IEA INTERNATIONAL ENERGY AGENCY

High Penetration of PV in Local Distribution Grids:

Subtask 2: Case-Study Collection

PHOTOVOLTAIC
POWER SYSTEMS
PROGRAMME

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Foreword

The massive deployment of grid-connected PV in recent years has brought PV penetration in the electricity grids to levels where the conventional fit-and-forget approach to interconnecting PV reaches its limits. In many cases, constraints and limitations of existing electricity infrastructure already have evolved to one of the key barriers delaying or impeding the realisation of PV projects.

While until recently grid issues associated with increased PV Penetration levels have been an issue in just a few local markets mainly in Europe, it has since then become a truly global issue – attracting global interest and attendance. In many cases PV has already become a game-changer in the way utilities, transmission as well as distribution system operators plan and operate power system infrastructure. Last but not least the grid integration of High Penetration PV has been identified as key prerequisite for the future development of the world-wide solar industry.

It is clear that resolving these global challenges requires the broad collaboration of experts from different stakeholders involved and the access to global information on experiences and best practises. Consequently, the Photovoltaic Power Systems Programme of the International Energy Agency (IEA-PVPS) has put up grid integration of on top of its research agenda, following its strategic mission "to enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems".

Coordinated by Task 14 "High Penetration PV in Electricity Grids" a worldwide group of experts has been working together exchanging expertise and developing innovative solutions addressing technical as well as non-technical challenges for the advanced integration of PV. From its beginning Task 14 has focused on working together with utilities, electricity industry, and leading research to develop the technologies and methods to enable the widespread deployment of distributed PV into the electricity system.

Task 14 addresses integration challenges and technologies on two main levels of the power system, local distribution grids and the overall power transmission system.

The present report specifically covers aspects related to distribution integration, presenting a worldwide selection of best-practice case studies and the latest findings from the working period from 2010 to 2013 within the IEA Task 14 Subtask 2. It enables the reader to deeply understand the fundamental characteristics of the national distribution grids and associated technical issues that are related to high PV penetration in the local power system. including current technical and regulatory interconnection requirements.

Highlighting technically effective and economically efficient solutions for improved distribution grid integration of high levels of PV penetration, the report supports experts from utilities and industry as well as responsible authorities in their business to design, manage and effectively operate power distribution systems with High Penetration PV.

Roland Bründlinger and Christoph Mayr, Task 14 Operating Agents.

Preface

The International Energy Agency (IEA), founded in November 1974, is an autonomous body within the framework of the Organisation for Economic Co-operation and Development (OECD) that carries out a comprehensive program of energy cooperation among its 23 member countries. The European Commission also participates in the work of the agency.

The IEA Photovoltaic Power Systems Programme (IEA-PVPS) is one of the collaborative research-and-development agreements established within the IEA, and since 1993 its participants have been conducting a variety of joint projects in the applications of photovoltaic (PV) conversion of solar energy into electricity.

The mission of the IEA-PVPS program is to enhance the international collaborative efforts that facilitate the role of PV solar energy as a cornerstone in the transition to sustainable energy systems by

1. Ensuring sustainable PV deployment,
2. Improving PV performance and reliability, and
3. Assisting in the design of new market structures and regulations that will be suitable for the widespread adoption of unsubsidized PV.

The overall program is headed by an executive committee composed of one representative from each participating country, whereas the management of individual research projects (tasks) is the responsibility of the operating agents.

The overall goal of the IEA-PVPS Task 14, "High Penetration of PV Systems in Electricity Grids," is to promote the use of grid-connected PV as an important source in electric power systems at the higher penetration levels that may require additional efforts to integrate dispersed generators. The aim of these efforts is to reduce the technical barriers to achieving high penetration levels of distributed renewable systems.

The current members of the IEA-PVPS Task 14 include Australia, Belgium, Canada, Switzerland, China, Germany, Denmark, Spain, Israel, Italy, Japan, Portugal, Sweden, and the United States of America.

The IEA-PVPS Task 14 is organized in subtasks. Figure 1 shows the organizational structure of this international collaboration.

Fig. 1: Organizational structure of the IEA-PVPS Task 14

This report presents the outcome of the IEA-PVPS Task 14 Subtask 2, "High penetration PV in local distribution grids," from the 2010 to 2013 working period. Selected case studies from 11 participating countries dealing with high PV penetration in distribution grids and national best-practice solutions for technically and economically improved distribution grid integration of PV are presented. The report complements the Subtask 2 management summary, which can be found in the following reference:

Management Summary
Transition from Uni-Directional to Bi-Directional Distribution Grids—Recommendations Based on Global Experience. Management Summary of IEA Task 14 Subtask 2

Case Study Collection
High Penetrations of PV in Local Distribution Grids—IEA-PVPS Task 14: "High-Penetration of PV Systems in Electricity Grids." Subtask 2: Case Study Collection

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1 Introduction

This report presents the International Energy Agency Photovoltaic Power Systems Programme (IEA-PVPS) Task 14 Subtask 2 case study collection on high penetrations of photovoltaics (PV) in local distribution grids. National experts from industries and research in 11 countries present the current status of PV penetration as well as the latest findings from their home countries regarding the technically and economically improved distribution grid integration of PV. A management summary of the case study collection can be found in:

Transition from Uni-Directional to Bi-Directional Distribution Grids—Recommendations Based on Global Experience. Management Summary of IEA Task 14 Subtask 2.

1.1 Motivation

When the IEA Task 14 was founded in 2010, annual PV installation rates were at their maximums in many countries throughout Europe. The vast and rapid PV deployment led—and still leads to—many technical and economic challenges on distribution systems because the behavior of some distribution grids changes from one of consumption to one of supply. Local distribution system operators were forced to instantaneously react to the locally growing PV penetration rates with revised grid planning and grid operation processes that, until then, had been tailored to serve consumption grids only and were well established during the past decades. In some countries, these processes were also fueled by a strict regulatory framework that limited the technical possibilities for distribution system operators to cope with the rising installation rates in a technically effective and economically efficient manner (e.g., the primary grid access for renewable energies as defined by the German Renewable Energy Sources Act). As a result, many different research projects were initiated on national levels that aimed to review grid planning and grid operation processes to improve the technical as well as economic integration of PV in distribution grids.

The motivation of IEA Task 14 Subtask 2 is to bring national experts on distribution grid integration of PV together to share and discuss the latest research results and national developments dealing with high PV penetrations in local distribution grids. This international collaboration

- Opens access to different national best-practice solutions for technically and economically improved PV grid integration (**Participation**),
- Opens access to the latest market developments and changes within the respective national regulatory frameworks of the participating countries (**Information**); and
- Provides a platform for the dissemination of solutions and research results (**Dissemination**).

