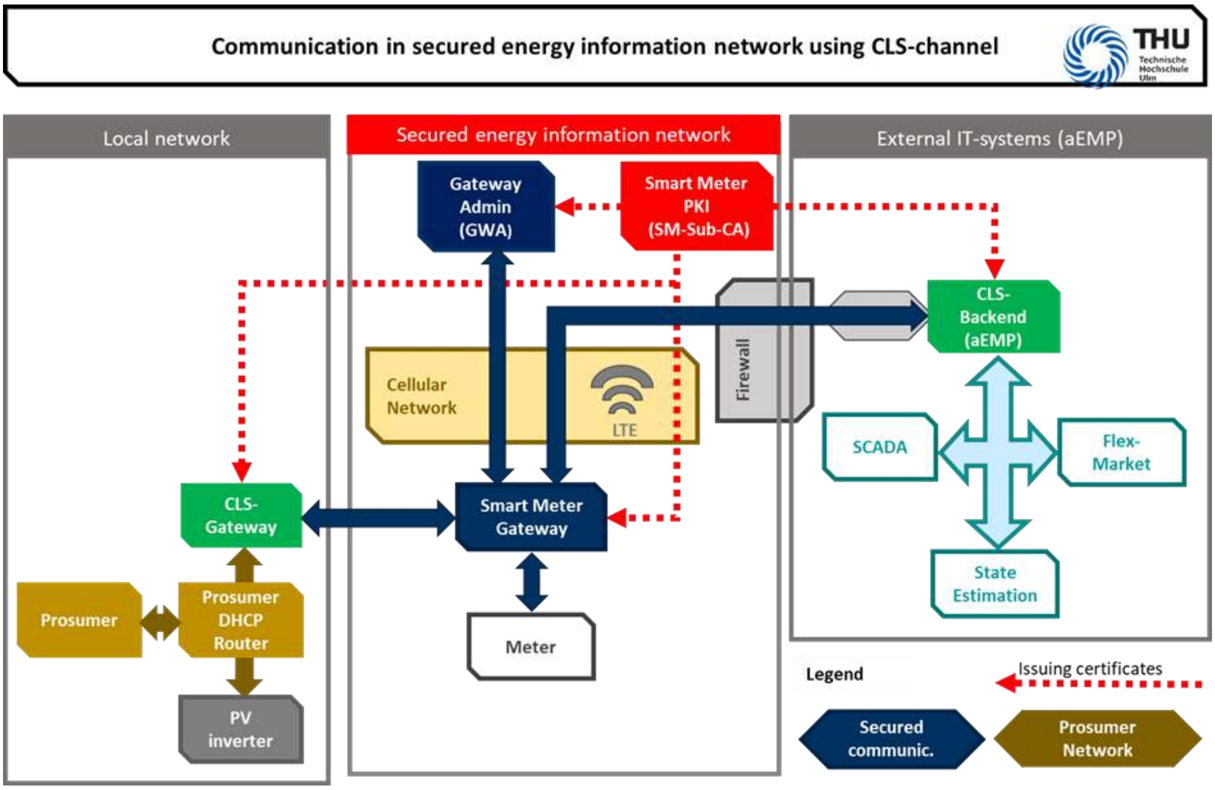



**Figure 23:** Final state of the implemented Smart-Meter-Infrastructure including CLS-systems at the Ulm University of Applied Sciences. This setup also illustrates the complexity of the whole system regarding the coupling of different communication networks, implementation of data interfaces and IT-security concerns. The basic security measure is the introduction of a public key infrastructure (red) which ensures the identity of the different communication participants. In addition, the communication channels are TLS encrypted. Both are not the case for the integration of the local Prosumer network that is needed for the connection between CLS-Gateway and the PV-inverter or other active energy systems.

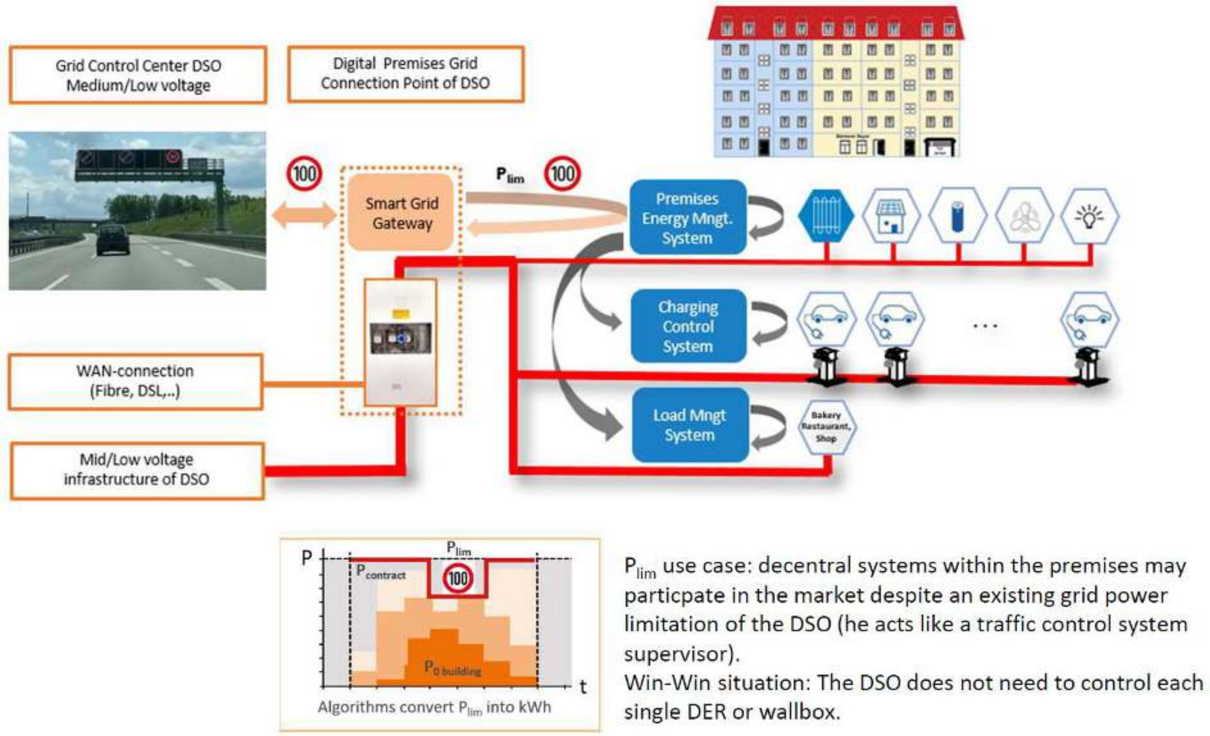



**Figure 24:** Another new solution for remote curtailment of decentralized local PV-Systems is the digital grid connection point (Digitaler Netzanschluss) which has been developed by the DSO of the city of Munich (SWM) and further defined in a technical rule [24]. Instead of a direct communication with individual energy systems, the digital grid connection point transfers a schedule of positive and negative power limits to each grid connection point. These power limits are read by the local energy management system, which ensures the control behind the grid connection point. With this setup the network operator has no active role in the private premises.

The C/sells project demonstrated the capabilities of digitalisation of the distribution network to host decentralized renewable energy systems [24].

Based on the definition of the German Smart Meter Infrastructure [30] [31] and the introduction of a standardized data model for distribution grids [26] [27] [25] a bidirectional communication between grid control and DER enables state estimation and curtailment in the distribution network. With the expected high numbers of future installed PV systems in the low voltage network these functions are also needed for residential PV systems. With the introduction of the digital grid connection point [32] an additional concept was demonstrated defining temporal limits for load and feed in power of the grid connection point.

With the results of the C/sells demonstration project Distribution System Operators can choose between an active curtailment based on bidirectional communication with the DER or the passive concept of the digital grid connection point.

With the digitalisation of the distribution network also additional services like market coupling of DER or automatic registration of DER become available and should be integrated in the overall digitalisation concept.

## 4.5 PV local reactive power compensation

Authors: M. Cauz, L. Perret (PLANAIR)

**Objective:** Integration and simulation of a controller to compensate the reactive power of a factory by driving the inverters of its photovoltaic power plant.
**Field area /laboratory test:** The project was carried out within the framework of the private electricity network of a chocolate factory in Switzerland (Camille Bloch SA).
**Considered PV systems:** Validation tests were carried out using the site's two 141kWp and 168kWp PV systems.
**PV inverter functions:** All 10 inverters (2x ABB TRIO-20.0 and 8x ABB TRIO-27.6) for both PV plants were remotely controlled by a central unit through Modbus. (External control of Q/ Cosφ)
**Main results:** In actual operation, the inverters have demonstrated their ability to compensate the reactive power demand by the production equipment according to two types of regulation: either by maintaining a fixed value of reactive power or by maintaining a Q/P ratio.

In Switzerland, most of the DSOs charge the reactive power when it exceeds a certain ratio of active power extracted from the network, usually set at $Q > 0.5 \cdot P$ which roughly corresponds to a power factor of 0.9. However, many industrial sites are setting up photovoltaic systems that have the effect of reducing the amount of active power extracted. This leads to a reduction in the amount of reactive power that the industrialist can feed back into the grid without being billed. Thus, without appropriate corrective measures, the financial impact of installing a PV plant can be significantly reduced. This project demonstrated the feasibility of using PV inverters for the generation and/or consumption of reactive power at an industrial production site. The pilot site is equipped with 8 inverters ABB TRIO-27.6 and 2 inverters ABB TRIO-20.0, which communicate in Modbus RTU for transferring production data to the controller.

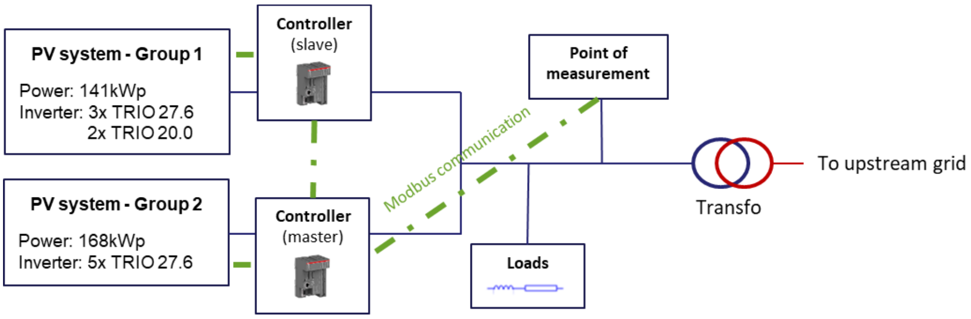



**Figure 25:**Simplified electrical schematic of the pilot site

Theoretically, the TRIO-20.0/27.6 inverters have a semicircular reactive power capability. However, controlled by Modbus, there are 2 different limitations:

- When the reactive power is expressed as a percentage of the nominal power, the current and voltage can be shifted out of phase within a range of 80% to 100% of the nominal power (in both directions).
  - ⇨ Maximal reactive power compensation: 208kVar (16kVar for the TRIO-20.0 and 22kVar for the TRIO-27.6).
- When the reactive power is expressed through a fixed power factor, it can vary within a range of 0.8 to 1 (in both directions).
  - ⇨ Maximal reactive power compensation: 170kVar (13.32kVar for the TRIO-20.0 and 18kVar for the TRIO-27.6).

Note that more recent inverters make it possible to adjust the power factor to all its admissible values, i.e. between 0 and 1, thus allowing greater compensation per inverter. To control the inverters of both PV plants, two ABB AC500-eCo model PM566-Eth APIs were used. For centralized system management, one of the two controllers was designated as the master and the second as the slave. The implemented controller is described in the figure below.