It is without doubt that an improved international collaboration has the potential to effectively utilize synergies that already exist between the research programs in different countries. In turn, the presented results and findings can be used by other countries to more efficiently align their national research programs based on outcomes that have already been gained elsewhere in the world.

1.2 Goal of Study

The goal of this study is to provide the reader with the best-practice case studies and the latest findings that were discussed during the 2010 to 2013 working period within the IEA Task 14 Subtask 2. The information provided highlights technically effective and economically efficient solutions for improved distribution grid integrations of high levels of PV penetration.

By reading this report, the reader should be able to understand the basic structures of the respective national distribution grids and the associated technical and economic issues that are related to high local PV penetration scenarios. This encompasses current technical and regulatory interconnection requirements for PV systems, the most urgent technical issues in high-level PV penetration scenarios, and upcoming regulatory changes in the participating countries.

Moreover, best-practice case studies show how control capabilities of modern PV inverters (e.g., volt/Var provision) can be properly used within the context of grid planning and operation to increase the hosting capacity of distribution grids for additional generation capacity. In addition, cost-benefit analyses highlight the savings potential that can be achieved by actively applying inverter control capabilities within the context of revised grid operations.

1.3 Report Structure

This report is structured by national reports of the IEA Task 14 Subtask 2 member countries in alphabetical order. Each national report consists of the following subsections:

- The National Distribution Grid Structure
- Interconnection of Photovoltaic Systems: Technical and Regulatory Framework
- Required Control Capabilities for Photovoltaic Inverters
- Case Studies for High PV Penetration Scenarios
- Upcoming Regulatory Changes and Future Challenges for High PV Penetration

A management summary of the overall IEA Task 14 Subtask 2 activities can be found in:

Transition from Uni-Directional to Bi-Directional Distribution Grids—Recommendations Based on Global Experience. Management Summary of IEA Task 14 Subtask 2.

The authors of the respective national reports are solely responsible for their content.

2 High Penetrations of Photovoltaic Systems in Distribution Grids—Country-Specific Analysis

Australia

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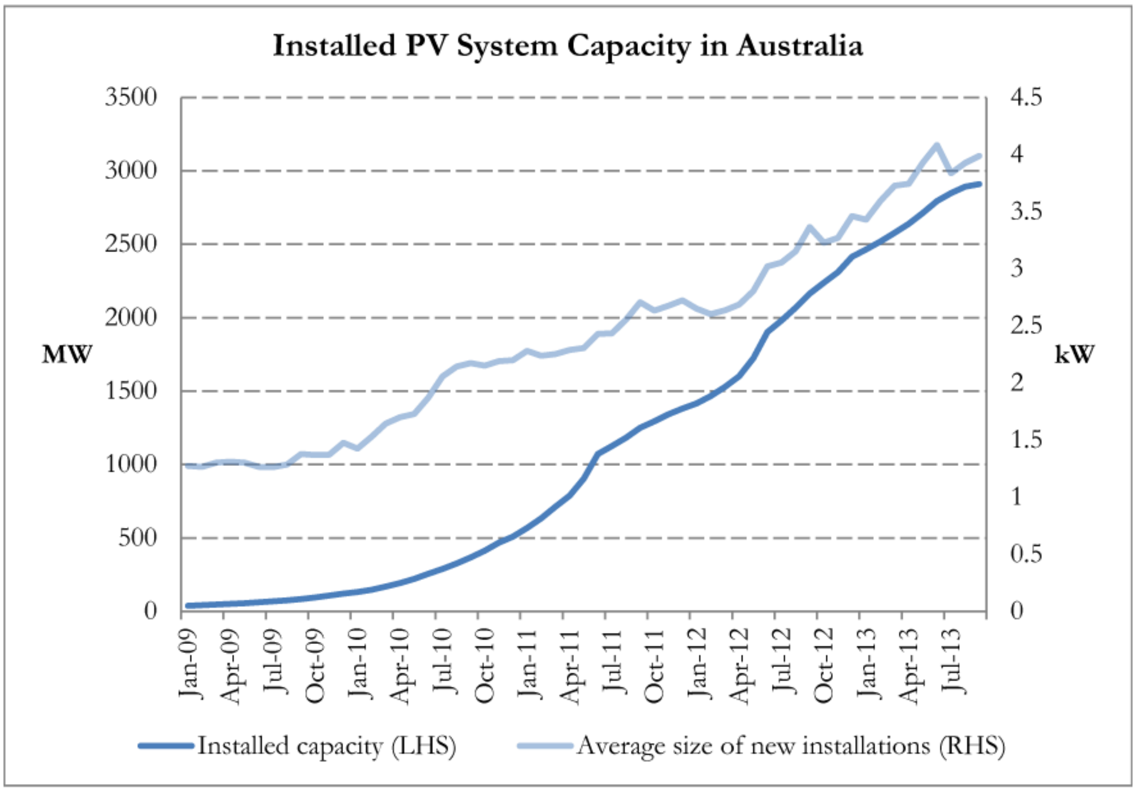
Table 1: Summary of Australian Statistics for Solar PV Electricity Generation and Demand

Statistic	Value	Year
Installed PV capacity	2.9 GW	2013 [1]
Peak load – National Electricity Market (NEM)	31.1 GW	2011–12 [2]
Peak load – South-West Interconnected System (SWIS)	3.9 GW	2011–12 [3]
Total generation capacity – NEM	48.3 GW	2012 [2]
Total generation capacity – SWIS	6 GW	2012–13 [3]
Estimated total energy generated by PV	3930 GWh	2013 [1]
Share of PV on total electricity consumption	1.9%	2013 [1, 3–5]
Average size of PV system	2.6 kW	2013 [1]



Source: Clean Energy Regulator, Renewable Energy Target database

Figure 1: Cumulative installed PV capacity in Australia (status 10/2013)

The National Distribution Grid Structure

More than 8 million customers [6] (approximately 90% of the total electricity customers in Australia) are serviced by the Australian National Electricity Market (NEM). This interconnected system includes the eastern states of Australia (Queensland, New South Wales, and Victoria) as well as South Australia, Tasmania, and the Australian Capital Territory. However, there are large, sparsely populated areas within these states and territories that are not grid-connected. Remote towns often have a mini-grid system, typically powered by gensets fueled by diesel or, if available, gas. Spanning a distance of approximately 5,000 km, the NEM is arguably the longest interconnected power system in the world [6]. Smaller, autonomous networks operate in the other states and territories, specifically in Western Australia (the South Western Interconnected System, or SWIS) and the Northern Territory (Darwin-Katherine Interconnected System, or DKIS).