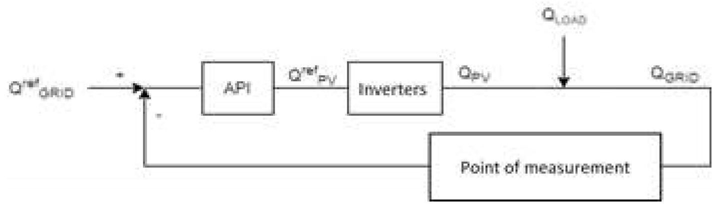



**Figure 26:** Pilot Study Control Diagram

The reactive power value measured at the point of measurement is compared at the system input to the desired value $Q^{ref}_{GRID}$. Knowing the error between these two values, the controller then sends an instruction to the inverters to offset this difference. The reactive power generated by the inverters is added to the plant load to provide the $Q_{GRID}$ value corresponding to the value measured at the point of measurements. With this controller, the setpoint transmitted to the inverters allows the measured reactive power value to be maintained at the desired value while automatically taking into account a change in the plant load.

The implemented APIs can be parameterized with different control modes and operating points in order to adapt to different situations and tariff schemes.

- The system has two control modes:
  - Permanent: The compensation system is permanently ON or OFF.
  - Automatic: The compensation system activates automatically when the Q/P ratio reaches a defined threshold.
- The system has two operating points:
  - Fix: The system maintains a fixed value of Q at the point of measurement.
  - Dynamic: The system maintains a fixed ration x = Q/P where x is a parameter.

Several tests have demonstrated the ability of the system to both compensate for a fixed value of reactive power and maintain a maximum Q/P ratio, as shown for example in Figure 27. These tests have also shown the requirement for access to certain measures, in particular for dynamic compensation. With the data available on the pilot site, it seems preferable to operate such a system in continuous mode in order to balance the reactive power and maintain it at a target value. The impact on the solar output is, in the context of this study, negligible, but can be limited in other situations either by oversizing the inverters or by restricting the reactive power compensation of the inverters (if it is estimated that the PV output is more important than the reactive power generation).

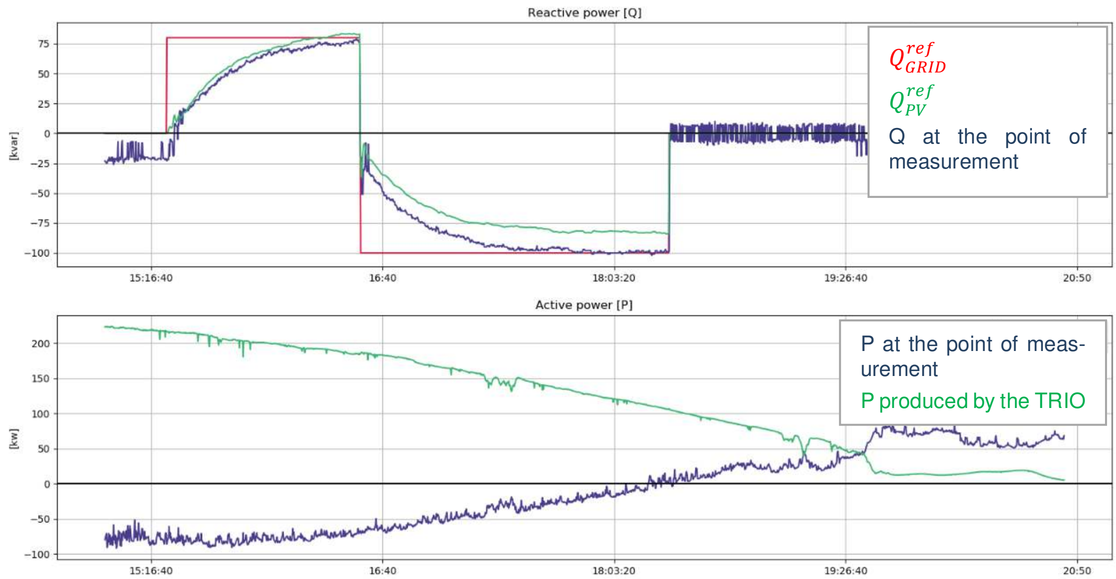



**Figure 27:** Illustration of the system operation with fixed reactive power compensation

**Conclusion, lessons learned:**

Reactive power compensation is an issue that mainly impacts industrial sites and medium and high-voltage power transmission. During this study, we focused our work on the first target audience through a pilot site representative of these industries. In these industries, the reactive power induced by the equipment is generally regulated by means of capacitor banks. Apart from the financial cost they generate, the latter have few drawbacks if they are well dimensioned. Due to their design and as shown in this study, photovoltaic inverters can provide a similar result to capacitor banks while providing additional functionality.

- Larger operating range: Inverters can compensate for any continuous value within their operating range.
- Fixed or dynamic compensation.
- Additional service: Some inverters can be used independently of the solar production, for example at night, to provide ancillary services (potential additional income).

To take advantage of the use of inverters for reactive power compensation, it is important, on the one hand, to properly proportion the nominal power of the inverter so as not to limit the produced active power. On the other hand, the controller design is particularly important in order to best meet the site's reactivity requirements, especially in terms of responsiveness and control.

Despite these additional functionalities, reactive power compensation using PV inverters remains complementary to compensation banks and only adapts to specific sites as shown in the following figure.

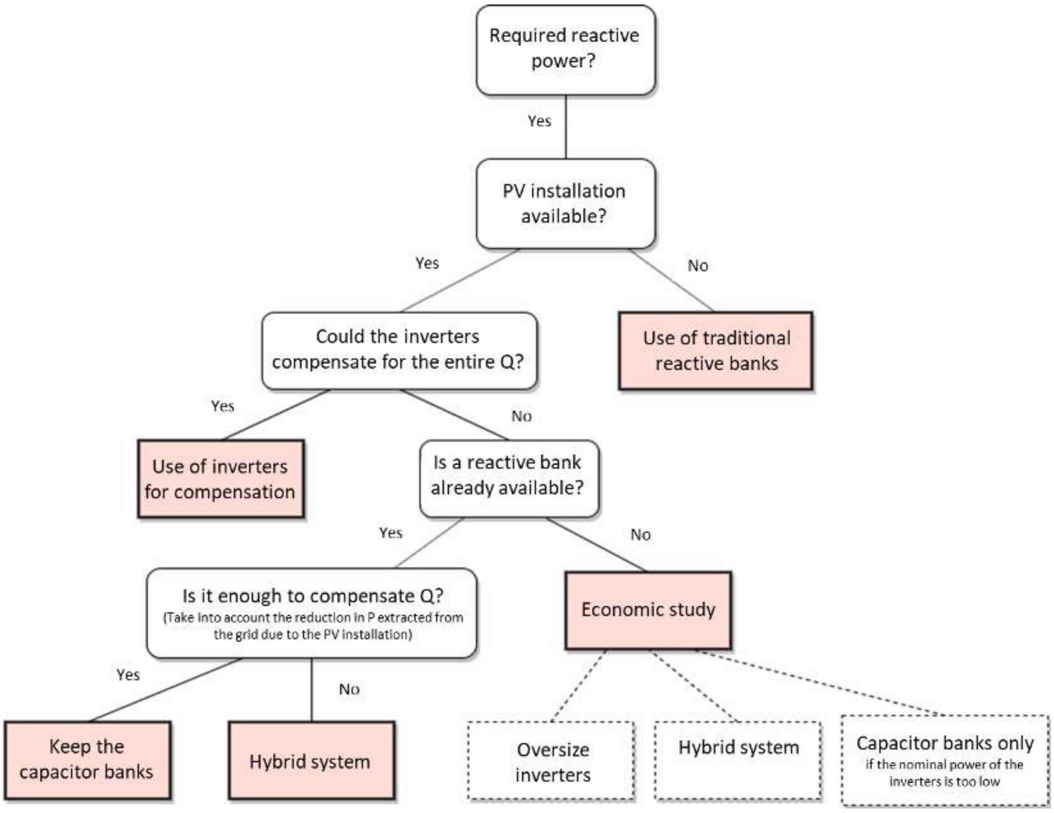



**Figure 28:** Conclusion of the pilot study

In conclusion, the integration of a standard regulator within the inverters would make this compensation solution particularly attractive to industrialists and increase the potential for ancillary service support.

## 4.6 Remote PV reactive power control for voltage support at the Transmission – Distribution interface

Author: M. Kraiczy, S. Wende von Berg, (Fraunhofer IEE)

**Objective:** Control of Q exchange at the Transmission-Distribution interface (in Germany: EHV/HV-interface) by Q provision of PV and Wind power plants directly connected at the HV-level (* in Germany the HV-level is mainly operated by Distribution System Operators and is considered as part of the distribution grid)
**Field test region:** EHV level of TSO 50Hertz and HV grid section of DSOs MITNETZ and Sachsen Energie (former ENSO) in the East of Germany
**Considered PV systems:** utility-scale PV at the HV-level. State-of-the-art PV systems in compliance with the German HV grid code VDE AR-N 4120.
**PV inverter function:** External control of Q/ Cosφ
**Main results:** Successful field test showed the control of up to 40 MVAr from distributed Wind and PV power plants at the T-D interface. Reactive power provision from distributed RES (here: HV-level) have a significant potential to support the voltage regulation also at the transmission level.

According to the network development plan of the German TSOs, a minimum additional Q compensation demand of 38 to 74 Gvar is identified for the German transmission level until the year 2035 [33]. The main drivers for the additional Q compensation demand are the ongoing decommissioning of nuclear and coal power plants at the transmission level, the expansion of transmission capacities, and increased transport distances. Discussed additional sources for Q compensation in the German power system are, for example, the installation of additional Q compensators, the modification of disused power plants for phase shift operation, the use of HVDC converter stations, and the utilization of the Q support capabilities of distributed energy resources [34].

“In the national research project SysDL 2.0 the utilization of RES’s reactive power in order to optimize 110 kV distribution grids and supply ancillary services for the transmission grid was investigated. Within the project, new solutions were developed, tested and applied in a field test” [35]. Therefore, several use cases such as voltage limit requests and reactive power demand at T-D interface, redispatch validation, local voltage stability, minimization of active power losses, and local congestion management were analyzed and discussed.

The presented field test took place in spring 2018 and focussed on the control of the Q exchange at a Transmission-Distribution (T-D) interface (here: 380 kV/110 kV transformers) in the investigated grid section by Q support of PV and Wind power plants at the HV-level (reactive power demand use case). The field test area of the German DSO MITNETZ covers a 110 kV grid section in the south of Brandenburg, Germany, and had in 2018 an installed capacity of approx. 1100 MW wind power and approx.600 MW PV power. For the field test, 13 Wind and PV power plants with an installed capacity of about 490 MW are selected , even though, only 6 power plants were chosen by the optimization algorithm to contribute for the field test Q demand. The considered DER plants comply with the German grid code VDE AR-N 4120 and are remotely controllable from the DSO control center.

- The field test procedure is explained as follows:TSO choose Q set-point from forecasted Q-flexibility range at the T-D interface
- DSO receives Q set-point at the T-D interface from TSO (here: Q = 0 Mvar, magenta solid line, Figure 29, top). The central reactive power optimizer (reactive power assistance system) developed in the SysDL 2.0 project determines the optimal Q set-points for the individual RES at the HV-level
- Operator entered Q set-points for the RES manually in steps of 3 MVar per 2 Min (colored solid lines, Figure 29, bottom) and the RES respond to the central Q set-points (colored dashed lines, Figure 29, bottom)
- After 30 Minutes the desired Q set-point at T-D interface is reached with the support of RES Q provision (magenta dashed line, Figure 29, left)

**Conclusion, lessons learned:**

- The successful field test showed the control of up to 40 MVAr from up to 6 distributed RES plants.

- PV and Wind DER could realize the central Q set points mainly with good accuracy, but partly with different delay and gradient limitations.
- Optimal power flow methods are capable of providing optimal settings for DER in real-time grid operation.
- The open-loop concept was useful in the field test to prove the developed Q management concept, but for a continuous grid operation, an automated setpoint specification is necessary. The manual input of the set points for the RES, were difficult and stressful under the timing conditions of entering new set points for all six power plants every two minutes.
- It could be shown that with a reactive power assistance system, grid services from RES at the distribution level are applicable.
- Standardized data models enabled access and the exchange of network data and results with the control rooms
- Ancillary services from distribution grids house great potential to compensate the reactive power demands of the distribution level

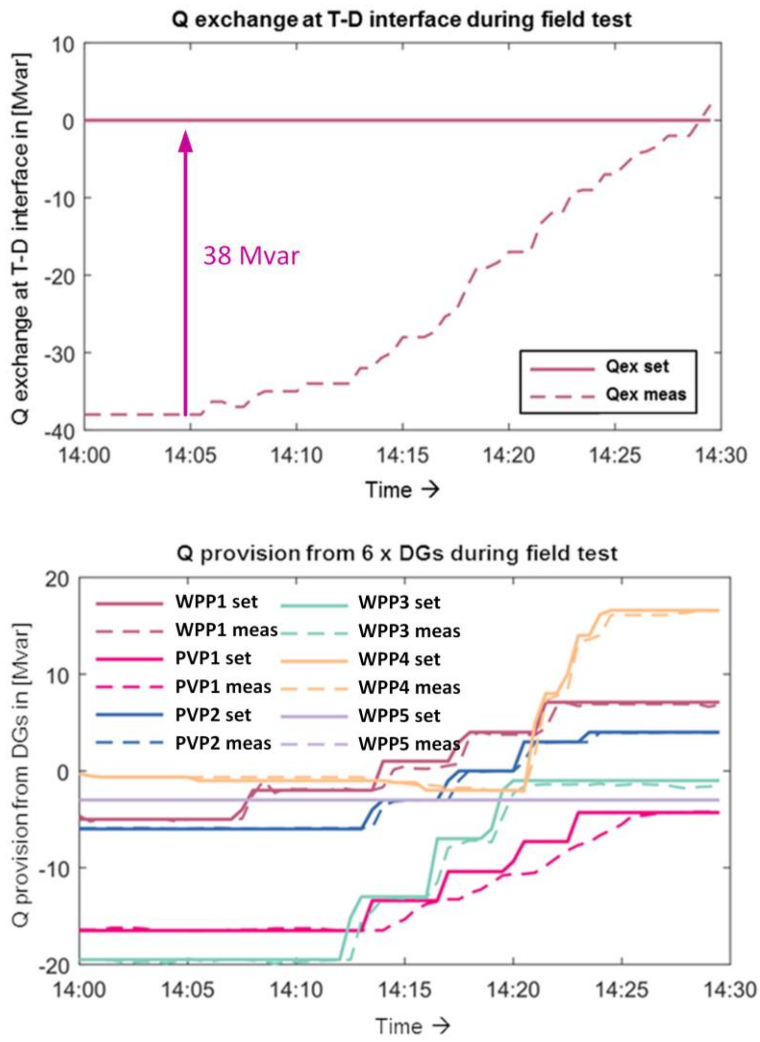



**Figure 29:** Results from field test on 1st March 2018 (Source: **[36]**). Top: Measured Q exchange (dashed line) and TSO Q set-point at T-D interface (solid line). Bottom: Measured Q provision (dashed lines) and central Q set-point (solid lines) of Wind (WPP) and PV plants (PVP).

## 4.7 PV storage hybrid system for 100% solar power on the remote island of St. Eustatius

Authors: A. Knobloch, D. Premm (SMA)

**Objective:** PV storage hybrid systems provide ancillary services that substitute synchronous generators
**Field test region:** 12,45 kV medium voltage grid of the remote island of St. Eustatius
**Considered PV storage systems:** commercial utility-scale PV plus battery storage hybrid system with string and central inverters, managed by a hybrid plant controller
**Applied inverter functions:** Grid forming voltage and frequency control, Diesel-Off mode, energy shifting, frequency containment and restoration, fault-ride-through, uninterrupted power supply
**Main results:** Today's utility-scale grid forming PV storage hybrid systems provide ancillary services that allow a 100% solar power generation and a substitution of conventional Diesel generators in island grids, thereby providing a stable and secure grid operation with a superior power quality compared to public electricity grids.

PV hybrid systems on remote islands pave the way to the hybrid generation control in future public electricity grids. Years of successful operation and experience with utility-scale PV hybrid systems in island power grids with a high share of renewables demonstrate that synchronous generators can be substituted by power electronic converter systems with similar and yet even better grid stabilizing capabilities. Thereby, a superior power quality, a high grid availability and a substantial reduction of fuel consumption as well as CO2 emissions are achieved, providing a stable and reliable grid operation at normal grid imbalances and even at critical power system failures [37], [38], [39].

In today's PV hybrid systems, that are at times 100% solar powered, PV and battery storage systems as well as plant controllers contribute to a stable and secure power supply. Here, grid supporting PV inverters are mainly responsible for the maximum possible photovoltaic solar energy harvesting. They operate the PV generators at their maximum power points (MPP) and support the grid voltage and frequency in case it is necessary, under normal grid state as well as in case of a fault or an emergency. Therefore, the available power, energy, and short circuit current capabilities of conventional PV inverters are used, ensuring that solar energy is produced in the most cost-efficient way [39].

The essential grid stabilizing mechanisms, analogous to conventional synchronous generators, are provided by grid forming control system solutions, based on battery storage inverters and an appropriate hybrid power plant control. Following a grid forming control strategy, an inverter acts as a voltage source, where the output voltage is controlled and the output current flow results by load or grid conditions [39]. For the provision of an effective control action whenever needed, grid forming systems require a proper amount of power reserves, energy storage, and short circuit current. These quantities need to be carefully designed and the relevant control functions need to be carefully parametrized depending on the functional objectives, power system properties, on-site protection schemes and under the consideration of the grid supporting capabilities of the remaining generation, load, and storage units but also other factors. In addition, an overlaid hybrid plant controller provides management and control action for the restoration of the voltage amplitude and frequency to desired reference values with an adjustable load share between different inverters.

State of the art PV hybrid systems are among others capable to provide the following services and to contribute to:

- **grid voltage and frequency** control synchronously to other voltage sources but also in standalone operation,
- **instantaneous response** to grid events,
- **automatic load sharing** between parallel voltage-controlled grid forming inverters,
- **frequency containment and restoration** by primary and secondary active power reserve provision,
- **voltage support** by reactive power provision,
- **fault ride through** with instant short circuit current, a fast post fault voltage restoration and an appropriate overcurrent protection of inverters,
- **uninterrupted power supply** at unintentional islanding by immediate backup functionality,

- **diesel-off mode** and intended islanding for 100% inverter-based power supply,
- **black start capability** and synchronization to external grids,
- **energy shifting** for maximizing renewable energy use,
- **renewable ramp rate control** for smoothing renewable power fluctuations.

The following selected results of extensive practical field tests demonstrate the performance of state-of-the-art utility-scale PV storage hybrid systems.

Since November 2017 solar energy covers 46% of the electricity demand of St. Eustatius, an island in the Caribbean with about 4,000 inhabitants. Grid forming Sunny Central Storage battery inverters allow to operate the island grid for 10.5 hours in Diesel Off-Mode with 100% solar power fraction. This means that the synchronous diesel generators can be switched off completely during the day - unnoticed by electricity consumers. A 5.9 MWh li-Ion storage facility has been integrated for energy shifting and grid services. The SMA Hybrid Controller is responsible for real-time energy and power management and synchronizes diesel and battery operation intelligently and fully automatically [37], [40]. Figure 30 depicts the St. Eustatius PV hybrid system setup.

Figure 31 (left) shows the power flows in the PV hybrid system on a typical day. At night, diesel gensets cover the load demand. In the morning hours, the solar system reduces the power coming from the gensets, until they reach a minimum load level. From this point, the batteries are charged until a sufficient energy amount enables to switch off the diesel engines. Hereafter, the load is completely supplied by PV plus storage without power, energy, and inertia of the diesel gensets. The batteries compensate the difference between load and PV by charging or discharging the storage. When the batteries are fully charged, the solar power is curtailed to the load demand. In the evening, the power provided from the batteries is slowly increasing due to the reduced solar power (energy shift) and finally the diesel gensets start again to provide the energy needed during the night. At night, grid-forming battery inverters still run in parallel for optimized genset operation and for uninterrupted backup purpose in case of a genset outage.

The system is capable to compensate huge and dynamic PV power fluctuations, typically caused by exceptionally fast-moving clouds in this region, within milliseconds. Grid frequency observations (see Figure 31, right) in standalone operation show that battery storage inverters compensate even power imbalances larger than load demand (solar power ramps of 2,5 MW per 70 s at 2 MW load) immediately and without a notable frequency deviation.