In the NEM, the *transmission* network operates at voltages of 220 kV and above, whereas the *distribution* network operates at voltages of 132 kV and below (see Table 2 below) [7]. In Western Australia and the Northern Territory, the term "distribution network" applies to networks that transport electricity at voltages of less than 66 kV [8, 9].

Table 2: Australian Categorization of Nominal Voltages

Electricity Supply Chain	Nominal Voltages (kV)
Transmission	500, 330, 275, 220
Distribution	132, 110, 66, 44, 33, 22, 11 and below

Using these definitions, there are slightly more than 765,000 km of distribution lines and cables in the major Australian electricity systems. Of this total, 14% are underground, 28% are classified as low voltage (640 V and below), and 22% are single-wire earth return (SWER) [10]1. Data does not exist for the distribution of PV systems across different voltage levels; however, almost all solar PV capacity in Australia is composed of systems of less than 10 kW connected to the low-voltage (LV) distribution network (see Figure 2). This means that the penetration of PV in relation to the proportion of customers who have PV systems is high compared to most other countries. For example, the percentage of customers in the state of South Australia who have a PV system is approaching 20% (Table 3).

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[1] SWER lines are low-cost, single-phase distribution lines that utilize a single wire and an earth-return path (no neutral). SWER lines are commonly used in remote, sparsely populated parts of Australia, notably Queensland, and typically operate at voltages of 12.7 kV or 19.1 kV.

Table 3: Small-Scale PV Generation (Less Than 100 kW) in Australia (status: 11/2013).

State or Territory	Number of PV Installations	Installed Capacity (MW)	Customers with PV (%)
Australian Capital Territory	13,426	37	7.9%
New South Wales	248,085	613	6.5%
Northern Territory	2,664	10	3.1%
Queensland	353,622	983	17.6%
South Australia	154,194	438	18.7%
Tasmania	17,177	51	6.2%
Victoria	196,478	509	7.5%
Western Australia	147,185	335	13.1%
TOTAL	1,132,860	2,976	-

Source: Clean Energy Regulator (status 4/11/2013); Australian Energy Regulator 2012

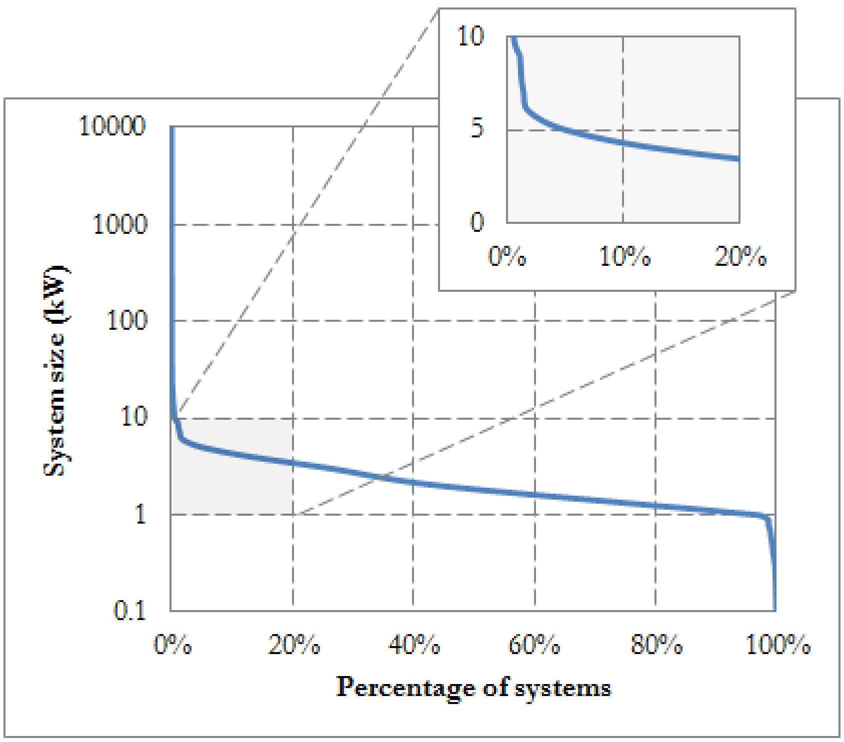

Figure 2: Cumulative distribution curve of PV systems by system size

Table 4 contains statistics on the distribution network service providers (DNSPs) in Australia [2].

Table 4: Statistics on Australian DNSPs

State	Company	Ownership	Number of Customers	Km Line	RAB (2010 $m)*	Maximum Demand 2010–11 (MW)	Customer Density (Per km Line)
ACT	ActewAGL	50/50 Government/private	168,937	4,922	635	701	34.3
NSW	AusGrid	Government	1,619,988	49,781	8,965	5,812	32.5
NSW	Endeavour	Government	877,340	34,172	3,925	4,069	25.7
NSW	Essential Energy	Government	1,301,626	190,531	4,595	2,292	6.8
QLD	Energex	Government	1,316,295	53,928	8,120	4,875	24.4
QLD	Ergon	Government	689,277	160,998	7,380	2,429	4.3
TAS	Aurora	Government	275,536	25,844	1,410	1,760	10.7
SA	SA Power Networks	Private	825,218	87,226	2,860	1,798	9.5
VIC	Citipower	Private	311,590	7,406	1,315	1,453	42.1
VIC	Jemena	Private	314,734	6,043	770	1,008	52.1
VIC	SPAusNet	Private	637,810	48,841	2,120	1,798	13.1
VIC	Powercor	Private	723,094	84,791	2,260	2,351	8.5
VIC	United Energy	Private	641,130	12,875	1,410	1,962	49.8

It is notable that some of the DNSPs have particularly low customer densities, with the lowest having an average customer density of only 4.3 customers per km of line (see Figure 3 for comparison). In rural areas, it is not uncommon for customers to be serviced by long SWER feeders.

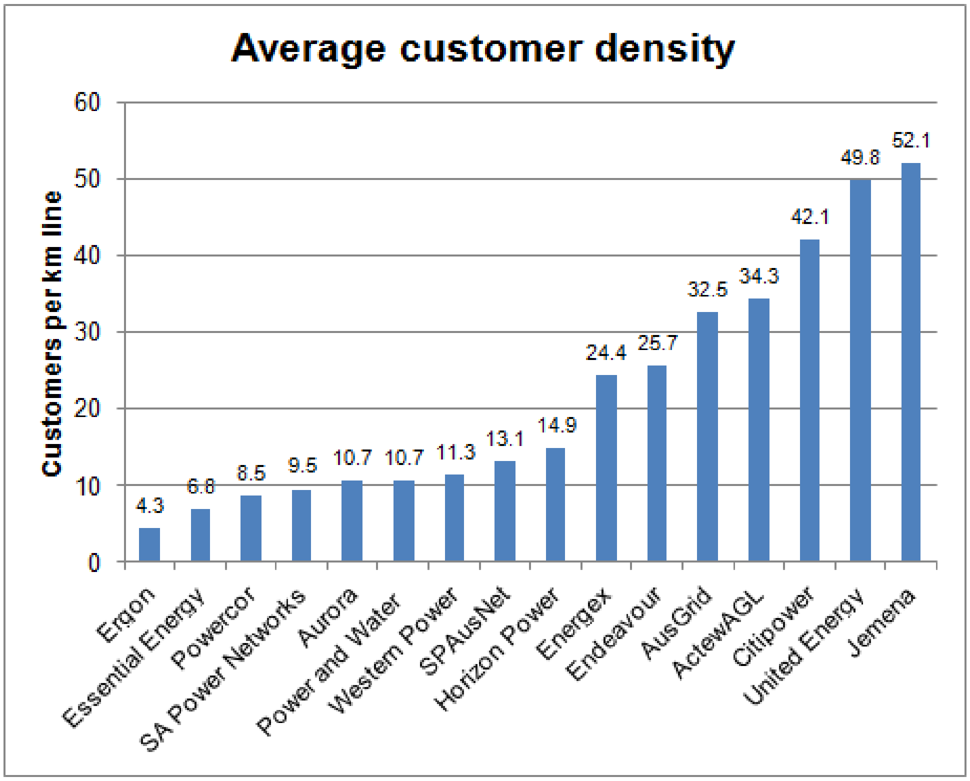

Figure 3: Average customer density of Australian DNSPs

Installed PV generation varies significantly by DNSP region according to the state-based PV policy support measures that are or were in place, the quality of the solar resource, and demographics (particularly housing density). Although PV is concentrated in the major capital cities of each state, significant deployment has also been seen in regional and rural areas where there are predominantly stand-alone housing stocks and often excellent solar resources (see Figure 4 below[2]).

[2] For this figure, "eligible dwellings" are defined as separate houses, semi-detached houses, caravans, cabins, and improvised homes that may or may not be permanently occupied. It is sourced from the Australian Solar Portal (forthcoming 2013) that uses data from the Australian Bureau of Statistics and the Clean Energy Regulator.

Particular distribution network hot spots for high PV penetrations have emerged driven by a combination of factors including the housing stock, solar resource, local industry capabilities, local government initiatives, and income levels. A number of isolated remote grids have also seen significant household-driven PV system deployment, such as the towns of Carnarvon and Alice Springs (case studies on these localities are presented in Section 0).

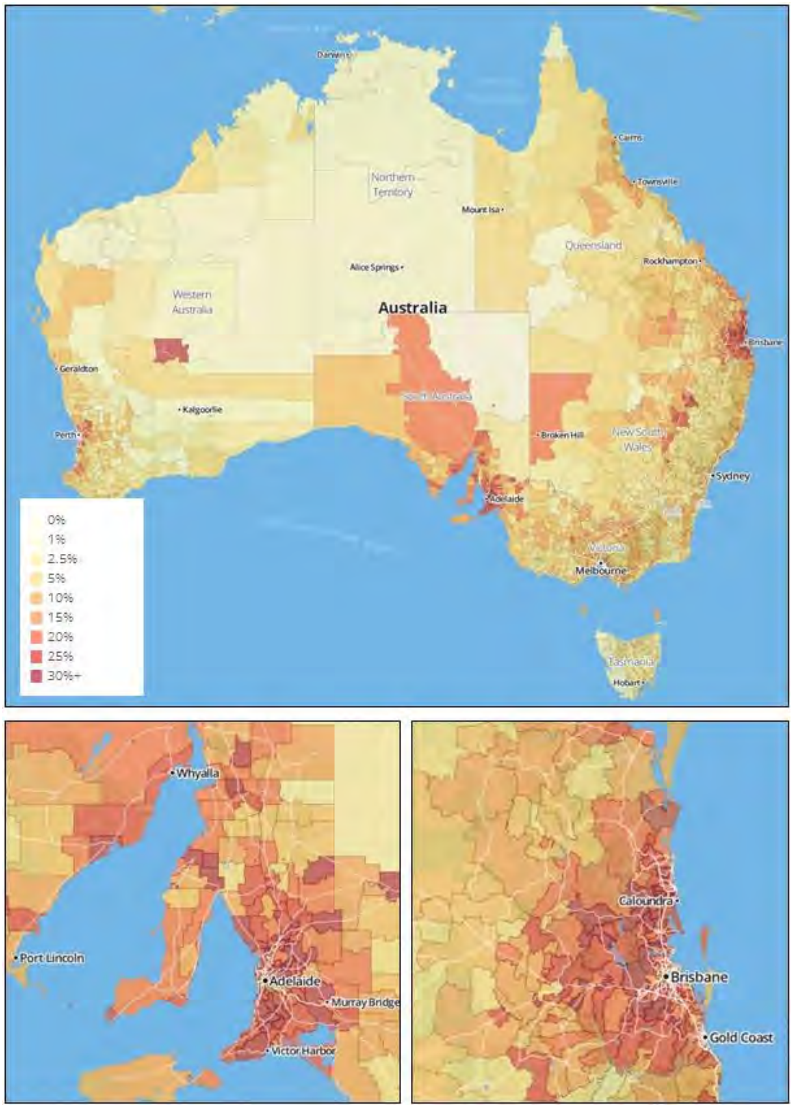

Figure 4: Percentage of eligible dwellings per post code with solar PV systems (status 03/2013)

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Regulatory Framework

The national regulator for network access and pricing is the Australian Energy Regulator (AER), which has jurisdiction over all the NEM regions. Individual regulators perform the functions of the AER in the states outside of the NEM—the Northern Territory and Western Australia. State-based regulators perform functions relating to the licensing and compliance of DNSPs.