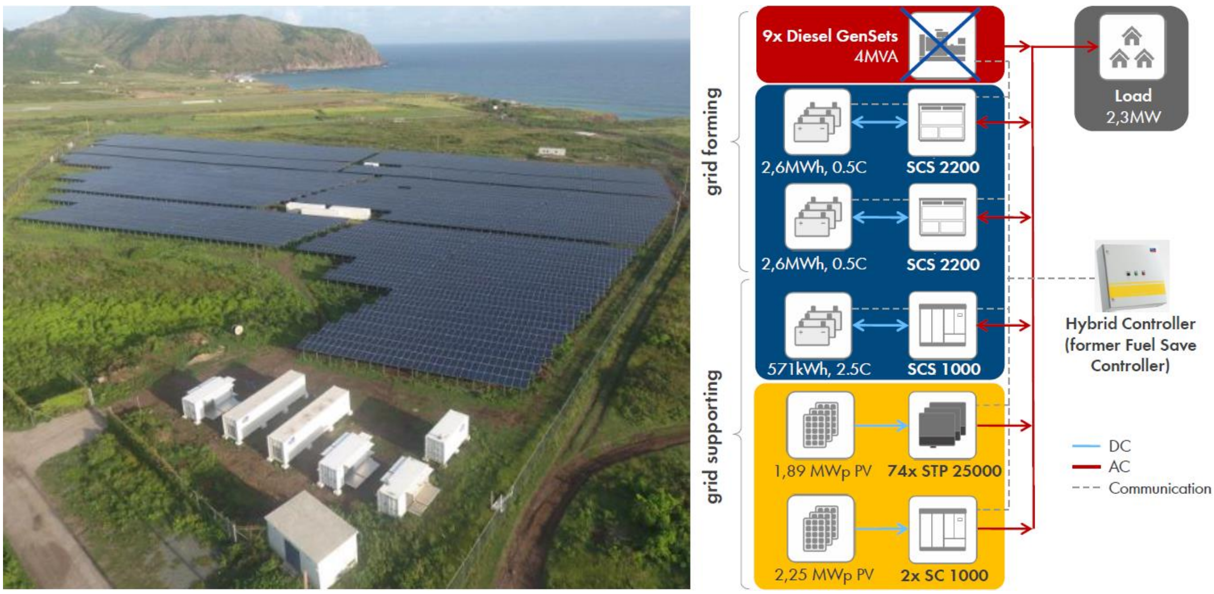



**Figure 30:** St. Eustatius PV hybrid system. Left: PV storage system view from above. Right: system setup.

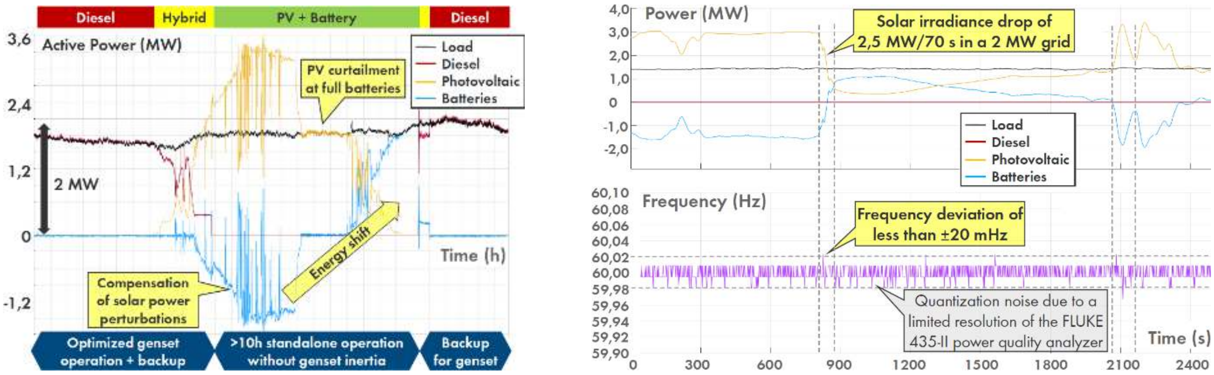



**Figure 31:** Load coverage by PV, battery storage and diesel genset on the island of St. Eustatius. Left: Load coverage in the course of the entire day. Right: Frequency sensitivity to irradiance perturbations.

The St. Eustatius PV hybrid power plant, with its conventional and inverter-based generation, combined with battery storage and a parallel operation of grid forming and grid supporting control, proves that a stable operation of power grids is feasible without conventional must-run-units and their inertia and fault current contribution [39]. Even at emergency situations caused by grid faults or power system splits, with a huge power imbalance between generation and demand and combined with a stepwise inertia decline in the remaining areas, voltage and frequency deviation and restoration time are superior compared to conventional mechanisms in today's European power grids.

On the island of St. Eustatius, a power system split scenario was under investigation by a sudden disconnection of the complete conventional genset generation, which fully covered the load before failure (for detailed test setup see [37]). Simultaneously, the complete genset inertia was disconnected. Figure 32 (left) depicts the system frequency, active power measurements and setpoints provided by the plant controller. The result indicates that grid forming devices instantaneously take over the load with an equal share immediately providing very fast containment reserves with dynamics similar to inertial response. After 500 ms the hybrid plant controller detects the diesel-off-situation and starts providing frequency restoration reserves by modifying the battery inverter's active power setpoints. In less than 3 sec after genset disconnection, the frequency is restored back at nominal value. The maximum frequency deviation of the 60 Hz grid reached $\Delta f \approx$ -0,65 Hz with a rate of change of frequency (RoCoF) of about $df/dt \approx$ -2,5 Hz/s. The frequency nadir and the RoCoF depend on the inverter's control parameter settings as explained in [37].

Successful acceptance tests with forced short-circuits at the medium voltage grid of St. Eustatius demonstrate the ability of grid forming battery inverters for fast clearing times and fast voltage recovery, both with conventional gensets in parallel or in Diesel Off-mode, shown in Figure 32 (right).

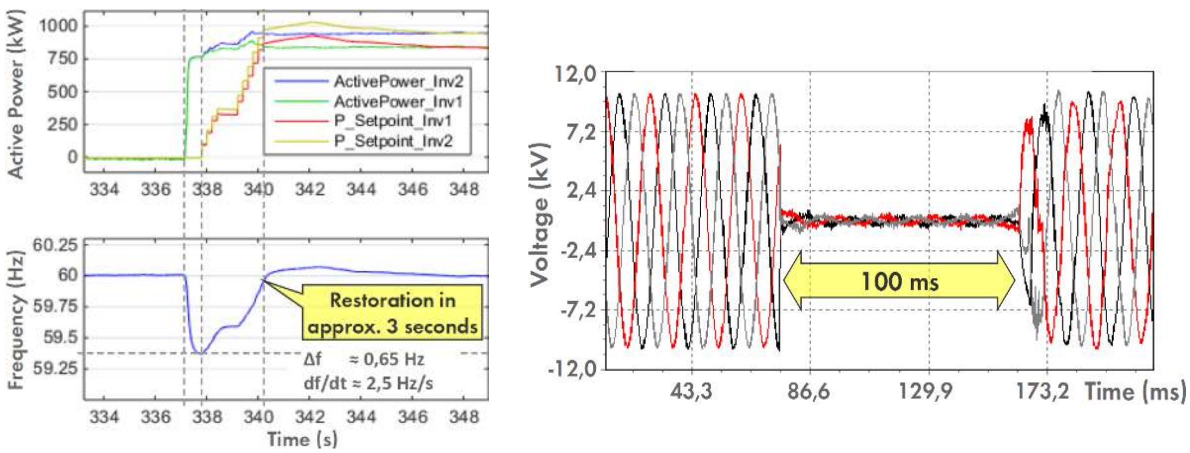



**Figure 32:** Dynamic response of the grid forming battery storage system to grid events. Left: Frequency containment and restoration at unintended full genset disconnection. Right: Fast fault clearing and voltage recovery after a 3-phase short-circuit fault.

## 4.8 One hour with 100% renewable power - islanding operation test of the German community of Bordesholm

Authors: A. Knobloch, D. Premm (SMA)

**Objective:** power supply of the community of Bordesholm with 7500 inhabitants for almost one hour only with the help of decentralised renewable sources and a large-scale battery

**Field test area:** community power grid of the German village Bordesholm with 3-4 MW power consumption at the MV-level

**Considered system:** renewable energy sources from residential and commercial PV, biomass, and a large-scale battery system

**Applied inverter functions:** Grid forming voltage and frequency control, seamless intentional islanding, synchronisation to public power grid, black start, islanding detection

**Main results:** A stable and secure grid operation with 100% inverter penetration and completely without conventional must-run-units is feasible also in public electricity grids. Grid forming operation in public power grids requires framework enhancement.

Commercially available, large-scale battery storage system technology is equipped with functions that allow a stable and secure emergency power supply of grid areas after an intentional or unintentional disconnection from public electricity grids. Additionally, black start functionality enables a fast grid restoration within seconds, and a seamless grid synchronization and connection to an external grid.

During a test on November 11, 2019, the German village Bordesholm, with 7500 inhabitants and a power consumption of approximately 3-4 MW, was successfully disconnected from the European electricity grid without interruption. The experimental test setup together with a detailed test description and test results were published in [41]. For a duration of one hour, the whole village was completely powered by renewable energy from photovoltaic and biomass power and from the 12,5 MW / 15 MWh large-scale battery storage facility, that is usually used for primary balancing power reserve service provision. For the intentional islanding test, the storage facility was operated in grid forming mode and equipped with black start as well as with grid synchronization capabilities. The PV inverters in the micro grid were unchanged, operating in current-controlled grid supporting mode with still activated islanding detection mechanisms. After one hour of micro grid operation the Bordesholm village was successfully synchronized and seamlessly re-connected to the public grid.

Figure 33 shows the frequency measurement in public grid operation (red), in micro grid operation (green), during grid synchronization (blue) as well as during an intended blackout of the battery storage facility with a subsequent black start sequence, followed by the grid connection with a duration of less than 20 seconds. In micro grid operation the grid frequency quality is superior compared to the frequency quality in the European power grid.

It is important to mention that during the islanding transition and the whole islanding operation of the micro grid the PV power plants remained connected to the micro grid, without being disconnected by active and passive islanding detection mechanisms. The experiment results demonstrate the capability of grid forming inverter systems to ensure a stable operation of grid following loads and generators at intended or unplanned islanding of power grids.

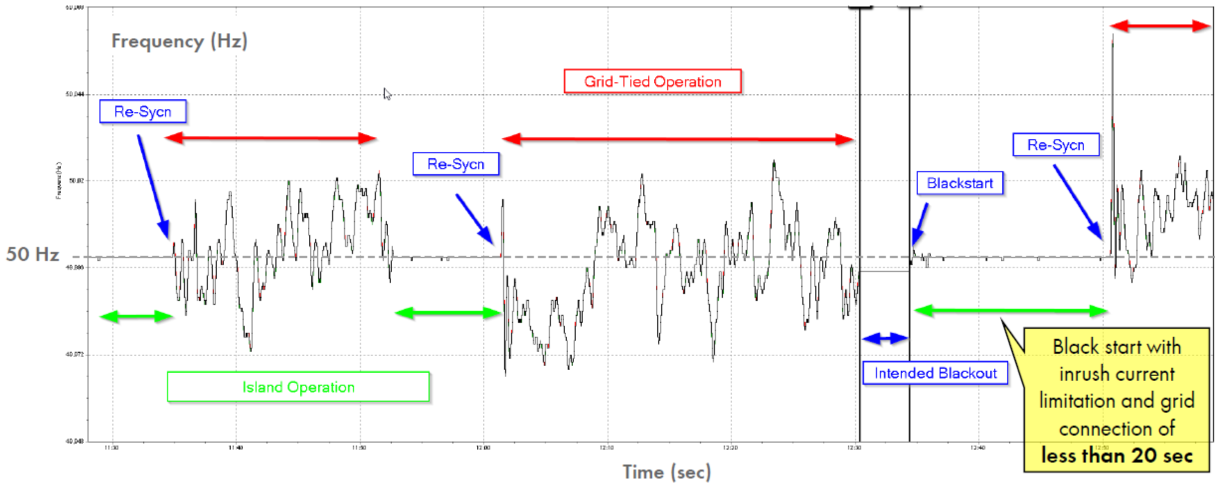



**Figure 33:** Grid frequency of the Bordesholm village islanding tests with a seemless transition from public grid connection to micro grid operation and back and a fast black start of the battery storage plant.

Pioneering hybrid power system projects on a Megawatt-scale like in the German village Bordesholm or on the remote island of St. Eustatius prove that a stable and secure grid operation with 100% inverter penetration and completely without conventional must-run-units is feasible also in public electricity grids. To encourage voltage-controlled grid forming inverter operation in public grids, grid code modifications and an enhancement of the economic framework are very important in the upcoming years.

Today's grid supporting PV systems provide various functions for voltage and frequency support, that enable a stable grid operation with very high inverter penetration rates. However, grid following and grid supporting inverters still rely on an existing grid voltage and frequency that is provided by a proportion of grid forming must run units together with a proper amount of control power and energy for effective control action at any time. Based on present economic incentives, PV power generation still focuses on the highest possible energy harvesting and its precedential grid injection. Therefore, no grid forming operation, no energy storage and no overload capabilities are needed, what made PV solar power generation the lowest cost power source in many regions of the world [40].

To overcome the dependencies on synchronous generators, PV system technology can be enhanced with advanced grid supporting and even grid forming capabilities and provide additional ancillary services in public power grids. This could require a continuously derated PV generator operation, overload capabilities or additional energy storage. In the most energy markets such a PV system design does not pay off today. New economic incentives for advanced ancillary services with low and controllable risks for PV plant owners could help to stimulate technology innovation, to accelerate the massive grid integration of renewables and to reduce the costs for grid enhancement.