The AER enforces the National Electricity Rules (NER). Section 5 of the NER "provides the framework for connection to the transmission network or a distribution network and access to the national grid" [11]. However, the provisions outlined in this section are primarily applicable to the connection of utility-scale generators that intend to operate in the wholesale market. At present, only a handful of PV systems in Australia fall within this category, and the significant majority of existing PV connections are for residential customers. For these distributed PV systems, state-based regulations supplement the NER and set the requirements for PV system interconnection.[3]

The vast majority of existing Australian PV customers were connected under various state-based, feed-in tariff arrangements that oblige utilities to connect eligible PV systems. However, almost all of these feed-in tariffs have been wound back. For new PV customers, state-based regulators—of which there are eight in total—have differing requirements regarding the obligation of DNSPs to connect PV systems. In the Australian Capital Territory (ACT), the distributor must connect a renewable energy generator of up to 200 kW to the distribution network [12]. In New South Wales, a generator must be connected provided that "it complies with relevant safety, technical and metering requirements" [13]. Three other jurisdictions, either explicitly or implicitly, allow DNSPs to determine whether or not PV systems are allowed to connect [14–16].

The Victorian Electricity Distribution Code specifies that if an embedded generator seeks connection to the distribution network, the distributor and the embedded generator must negotiate "in good faith" [17]. In Tasmania and South Australia, the regulators take a more active role, requiring that the standard connection agreement that the DNSPs offer to customers be approved by the regulatory body [18, 19]. In practice, and despite the variation in regulatory policy among jurisdictions in Australia, most DNSPs specify a threshold system capacity size under which minimal administrative requirements and set fees are applied to prospective solar PV customers (see "Technical Framework").

In terms of costs associated with grid interconnection, it is typical for the customer to pay for the meter, if this needs to be upgraded. In the Northern Territory, the customer must pay for a new gross meter [20]; whereas in the ACT, the DNSP is legislatively allowed to pass on additional metering costs [12]. In South Australia, the DNSP is allowed to charge for connection and network extension if the charge has been calculated "as an excluded service charge under the Electricity Distribution Price Determination" [19]. However, the

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[3] A new subsection, Section 5A, of the NER contains provisions for interconnection for retail customers, including embedded generators. See "Upcoming Regulatory ."

South Australian DNSP is not allowed to charge for any augmentation required as a result of the connection.

The AER specifies network tariffs that can be charged by each DNSP in three-year price determinations with annual revisions. These determinations are made on the basis of an assessment of proposals submitted by DNSPs that operate in the NEM. In 2009, a DNSP from New South Wales applied for permission to pass through administrative and compliance costs associated with the connection of PV customers [21]. This request was denied, and since this time no other similar requests have been made to the AER.

Medium-sized PV systems (from approximately 5 kW or 10 kW to 100 kW) have not been eligible for feed-in tariffs in most jurisdictions in Australia, and larger system connections must be individually negotiated with the DNSP. Fees are generally charged for processing the application. Some DNSPs have a standard fee structure, whereas others price the processing of applications individually [22]. Approval to connect is generally subject to a network impact assessment, with additional associated fees and an uncertain time frame (four to six weeks is not uncommon). The network impact assessment generally includes both load-flow (static power flow) and protection studies carried out by the DNSP at the expense of the PV customer. On the basis of the assessment, DNSPs may restrict export from the PV system, offer the PV customer an alternative point of connection, or require the PV customer to pay for network extension or augmentation.

The extent to which DNSPs can pass on any deep augmentation costs (network costs associated with the connection that lie beyond the immediate network connection itself) varies by jurisdiction. In Victoria, for instance, deep augmentation costs may not be passed on, where shallow augmentation is defined as augmentation up to and including the first transformer upstream from the generator [23]. DNSPs may also require additional protection (above what is required by AS4777, the Australian standard for grid connection of energy systems via inverters) and monitoring and/or control equipment and associated systems. The size threshold above which systems are not automatically connected, the process and timeline of assessment, and the fees differ by DNSP, and there is currently limited transparency about the process or fees that may apply in many cases. In addition, information about network capacity and existing loads in different parts of the distribution network is not generally available in the public domain. A number of DNSPs are currently preparing guidelines for the connection of medium-sized systems that will increase transparency and certainty and streamline the connection process. A change to the National Electricity Rules to increase the availability of distribution network data, including zone-substation load data, is also currently under consideration.

AS4777 standards do not apply to large PV systems (>100 kW). Large systems are invariably subject to individually negotiated connection agreements and usually require more detailed technical studies than medium-sized systems. Systems up to 30 MW are not required to formally participate in NEM scheduling processes, including making wholesale market offers. In such cases, there appears to be negative load from a system operation and planning perspective. Systems of less than 5 MW are also exempt from having to register as generators.

Chapter 5 of the NER specifies the process for the connection of generators to the NEM. However, this process was originally designed to connect generators to the transmission network. An additional section (5A) has been introduced to standardize the connection for generators less than 100 kW that can be connected under AS4777.

Technical Framework

The technical framework for PV interconnection in Australia consists, at the highest level, of Australian Standards. State-based regulators set standards for network voltage and, in some cases, the network frequency. In other cases, the standards for frequency are set by the market regulator and applied to multiple state jurisdictions. Further technical requirements are specified by individual DNSPs. This framework is depicted in Figure 5.

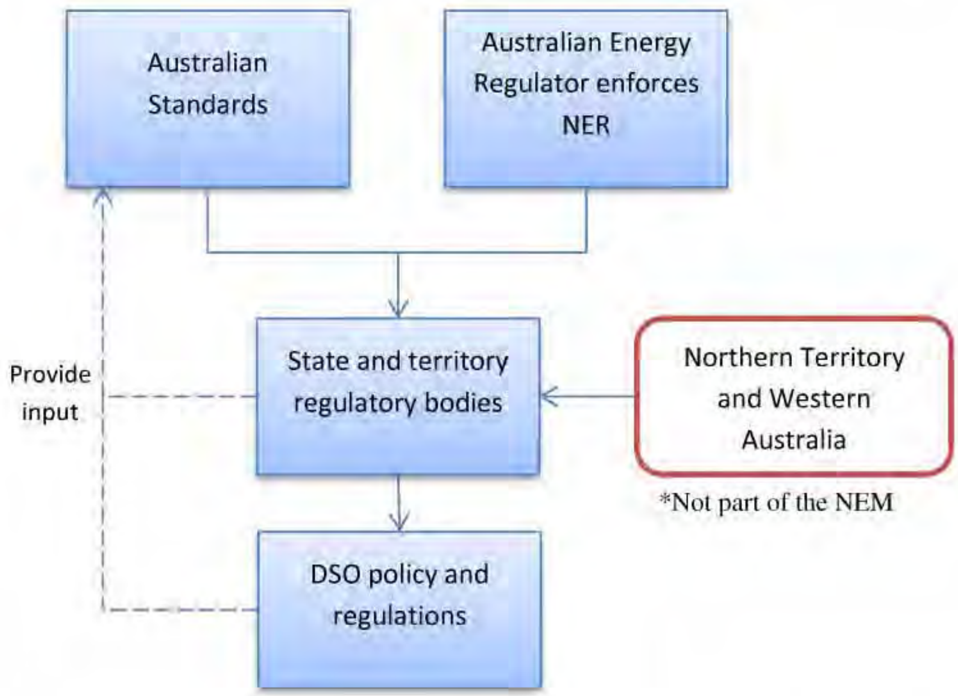

Figure 5: Technical framework for PV interconnection in Australia

The following Australian Standards apply to the connection of solar PV systems to the distribution network in Australia:

- AS4777—Grid connection of energy systems via inverters
- AS61000.3.100—Steady-state voltage limits in public electricity systems
- AS3000—The wiring rules

AS4777

The most current version of the AS4777 standard is from 2005. The standard is currently being revised, with a public consultation period completed at the end of August 2013. The existing AS4777 standard is divided into three parts: installation requirements, inverter requirements, and grid protection.

The key inverter requirements include

- Alternating-current (AC) voltage and frequency ratings are to be compatible with AS61000.3.100 (see below);
- Power factor is to be in the range of 0.8 leading to 0.95 lagging for all output from 20% to 100% of rated output;
- Total harmonic distortion (THD) (to the 50th harmonic) shall be less than 5%;
- The inverter shall conform to the voltage fluctuation and flicker limits as per AS61000.3.3 for equipment rated less than or equal to 16 A per phase and AS61000.3.5 for equipment rated greater than 16 A per phase;
- The inverter shall withstand a standard lightning impulse of 0.5 J, 5 kV with a 1.2/50 waveform; and
- The direct-current (DC) output of the inverter at the AC terminals shall not exceed 0.5% of its rated output current or 5 mA, whichever is greater.

The key grid protection requirements include

- The grid protection device shall operate if supply from the grid is disrupted, when grid voltage or frequency goes outside preset parameters, or to prevent islanding;
- The inverter set points should be in the range of f_{min} = 45 Hz–50 Hz, f_{max} = 50 Hz–55 Hz, V_{min} = 200 V–230 V, and V_{max} = 230 V–270 V for a single-phase system;
- The grid protection device shall incorporate at least one method of active anti-islanding protection; and
- Reconnection is permitted when voltage and frequency are in the acceptable range for at least 1 minute and the inverter energy system and the electricity distribution network are synchronized and in phase with each other.

In the proposed revision of AS4777, parts two and three of the current standard have been combined. The key changes are listed in Section 0.

AS61000.3.100

The AS61000.3.100 standard, published in 2011, sets a nominal supply voltage of 230 V, although the LV system was originally designed and specified at 240 V. It defines both an allowable operating range and a preferred operating range. The preferred operating range is +6% to -2%; however, the allowable voltage variation at the point of supply is +10% and -6%. The preferred operating range represents the 50 percentile value of voltage, whereas the upper and lower limits are the 99 and 1 percentile values, respectively (see Table 5 and Figure 6).

Table 5: System Voltage Requirements Under AS6100.3.100

Voltage	AS61000.3.100
Max. allowable	253 V (99%)
Max. preferred	244 V (50%)
Nominal	230 V
Min. preferred	225 V (50%)
Min. allowable	216 V (1%)

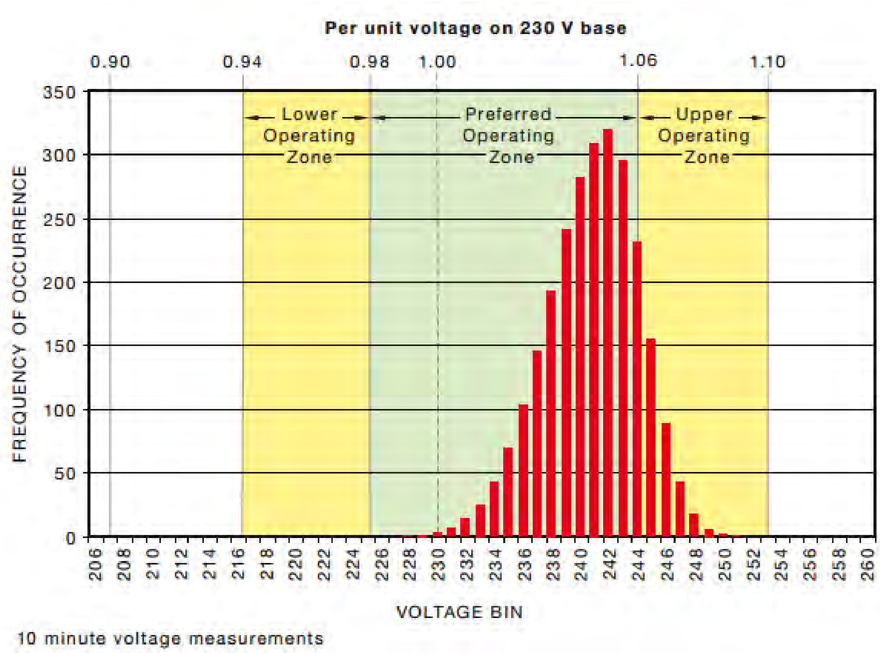

Figure 6: Voltage operating zone specified by AS61000.3.100

AS3000

Section 3.6.2 of the AS3000 standard specifies that a voltage drop of no more than 5% is allowed between the point of supply and any point in the electrical installation. The voltage drop limit applies between a solar inverter and the point of supply [24].

Power Quality Standards

The standards for network voltage are mandated individually by each state and territory. The standards for frequency are established either by the Australian Energy Market Commission (AEMC) or unilaterally for jurisdictions that are not part of the NEM. Table 6, lists the frequency provisions for the NEM regions as they are defined by the AEMC for a "no contingency or load event" [25, 26].

Because the AS61000.3.100 standard was only released in late 2011, not all jurisdictions have yet changed their local regulations to be consistent with this standard.

Table 6: Voltage and Frequency Requirements for Australian States and Territories

Quantity	Limit	ACT	New South Wales	Northern Territory	Queensland	South Australia	Tasmania	Victoria	Western Australia
Voltage	High	254	253	253	254	253	253	253	254
	Nominal	240	230	230	240	230	230	230	240
	Low	226	216	226	226	216	216	216	226
Frequency	High	50.25	50.25	52	50.25	50.25	50.5	50.25	51.25
	Nominal	50	50	50	50	50	50	50	50
	Low	49.75	49.75	47	49.75	49.75	49.5	49.75	48.75

DNSP Regulations

The DNSPs develop regulations based on the requirements of the state and territory regulator and the Australian Standards. These regulations address the connection procedure and the technical guidelines with which a PV system must comply. DNSPs typically set a system size limit above which a more detailed technical study is required. This is to provide a streamlined connection process for household customers. Some DNSPs also specify the voltage and frequency set points of the inverter. The set point values, where available, and the system size limits are summarized in Table 7.