In addition, the existing grid codes are usually designed for current-controlled, grid supporting inverters. The advantageous behaviour of grid forming inverters in public grids is currently inhibited by most of the technical rules for grid connected operation. Requirement specification for grid forming inverters is needed regarding to the

- evidence of grid-forming behaviour,
- fault-ride-through behaviour,
- behaviour at operational limits of the inverters,
- prevention of and behaviour at unintended islanding,
- characterization of inverter-based inertia,
- common test procedure and quality criteria that are harmonized on an international level.

## 4.9 PV hybrids in the island power system of El Hierro

Author: R. Guerrero Lemus.

**Objective: Increasing the share of renewable energies in El Hierro by coupling a PV-battery hybrid system to the hydro-wind power plant**
**Field area: El Hierro island**
**Considered PV systems:** utility PV system size, commercial
**Applied inverter functions: i.e.** Grid forming function, power-frequency response
**Main results:** some initial results of the analysis, process under licitation

El Hierro Island is an isolated power system with an annual peak demand of 8,22 MW in 2020 (31/12/2020, 19:13). It is based on a combination of a diesel power plant (14,94 MW nameplate capacity), and a hydro-wind pumping system (11,50 MW wind and 11,32 MW hydro nameplate capacity) that started into operations in mid-2014 (Gorona del Viento S.A.). PV capacity injecting to the grid in El Hierro is small and only has increased recently (311,4 kWp, March 2021) because an early decision of the insular government to favour the construction and service of the hydro-wind power system in relation to other renewable alternatives. Moreover, El Hierro has only one 20 kV / 0,4 kV substation at the Llanos Blancos power plant (LBPP). The power grid has 4 main power lines starting in LBPP covering 114 km and 115 transformer centres.

**Figure 34:** Distribution grid of El Hierro (source: Endesa Distribución S.A.)

Currently, the main concern is that El Hierro would like to be the first Canary island to decarbonise its power generation, but the maximum share of renewables in El Hierro from 2014 to 2020 has been 56,6% in 2018. Indeed, the share of renewables in 2020 reached 41,8%. Then, the insular government understood in 2018 that other new strategies based on the service of new PV capacity was needed to reach the 100% renewable penetration goal.

First studies started considering the integration of a large PV plant combined with batteries, EV charging stations and selfconsumption. Static and dynamic models developed for Gorona del Viento S.A. simulated the expected integration of a new PV-storage system of the insular power grid under extreme conditions for defining the maximum nameplate capacities. The main conclusion was that the maximum capacity of a PV-battery system injecting power to the grid could be 2 MWp PV in the area of the substation, but limiting the injection power to the grid to 1 MW maximum and hybridized with a 1.5 MW / 5.6 MWh battery.

Based on this study, Gorona del Viento S.A. published a call in summer 2020 for defining innovative market-based solutions for integrating a PV-battery system to the hydro-wind power station and, subsequently, increasing the share of renewable energies in El Hierro. The submitters needed to classify their offers in one of the following sections:

- Hybrid system composed by a PV plant on ground and batteries in an area adjacent to hydro-wind power plant: PV capacity limited to 1MW and regulated for serving the hydro-wind power plant.

- Self-consumption PV for the roof of the building where the pumping units are located.
- Battery system to be integrated in the current configuration of the hydro-wind power plant: electricity supplied from the wind farm surpluses to the batteries.
- Floating PV on the lower water reservoir of the hydro-wind power plant.

The main features of the solutions proposed for a higher penetration of renewable energies in El Hierro were mostly based in power electronics:

- Batteries offering precise control of PV and wind power peaks, charge shifts and transition to island mode.
- Active and reactive power control below 1 second.
- Self-sufficiency of ancillary services.
- Voltage and frequency regulation.
- Fast frequency response.
- Grid forming inverters.
- Emulation of synchronous generator.
- Blackout prevention.
- Standard protocols.

The main conclusions of this analysis where useful for defining the characteristics needed in a near future biding process in order to supply a PV-battery system to Gorona del Viento S.A. for increasing the share of renewable energies in El Hierro. The main findings were the following:

- The control system for the PV and batteries' inverters must be integrated in the same platform, guaranteeing services in island mode, short circuit power and power-frequency mode.
- The PV-battery system must be compatible and integrated in the SCADA of the hydro-wind power system, and ready to offer active and reactive power to the grid.
- The system should be tested previously to any purchase in order to check that it will be supportive of the frequency ranges included in the grid codes for insular systems in Spain.
- The equipment to be purchased must be previously tested for high levels of salinity, as the power plant is located in a coastal area.

Finally, the offers about floating PV analyzed made Gorona del Viento S.A. to reconsider its integration in the hydro-wind power system. Any risk of damaging the impermeable surface of the water reservoirs must be avoided. An alternative to be considered in this case will be to partly cover the surface of the reservoir with a fixed structure for placing the PV modules, as it is also valuable in future to avoid the evaporation of the water stored in the reservoirs.

## 4.10 Minimization of harmonic current emissions of a PV plant

Author: G. Arnold, Fraunhofer IEE

**Objective:** Minimization of harmonic current emissions of a PV plant by utilisation of multiple string inverter
**Field area /laboratory test:** Field test at a 1 MW PV-farm in Upper Bavaria, Germany
**Considered PV systems:** Utility/Industrial scale PV plant (974.1 kWp DC, 918 kW AC), consisting of 54 identical string inverter connected to the public 20 kV power grid.
**Applied inverter functions: Special inverter control functions are not activated, only passive behaviour of PV-inverters and grid components is used**
**Main results:** Harmonic current superposition within PV plants with multiple (identical) inverters leads to a minimization of the total harmonic current at the point of coupling, depending on

- PV plant design with e.g. Inverter number, inverter design, cable layout, etc,
- Harmonic order and
- Operating point(s) of the different inverter.

The admissible harmonic current emissions of a PV system / PV plant are often an important limiting factor within the grid code compliance assessment procedure requested prior to grid connection. In order to overcome this issue, traditionally one can either choose a “stronger” point of coupling (POC) with the public network or by adding harmonic filters of the appropriate orders to the PV system. A good alternative to both measures is a detailed analysis of the PV plant design with regard to harmonic emission of the used inverters themselves and especially to cancelling effects in PV plants with a large number of identical inverters.

In the context of this project measurement data of the following industrial scale PV plant in the power range of 1 MWp, consisting of 54 identical string inverters were analysed. Extensive GPS time-synchronized measurement data (over a period of more than one year) is available from the following three measurement points:

- NSHV (Low voltage main busbar - total power of all PV-WR).
- UV 9 (Sub-busbar 9 - total power of six PV-WR)
- WR9.x (Inverter 9.x - power of a single PV-WR)

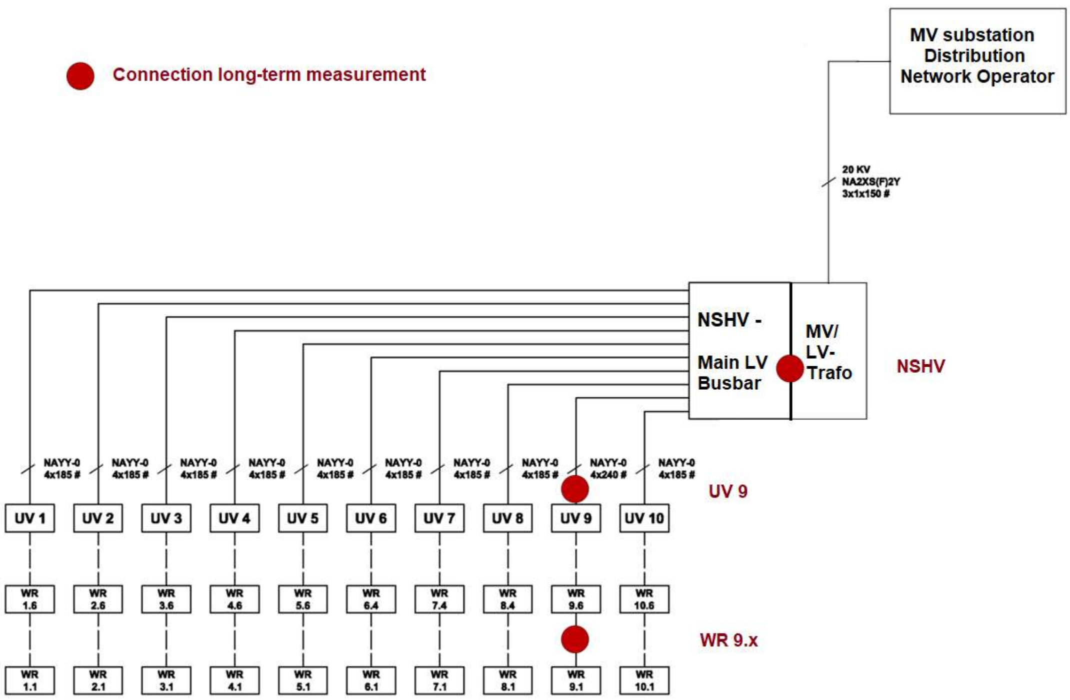



**Figure 35:** General layout of the PV plant incl. representation of the connection points for the long-term measurement

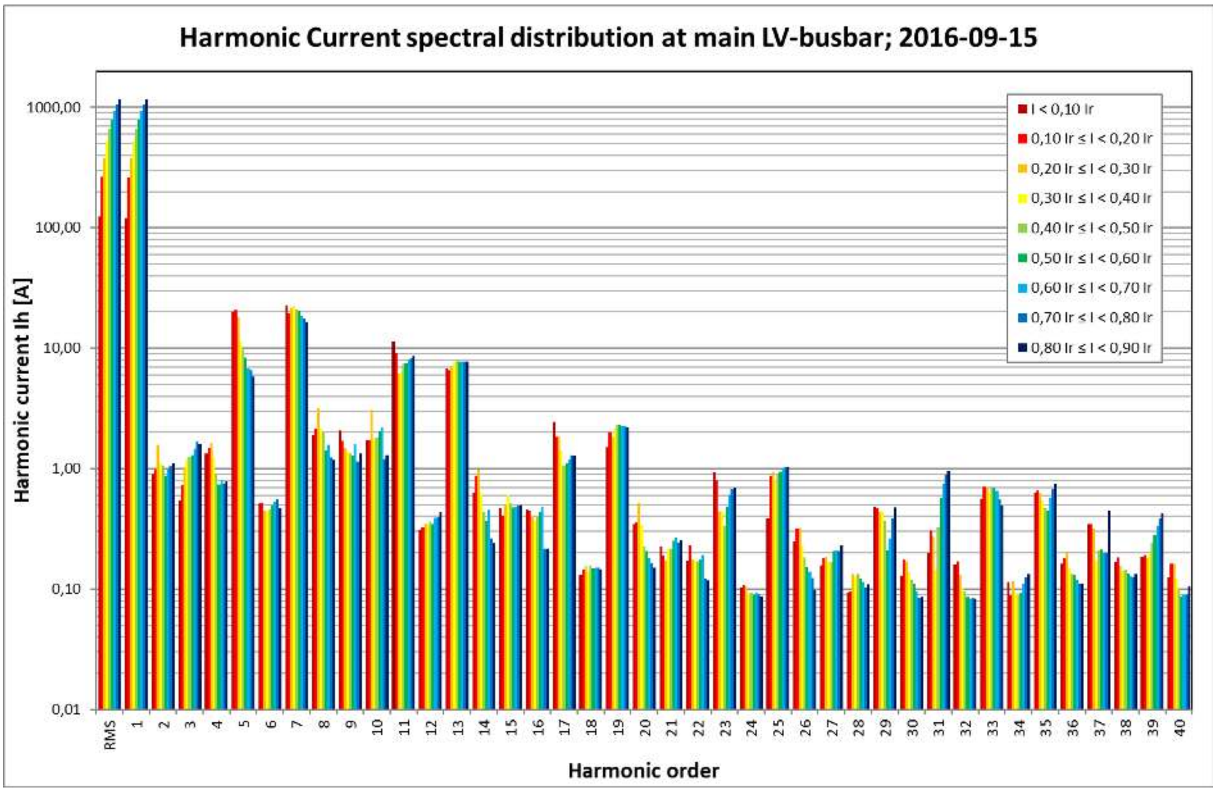



**Figure 36:** Spectral distribution of harmonic currents (Phase L1) of the PV system up to the 40th order (2 kHz) depending on the 99%-quantile of the different rated current /power bins

Figure 36 shows the spectral distribution of harmonic currents at the main LV busbar of the PV system up to the 40th order (2 kHz) based on 1-min-mean values of one exemplary day (2016-09-15). As expected, the harmonic current emissions of the typical converter ordinal numbers (5, 7, 11, 13, 17, 19, etc.) in the spectrum turn out to be significantly higher than harmonic currents with even ordinal numbers or ordinal numbers divisible by three.