Table 7: System Size Limits and Voltage and Frequency Inverter Set Points

State	DNSP	PV System Size Limit Before Technical Study Required	Voltage and Frequency Set Points			
			f(min)	f(max)	V(min)	V(max)
ACT	ActewAGL	10 kW single phase, 200 kW three phase	-	-	-	-
NSW	AusGrid	10 kW per phase	48–50	50–52	200	260
NSW	Endeavour	30 kW	48	52	190	260
NSW	Essential Energy	10 kW	48–50	50–52	200	260
NT	Power and Water Corporation	4.5 kW residential, 30 kVA for three-phase commercial	46	54	210	270
QLD	Energex	5 kW	48	52		255
QLD	Ergon	5 kW, 2 kW for SWER	-	-	-	255
TAS	Aurora	10 kW, or 30 kW three phase	-	-	-	-
SA	SA Power Networks	10 kW, 5 kW for SWER network	48	52	-	257
VIC	CitiPower	10 kW per phase, unless rural location	48.5	51.5	195	265
VIC	Jemena	10 kW per phase	-	-	-	-
VIC	SPAusNet	3.5 kW per phase SWER, 4.6 kW single phase, 5 kW per phase, three phase	-	-	-	-
VIC	Powercor	10 kW per site	-	-	-	-
VIC	United Energy	10 kVA per phase	-	-	-	-
WA	Western Power	5 kVA single phase, 30 kVA three phase	47.5	52		
WA	Horizon Power	10 kW per phase	46.5	53	190	265

Some DNSPs have introduced, or are considering introducing, capacity limits on the installed PV that can be connected to any one feeder, substation, or other network element. For example, Western Power has limits on embedded generation of 30% of the LV feeder capacity and 20% of the zone substation capacity [27].

Required Control Capabilities for Photovoltaic Systems

The Australian Standards do not currently contain provisions for control capabilities; however, a framework for implementing control capabilities is anticipated in the near future. This framework will be established through the upcoming revision to the AS4777 standard and the new AS4577.3.3 standard. The AS4577 set of standards cover demand response capabilities. These two future standards are discussed in a later section on "Upcoming Regulatory Changes."

Some DNSPs have already implemented limited control capabilities, primarily for larger systems. For example, Horizon Power specifies feed-in management requirements that apply for systems of more than 50 kW, and sometimes for systems between 5 kW and 50 kW of installed capacity [28]. These requirements specify that an active communication channel must be maintained so that the utility can control the

- Instantaneous active power;
- Reactive power set point; and
- Main system isolation circuit breaker.

Another example is from ActewAGL, which states that systems greater than 61 kW will be considered for SCADA integration with the network operator [29]. SA Power Networks specifies additional islanding protection of "a suitable protection relay with both Vector Shift and ROCOF protection elements incorporated with the relay" [30]. The system must also record and transmit to the utility quality-of-supply data, including THD and long- and short-term voltage flicker measurements. This is for systems of more than 10 kVA per phase.

Case Studies for High PV Penetration Scenarios

Detailed case studies have been undertaken on three Australian localities that are experiencing high PV penetrations: Alice Springs in central Australia; Carnarvon, a remote town in northern Western Australia; and Magnetic Island, a small community located 8 km off the coast of North Queensland (see Figure 7 for exact locations). Magnetic Island is connected to the main grid of the Australian NEM, whereas Alice Springs and Carnarvon are stand-alone grids utilizing predominantly gas generation. Key findings from these case studies are presented in the following sections.

Figure 7: Locations of high PV penetration case studies in Australia

Case Study 1: Alice Springs

The Alice Springs Electricity Supply system is a small autonomous network supplying a population of approximately 30,000 residential and commercial customers and with a load in the range of 15 MW to 55 MW and averaging around 26 MW. It is supplied by three centralized power generation stations consisting of a total of 19 primarily gas-fired generators, with a network of high-voltage (HV) sub-transmission and distribution feeders feeding an LV distribution system, all of which mainly supply electricity to urban customers. As such, the Alice supply system has particular operational characteristics that can be different than those of large interconnected electricity supply systems primarily because it has far fewer and smaller generators and loads spread throughout a relatively small network. In particular, the Alice system experiences a wider range of system operating frequencies both during normal system operation and during system events.

From a starting point of two grid-connected residential PV systems several years ago, there has been a significant increase in both the number and capacity of PV systems connected to the Alice network. This was driven by a number of factors, including broader support mechanisms for PV in Australia as well as the Alice Solar City project in Alice Springs itself. At the time of the case study, there were 528 PV systems connected with 2.1 MWp of capacity. This included 460 small residential PV systems, 39 commercial systems, 27 demonstration systems at a PV showcase facility, and 2 larger "iconic" PV systems.

Existing PV penetration at the system level is estimated to be approximately 4% to 5% for peak PV power penetration (i.e., midday on sunny days) and 1.5% for total annual PV energy generation. Present PV penetration levels at the HV feeder level are generally insignificant relative to normal feeder operating loads. PV penetration levels at the LV distribution feeder level are also relatively low but could be up to 30% of distribution transformer load at peak-PV power times on specific transformers with high numbers of PV systems. It is understood that there have not yet been any instances of reverse power flow through a distribution transformer. The connection of the Uterne 1-MW system in July 2011 bought the total installed PV capacity to 3.1 MWp. This is by far the largest single PV system on the network and is estimated to increase the system-level PV penetration figures to approximately 6.5% to 8% for peak PV power output and 2.5% for total annual PV energy produced) respectively. PWC intends to closely monitor the operation of the Uterne system on the network. It is now reported that Alice Springs has more than 4 MW of PV that is achieving up to 10% penetration by energy on summer afternoons [31].