**Minimisation due to superposition of harmonic currents**

With the help of time-synchronously recorded measurement data from three grid nodes within the PV system, further analyses had been carried out with regard to the superposition of harmonic currents. Based on the harmonic current emission from a single PV inverter (WR 9.x), the harmonic summation was considered for one of the sub-busbars (UV 9 with six identical inverters) as well as for the LV main busbar (NSHV) of the entire PV system (54 devices).

For the summation of harmonic current emission from n identical PV inverter, the following equation was used analogue to IEC 61400-21 ed.2:

$$I_{h\_total} = \sqrt[1/\alpha]{\sum_{i=1}^{n} I_{h,i}^{\alpha}}$$

The summation exponent α determined in this process is shown for selected harmonic currents in Figure 37 (5th to 7th and 11th to 13th order for six identical inverters) and in Figure 38 (17th 19th and 23rd to 25th order for 54 identical inverters), respectively. For odd-numbered harmonic currents not divisible by three (5th, 7th, 11th, 13th, 17th, 19th and 25th orders), the summation exponent over the entire power range is about 1. This means that, with respect to an ordinal number, the harmonic currents of all connected inverters superpose almost arithmetically.

For the even-numbered harmonic currents (divisible by three) e.g. of the 6th, 12th, 18th and 24th, summation exponent will be in the range between 1.2 and 2.3 over the entire power range, which is caused by cancelling effects. This effect is even more pronounced at higher harmonic orders. Due to different phase positions of the individual harmonic currents, a proportional compensation / cancellation occurs here within the vectorial addition (summation). Compared with a purely arithmetic addition of the amplitude values of the harmonic currents, the total harmonic current is therefore significantly lower.

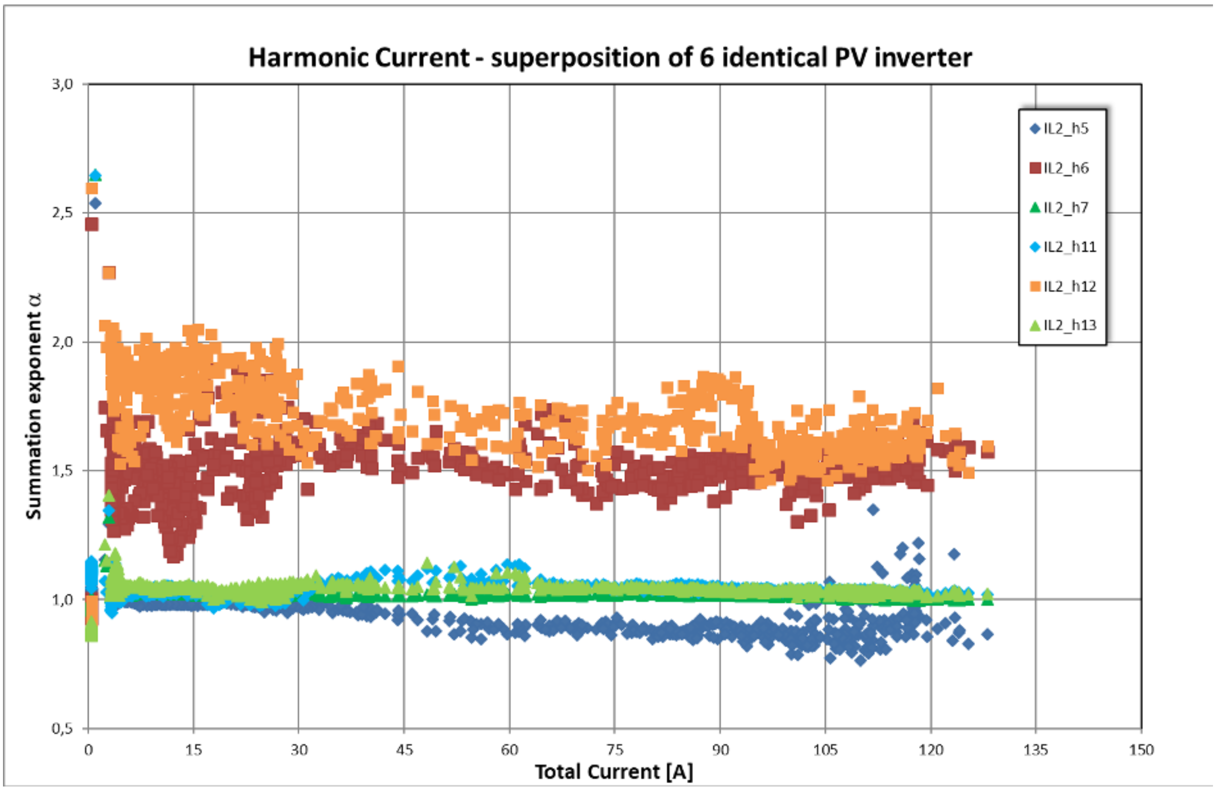



**Figure 37:** Harmonic current superposition within the PV plant: Harmonic current summation exponent $\alpha$ of six identical PV inverter as a function of the total current

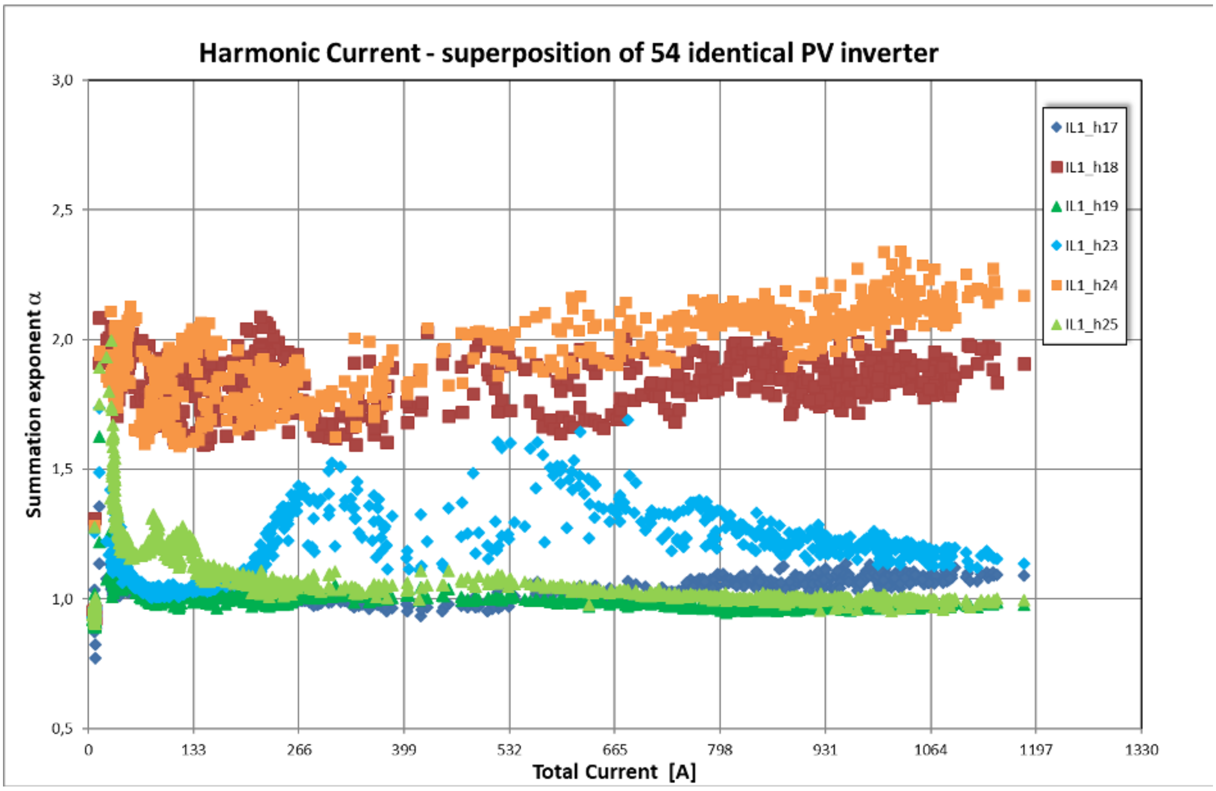



**Figure 38:** Harmonic current superposition within the PV plant: Harmonic current summation exponent $\alpha$ of 54 identical PV inverter as a function of the total current

## 4.11 PV inverter in hybrid (DC,AC) microgrids

Authors: G. Graditi, G. Adinolfi (ENEA)

**Objective:** PV inverter as DC side service provider in hybrid (DC, AC) microgrids: reliability evaluation as preliminary condition to foster PV inverters employment in energetic (DC, AC) communities
**Field area /laboratory test:** PV plants installed and emulated at South Italy latitudes \ENEA R.C. SGRE Lab
**Considered PV systems:** Residential 15kW PV plants and 41 PV inverters designed by ENEA R.C. SGRE Lab
**Applied inverter functions:** PV inverter as DC side ancillary service provider
**Main results:** PV inverter can be suitably controlled to provide DC side services but topological/ technological improvements are necessary in terms of power stage reliability.

International and national climate and energy agreements prescribe decarbonisation targets by deep RES penetration. In detail, the widespread diffusion of PV installations and their future increase will lead to stability problems due to the integration of these intermittent and variable sources in the existing AC network. The introduction and management of these energy sources could be carried out in a flexible and efficient manner in the context of hybrid (DC, AC) networks. They can represent promising solutions capable of combining the advantages of AC distribution systems with the concept of DC electricity distribution. Nowadays hybrid grids can represent a well-suited paradigm to energy communities and renewables clusters. They can operate in grid on and isolated conditions, however guaranteeing resources management.

These hybrid grids take advantages of different architectures based on involving both Medium Voltage (MV) and Low Voltage (LV) connections. Some feasible topologies for hybrid DC, AC power systems are reported in Figure 39.

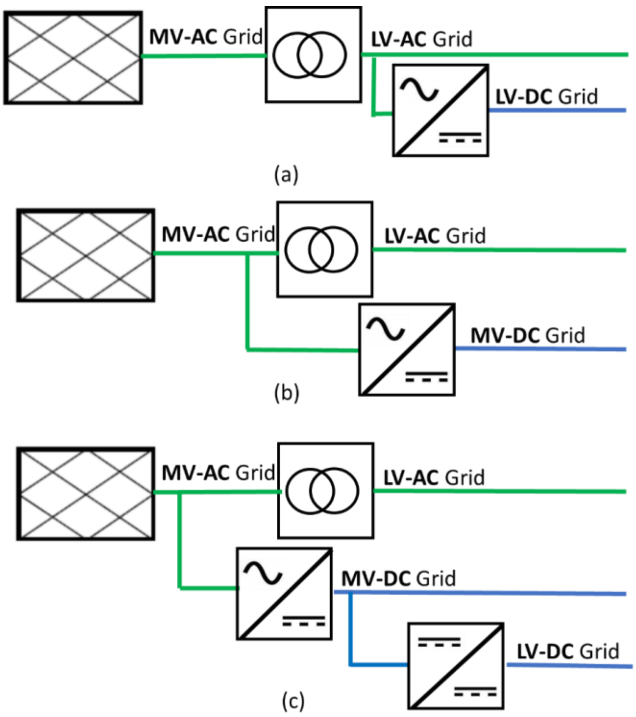



**Figure 39:** Hybrid DC/AC architectures: topological connections

The prototype realizations of hybrid (DC, AC) architectures have recently been investigated making possible to ascertain their characteristics and performance, focusing the attention on strengths and criticalities.

It is worth noting the presence of Interface Converter (IC) as front-end systems among the grid DC and the AC sides. In the considered energetic scenario with heavy PV introduction, PV inverters could constitute ICs able not only to carry out the DC/AC conversion, but also to assure suitable ancillary services to AC and DC grids. In this document, different services to the main AC grid are considered. In this paragraph, the attention is focused on the

PV inverter as DC side service provider. In fact, DC micro, minigrids and self-consumption clusters represent emerging energetic configuration. DC renewables, storage and recent DC loads (electric mobility, conditioners, and light systems) diffusion are favouring the DC grid paradigm. In this context, the PV inverter can operate not only for renewables power conversion but it can also be employed as DC storage, loads and electric vehicles (cars, bicycles, scooters, etc) schedulers and controllers. In detail, the PV inverter can manipulate local power flows in order to mitigate RES curtailment and dispatching actions managing different resources also favouring energy source/sink operation among near neighbour microgrids.

As shown in Figure 40 a novel family of PV inverters is necessary to implement the described paradigm. Digital technology is mature to develop these PV inverters control strategy but a preliminary aspect to be considered is PV inverters reliability. This Key Performance Indicator (KPI) can be defined as the PV inverter ability to supply power to the main AC grid and to DC side users in the desired quantity and in compliance with operating standards. In hybrid (DC, AC) grids, the PV inverter unreliability can invalidate not only the grid injection, but it can also avoid functional operations on the underlying DC side.

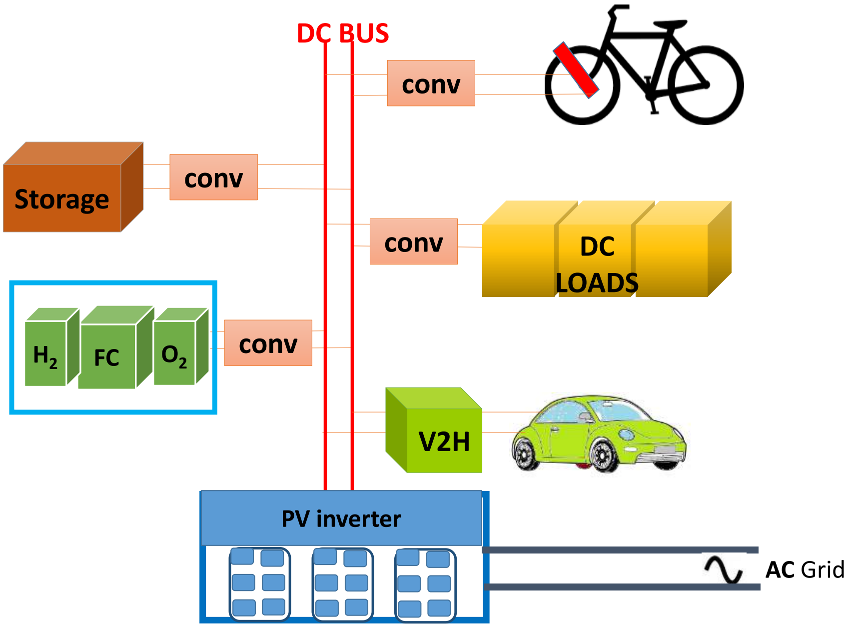



**Figure 40:** PV inverter in a Hybrid (DC, AC) context

It is worth understanding that such a delicate aspect must be considered and properly taken into account from the initial design steps.

Reliability analysis of an electricity system can be carried out using appropriate models and methods for the quantitative evaluation of specific performance indices [42]. Different physical, phenomenological and statistic methods are applied to reliability assessment achievement. In this case, the attention is focused on PV inverters acting as hybrid grid interfaces and their reliability is characterized by a probabilistic approach carried out by the Military Handbook 217F (MIL-HDBK-217F) prediction model [43], recognized as de facto standard in the application context. The mentioned prediction model provides failure rate formulas for different components on the base of specific failure mechanism and electro-thermal stresses. These formulas permit to calculate the reliability R(t) function, as reported in Eq.1.

$$R(t) = e^{-\lambda t} \tag{1}$$

where: $\lambda$ is the total failure rate for the adopted power stage topology
t is the mission time

According to MIL-HDBK-217F methodology, PV inverters reliability can be evaluated calculating devices failure rates, obtaining the total failure rate value for the considered converter topology, and applying the formula reported in Eq.1.

At ENEA Smart Grids and Energetic Networks (SGRE) lab, forty-one PV inverters for 15kW residential PV plants, based on commercial devices, are considered for a reliability assessment in hybrid (DC, AC) microgrids topologies as in Figure 39 (a). Actual South Italy irradiance and temperature graphs determined PV modules operating conditions.

PV reliability for 1,5,10 and 25 years mission time results are evaluated and reported in Figure 41.

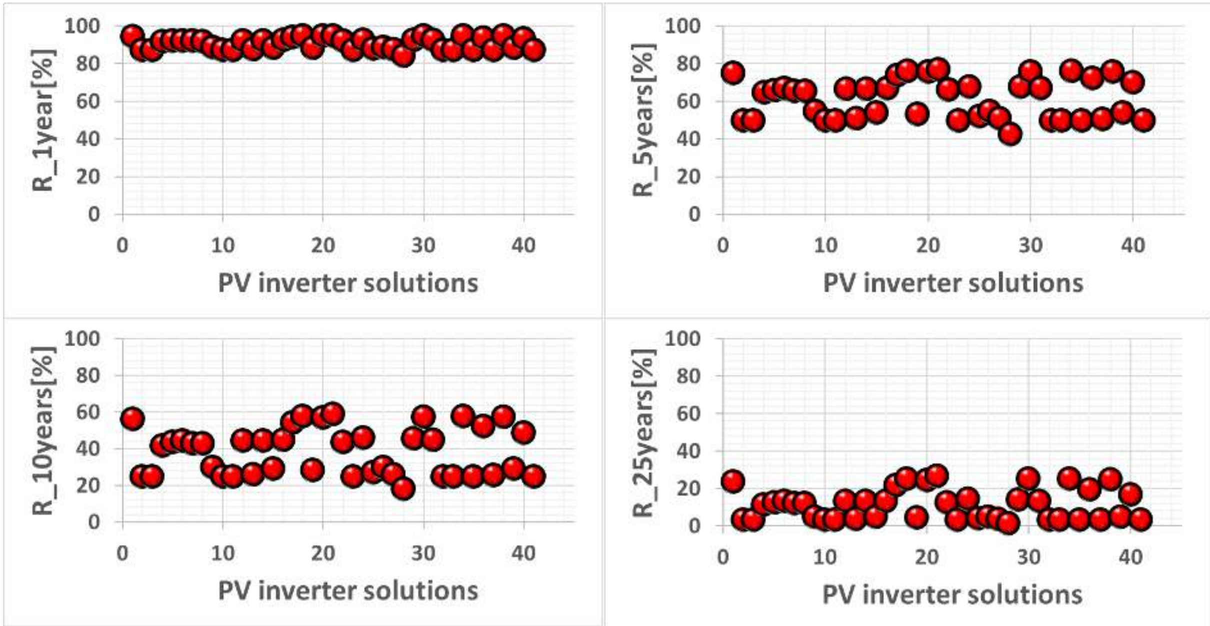



**Figure 41:** Inverters reliability trend for different mission time

The reported figures show the decreasing trend for the PV inverter reliability with a R (t) percentage of 50% for ten years mission time.

The PV inverter R(t) function deeply depends on switching devices characterizing this converter power stage and their ability to face thermal conditions ad stresses. The joined investigation of innovative DC/AC converters topologies based on switching technologies, more suitable to electro-thermal stressing modes than currently ones, and adequate control strategies could determine a new PV inverters generation able to assure successful performance in hybrid (DC, AC) configurations.

**Conclusion, lessons learned:**

- Innovative DC/AC converter solution to PV inverter providing DC side ancillary services
- PV inverter reliability improvement by novel switching technologies application
- SiC and GaN based DC/AC converters to Medium and Low Voltage hybrid grid configurations
- Redundant topologies for PV inverter reliability improvement

# 5 CONCLUSION AND OUTLOOK

This report aims to highlight the status and the potential of PV and PV hybrids as ancillary service providers. It provides a collection of laboratory and field experiences from different IEA PVPS countries and for different ancillary services. This final chapter summarizes the findings of the different international experiences and provides an outlook on PV systems and PV hybrids as an ancillary service provider.

## PV frequency control

„Frequency control is a set of control actions aimed at maintaining the system frequency at its nominal value" [2]. The frequency control is implemented in different stages, distinguished by different response times and durations, typically primary control, secondary control, and tertiary control. In this report, project and field-tests results from Germany concerning the capability of PV and Wind power plants to provide frequency control services for the German TSOs are highlighted.

**Frequency control services by Wind and PV plants in the project REWP - Selected project findings:**

- In the German ReWP project [18], probabilistic forecasts for individual parks were created and procedures for combining them into pool forecasts were developed. This demonstrated the advantages of pooling compared to a simple summation of the individual park reserve power offers.
- In the field test, it was shown that under the given German prequalification conditions, the dynamics of wind and PV power plants are sufficient to fulfill the condition for the provision of secondary frequency reserve.
- In addition, it is shown that the possible reserve power offer depends strongly on the security level and product length factors. For example, shorter tendering periods and shorter product time slices can support the participation of PV systems in these control reserve markets.

Furthermore, this report provides field experiences and lessons learned from a major system disturbance in Australia in 2018 and the distributed PV response behaviour.

**Distributed PV response to a major separation event and resulting frequency excursions in the Australian National Electricity Market, August 2018:**

- **Selected findings**: The report [16] found: "a clear aggregate response of the correct shape and approximate magnitude, suggesting that this designed control response is correctly implemented in some proportion of the PV inverters." It also found that the 2015 update of the previous 2005 standard (which did not have frequency equivalent response requirements) had a material impact on the aggregate response of inverters. However, approx. 15% of analyzed systems installed after October 2016 did not provide the requested frequency response behaviour, which has led to subsequent investigation and increased compliance monitoring.
- Selected report [16] recommendation:
    - The evaluation of technical inverter requirements (AS 4777) and inverter performance standards in cooperation with Standards Australia and the industry.
    - The establishment of a solution to obtain data on the performance of distributed PV systems and the development of necessary simulation models and tools to predict their response to system disturbances.

**Frequency control services by PV plants - Outlook:**

- PV systems are able to deliver all existing products of control reserve and to adjust their power output even faster than specifications for Frequency Containment Reserve (FCR) require. But today, PV systems are not involved in delivering control reserve the because market conditions and regulatory framework are not suitable. PV power plants must be given the opportunity to participate in all reserve markets (FCR, automatic Frequency

Restoration Service (aFRR), manual Frequency Restoration Service (mFRR)) under adequate framework conditions, by market design enhancement.

- Current frequency reserve market conditions hamper the introduction of PV systems due to regulation barriers, as in Germany, where direct PV integration is currently not included in the prequalification conditions. Furthermore, it is beneficial if gate closure times are close to real-time as well as shorter product slices in order to take advantage of more accurate intraday forecasts. ENTSO-E's initiatives such as the projects MARI ("Manually Activated Reserves Initiative" [44]) for a central mFRR platform and PICASSO ("Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation" [45]) in the case of aFRR will both introduce such short-term market conditions.
- Another aspect of smaller PV units (in the lower kW-range) is the higher relative expense of a secure IT connection if the same strict rules apply as for larger units. For example, since December 2019, German TSOs [46] allow small unit aggregation of up to 2 MW. This means that a serial interface can be at a central point instead of at each device where the individually installed power does not exceed 25 kW.
- The last highlight relates to the general complexity of handling smaller units including PV in a reserve market throughout the entire process from prequalification to settlement. Current processes are usually not designed to handle up to millions of participating assets in a cost-efficient manner. To mitigate this issue the Swiss TSO Swissgrid initiated the "Crowd Balancing Platform Equigy" together with the Dutch TSO TenneT and the Italian TSO Terna [47]. It is a permissioned blockchain-based platform that supports the interaction between the aggregators, the TSOs, and the DSOs as well as the original equipment manufacturers to register, accept and validate flexibility offers with standardized interfaces to the different parties involved. However, the platform is not designed for the actual offer fulfillment. As a result, the existing control mechanism of the aggregator is still required.
- Going forward, there is a clearly identified need for both large-scale and aggregated-distributed PV to provide additional system support and ancillary services where possible, with likely increasing value for systems to maintain 'headroom' to provide operating reserve, more accurate forecasting, frequency support, and potentially grid-forming capability [19].

## PV active power curtailment

PV power curtailment can be an effective measure to increase the PV grid hosting capacity and can support congestion management, voltage control, and power balancing at the transmission and distribution level. This report presents field test applications of two curtailment procedures of residential PV systems.

**Dynamic PV Power Curtailment – selected project findings:**

- Dynamic PV power curtailment works and is an economic measure to increase the PV hosting capacity of a grid. However, the precision of the controller is limited in the tested device. Therefore, the application of an additional safety margin is recommended to secure compliance with a defined feed-in limitation.

**Remote curtailment of residential PV systems via Smart Meter Gateway – selected project findings:**

- With Digitalization and the introduction of Smart Grids, effective and economic remote curtailment will also become available for residential PV systems. The C/sells field test demonstrated the use of the Smart Meter Infrastructure (Smart Meter Gateway, SMGW-Admin, CLS-Gateway, and CLS-Management) for secured, bidirectional communication between PV inverters and a distribution control center. With the utilization of the IEC 61850 data model, the automatic integration of massive residential PV systems into the distribution control center became possible and reduces the integration effort for RES.
- In addition, a digital grid connection point has been introduced which integrates Energy Management Systems (EMS, HEMS) of buildings in grid power control. Instead of active curtailment, the grid operator acts like a traffic control system supervisor and communicates load and feed-in power limits. The EMS independently can make

its decision achieving the power limits by the different flexible loads, storage devices or renewable energy systems, which are placed behind the digital grid connection point.

**PV power curtailment - Outlook:**

- Curtailment of PV power will be crucial for cost-effective grid integration of PV power. However, it is not clear yet, which method of PV power curtailment is most suitable. Therefore, use cases for PV power curtailment should be collected.
- Curtailed PV systems could theoretically enable various new services, e.g. symmetrical primary control reserves or operating reserves to support forecast uncertainty. However, it is not clear yet, if and how this could be implemented.
- The further development and implementation of Smart grid concepts are essential to harness the large potential of distributed and residential PV as an ancillary service provider.
- Smart grids with highly distributed penetration require a high level of standardization and automation. Easy connect and manage of a large number of distributed resources, i.e. registration.
- The photovoltaic community, especially the inverter manufacturer, project developer and monitoring companies have to adapt its communication concepts and data models to these upcoming Smart Grids Standards.
- Introducing standardization to millions of DER, cyber security aspects have to be taken into account to ensure a safe grid operation with high penetration of decentralized PV Systems.
- Although some countries compensate the energy losses due to curtailment today, in the future curtailment will become a regular situation without compensation, when the actual photovoltaic feed-in power exceeds the residual load.

## PV voltage support / reactive power control

A management summary on local reactive power control by PV inverters is provided in a previous publication by the IEA PVPS Task 14 [3]. Therefore, PV systems with local reactive power control can support voltage regulation and can further increase the PV hosting capacity at the distribution level. Further voltage support services by distributed PV systems, such as reactive power compensation for commercial consumers or reactive power provision for upstream transmission grid operators are addressed in this report.

**PV local reactive power compensation – Selected project findings:**

- Reactive power compensation is an issue that mainly impacts industrial sites and medium and high-voltage power transmission. In these industries, the reactive power induced by the equipment is generally regulated by means of capacitor banks. Due to their design and as shown in this study, photovoltaic inverters can provide a similar result to capacitor banks while providing additional functionalities:
    - Larger operating range: Inverters can compensate for any continuous value within their operating range.
    - Fixed or dynamic compensation.
    - Additional service: Some inverters can be used independently of the solar production, for example at night, to provide ancillary services (potential additional income).

**Remote PV reactive power provision at the transmission-distribution interface – Selected project findings**

- The successful field test in the SysDL2.0 project showed the control of up to 40 MVAr from distributed RES at the transmission-distribution interface.
- PV and Wind DER could realize the central Q set points mainly with good accuracy, but partly with different delay and gradient limitations.

- Ancillary services from distribution grids house great potential to compensate generation in the transmission grid.

**PV voltage / reactive power control – Outlook:**

The demand for reactive power compensation and flexible reactive power provision will further increase in many power systems in the upcoming years. Reasons are, for example, grid reinforcements and grid expansions, increased power transfers, and a changing demand and supply structure. Large conventional power plants, such as coal and nuclear power plants, are still a major source for reactive power provision in most AC transmission grids. However, with the phaseout of coal and partly nuclear power plants in several countries in the coming years, additional controllable sources of reactive power have to be implemented and applied. An important development here is coordinated reactive power management at both transmission and distribution level, which utilizes the reactive power capability of RES, conventional generators, compensators, and further grid assets in a stable, secure, and efficient manner.

- New regulatory frameworks should encourage the application of standard (according to current grid code requirements) and advanced reactive power capabilities (i.e. reactive power provision with no active power generation) of PV systems and other RES by the grid operator, wherever meaningful.
- Reactive power provision by PV systems can lead to additional costs for the plant owners. Further discussions and clarification concerning mandatory and optional reactive power services by PV systems and other RES are needed. This can require the (further) development of appropriate procurement procedures for reactive power and voltage support services by the grid operators. For example, according to EU regulations [48], transmission and distribution grid operators should cover their reactive power demands starting from the year 2021 through a transparent, non-discriminatory, and market-based procedure, as long as the national regulatory authority has not granted an exception [49].
- Besides the local reactive control of PV systems, central reactive power dispatch by the grid operator becomes increasingly important for coordinated reactive power management. This requires an appropriate ICT infrastructure and data model application, such as CIM CGMES, at both the transmission and the distribution level.
- For coordinated reactive power management and market-based procurement procedures of reactive power; appropriate forecasts of reactive power demand and reactive power flexibility potential at relevant grid nodes, i.e. transmission-distribution interface, are also needed.

## PV hybrids with grid-forming functionalities

A grid-forming inverter describes “an inverter having a control approach with the capability to control the terminal voltage directly and to form the grid voltage purely by inverters under consideration of necessary reserve and storage capacity” [4]. The report provides examples for the successful application of grid-forming inverters in insular power systems and microgrid applications.

**PV storage hybrid system for 100% solar power on the remote island of St. Eustatius- project findings**

- The St. Eustatius PV hybrid power plant, with its conventional and inverter-based generation, combined with battery storage and a parallel operation of grid forming and grid supporting control, proves that a stable operation of power grids is feasible without conventional must-run-units and their inertia and fault current contribution. Even in emergency situations caused by grid faults or power system splits, with a huge power imbalance between generation and demand and combined with a stepwise inertia decline in the remaining areas, voltage and frequency deviation and restoration time are superior compared to conventional mechanisms in today’s European power grids.

**One hour with 100% renewable power - islanding operation test of the German community of Bordesholm –project findings:**

- Pioneering hybrid power system projects on a Megawatt-scale such as in the German village Bordesholm or on the remote island of St. Eustatius prove that a stable and secure grid operation with 100% inverter penetration and completely without conventional must-run-units is feasible also in public electricity grids. To encourage voltage-controlled grid forming inverter operation in public grids, grid code modifications and the enhancement of the economic framework are very important in the upcoming years.

**PV hybrids in the island power system of El Hierro - Selected project findings:**

- The conclusions of this analysis were useful for defining the characteristics needed in a near-future bidding process in order to supply a PV-battery system to Gorona del Viento S.A. for increasing the share of renewable energies in El Hierro. The main findings were the following:
    - The control system for the PV and batteries' inverters must be integrated into the same platform, guaranteeing services in island mode, short circuit power and power-frequency mode.
    - The PV battery system must be compatible and integrated into the SCADA of the hydro-wind power system, and ready to offer active and reactive power to the grid.
    - The system should be tested previously to any purchase in order to check that it will be supportive of the frequency ranges included in the grid codes for insular systems in Spain.
    - The equipment to be purchased must be previously tested for high levels of salinity, as the power plant is located in a coastal area.

**PV hybrids with grid-forming functionalities - Outlook:**

In addition, the existing grid codes are usually designed for current-controlled, grid supporting inverters. The advantageous behavior of grid-forming inverters in public grids is currently inhibited by most of the technical rules for grid-connected operation. Requirement specification for grid forming inverters is needed regarding the

- evidence of grid-forming behavior,
- fault-ride-through behavior,
- behavior at operational limits of the inverters,
- prevention of and behavior at unintended islanding,
- characterization of inverter-based inertia,
- common test procedure and quality criteria that are harmonized on an international level.

## PV inverter in hybrid DC/AC power systems

The need for new ancillary and grid services in electric power systems will further emerge with the progress of the energy transition in many countries. For example, the introduction and management of a high share of variable distributed renewable energy sources could be carried out flexibly and efficiently in the context of hybrid (DC, AC) networks. The report provides laboratory experiences from Italy concerning PV inverters in hybrid DC/AC power systems.

**PV inverters in hybrid DC/AC microgrids - Selected project findings:**

PV inverters can be suitably controlled to provide DC side services but topological/ technological improvements are necessary in terms of power stage reliability.

- Innovative DC/AC converter solution to PV inverter providing DC side ancillary services
- PV inverter reliability improvement by novel switching technologies application
- SiC and GaN based DC/AC converters to Medium and Low Voltage hybrid grid configurations
- Redundant topologies for PV inverter reliability improvement

**PV inverter in hybrid DC/AC power systems- Outlook**

PV inverters application in hybrid grids represents practicable solutions but their reliability performances evaluation and improvement constitute challenging tasks in terms of:

- standardization of a reliability prediction model to evaluate PV inverters reliability also considering novel switching technologies devices
- inverters operating data acquisition and processing
- the commercial availability of inverters fulfilling the voltage (DC side) and power requirements of the hybrid grids

In addition, further studies are mandatory to analyze Wide Band Gap (WBG) and novel switching technologies failure mechanisms and modes to the aim of avoiding/mitigating them.

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