Figure 8: Diagram of PV system distribution on the Alice Springs Network (status: 10/2010)

Table 8: Summary of Key PV Penetration Experiences/Issues on the Alice Springs Network

PV Penetration Experience/Issue	Comment/Status
Significant tripping of PV systems during system frequency drop events	2.1.1.1.1 Previously experienced during certain system low-frequency events. Steps have been taken by P&W to address this by changing inverter low-frequency trip requirements (i.e., reduced to 46 Hz). This issue has been resolved for the connection of future PV systems but not yet fully resolved for existing PV systems on the network. There has been no significant impact on network operation. Raises a related issue concerning the ability or otherwise of utilities to confirm and change settings for existing inverters.
Small PV fluctuations on system net load profile due to clouds	2.1.1.1.2 Recently observed (order of close to 1 MW over a period of minutes). No material impact on network operation as yet. To be monitored by P&W.
LV distribution system voltage management	2.1.1.1.3 Presently no problems with LV system voltage due to PV penetration. However, P&W has initiated a project to more closely investigate potential LV system voltage effects on a section of the network with high PV system penetration.
Reactive power management	2.1.1.1.4 Presently no problems with reactive power management due to PV systems. However, the general issue is currently being assessed/reviewed by P&W. Consideration is being given to larger systems (e.g., 100+ kW) providing reactive power support.
Other potential PV penetration effects: • Reverse power flow • Network fault detection • PV system islanding • Harmonic injection	⇨ Not presently an issue ⇨ Currently no issues due to PV systems ⇨ Not experienced ⇨ Not considered an issue (from PV systems)

Case Study 2: Carnarvon

The Carnarvon distribution network is an isolated gas/diesel generation grid with a relatively high penetration of dispersed embedded PV systems by the current Australian experience. This high PV penetration is coupled with a strong solar resource (an average daily solar insolation of 6.2 kWh/m^2). PV penetration is estimated to peak at 13% of system load at midday in both summer and winter. Consequently, impacts on the distribution network due to PV systems are starting to emerge. In 2011, the concerns about these impacts were sufficient enough for Horizon Power (the utility that owns and operates the Carnarvon distribution network) to apply a limit of 1.15 MWp of distributed PV system capacity on the distribution network. Given strong community support for PV in Carnarvon this has understandably created concerns regarding possible future PV deployment. Horizon Power is seeking to better understand the potential impacts of PV on the Carnarvon grid and their potential management, including facilitating this case study.

Approximately 200 km of overhead lines servicing approximately 5,300 people comprise the Carnarvon distribution network, which is primarily radial in nature with some long rural feeders. The peak system load to date is 11,600 kW, and the average system midday loads are approximately 6,800 kW in summer and 5,000 kW in winter. Sixty percent of the peak demand is from commercial/industrial loads, with the remaining 40% resulting from residential loads. Thirteen generator sets comprise the power station in Carnarvon, which is also owned and operated by Horizon Power. They are predominantly dual-fueled by gas and diesel and have a nominal rating of 22,100 kW, which is derated to 15,900 kW in summer. The generating strategy in Carnarvon is to operate with enough spinning reserve to cover the loss of the largest online generator. This also sets the limit for the amount of distributed PV in the town given the concern that some power system events might cause all PV to disconnect from the system at the same time when generating at maximum output.

Currently, there are 1,090 kWp of nominal PV capacity connected to the distribution network. The majority (57%) of the systems were installed in 2010 in part as a result of policy drivers such as a significant state feed in tariff for PV, which was subsequently discontinued due to far greater than expected PV system uptake. The average size of a PV system connected to the distribution network is 8.30 kWp, despite there being only one commercially-sized system (60 kW). This is significantly higher than the average system size on the main grid within Australia. The PV distribution in Carnarvon is also quite clustered, with one medium-voltage (MV) feeder loaded to 39% of its average midday load and distribution transformers loaded up to 70% of the rated capacity of the transformer.

Key Experiences to Date

This case study found that, in general, there were some instances of system-wide and localized challenges in the Carnarvon distribution network associated with the PV systems connected to the grid. Horizon Power is undertaking network studies and trials to permit further distributed PV systems to connect to the distribution network while maintaining a reliable and safe supply. It is possible that these trials will show that regulations, such as the 20% connection limit on distribution transformers, can be relaxed. If the trials and mitigation strategies prove to be successful, a relaxation of the hosting capacity may be possible; however, if this is the case, it is recommended that further PV systems are installed in a controlled and monitored fashion.

There are some key current and proposed strategies to mitigate the negative effects found caused by PV systems. Table 9 summarizes these for the identified PV integration challenges. Benefits associated with PV integration in Carnarvon are also presented in the table.

Table 9: Summary of the Key Findings of the Carnarvon Case Study

PV Penetration Experience	System-Wide or Localized	Summary of the Experience	Current/Proposed Management Strategies
PV systems impact on network stability due to inverter anti-islanding protection detecting significant frequency deviations	System	There has been one recorded instance of multiple PV systems disconnecting due to a system-wide frequency disturbance, resulting in additional load for the central generator to cover rapidly. A lack of standardization among inverter anti-islanding protection settings within AS4777 is also a concern.	Current: • Operating the network with sufficient spinning reserve to maintain the network if PV systems disconnect Trial: • Dispatchable load trial to increase system capability to respond to such disturbances Proposed: • Review of and PV inverter protection settings • Community solar farms with feed in management

Voltage rise in LV networks	Localized	Two recorded instances of significant LV network voltage rises have been identified in Carnarvon. Both problems have been resolved, and the networks were brought back within acceptable limits by reconfiguring the distribution transformer tap changer or line augmentations.	Current: • Rectification of phase imbalance with respect to both loads and PV system connections • Distribution transformer tap setting changes • Load shifting • Network augmentation Trial: • Voltage regulation technology
PV system impacts on network stability due to cloud fluctuations	System	There have been no recorded system-wide fluctuations in load due to PV output variability; however, significant fluctuations have been observed on a localized level. It is possible that with increased PV penetration, this effect will be more evident on the supply network.	Current: • Operating the network with sufficient spinning reserve to maintain network stability with PV system fluctuations Trials: • Cloud sensor technology Proposed: • Further monitoring of system loads and PV generation

Fires due to PV systems	Localized	There has been one reported instance of a fire caused by a PV system, made even more serious due to continued PV generation during the fire.	Current: • Management procedures are in place to ensure correct panel installations Proposed: • Extended firefighter training • Change to problematic junction box designs
PV system impact on planning strategies	System and localized	The variability of PV system output makes it difficult to plan for system peak loads as seen by the dispatchable generation. There is also a push for more commercial sized systems to connect to the network.	Current: • Work is being undertaken on forecasting the impact of PV systems on the network load levels Trial: • Horizon Power is testing a feed-in management system for a 300-kW system installed in February 2012.
System islanding	System and localized	Investigation has been undertaken into the possibility of network islanding due to PV systems and has concluded that it is extremely unlikely to occur in the current configuration.	Current: • LV network is earthed prior to work Proposed: • PV inverter protection settings are being reviewed in line with the impact on system stability and in line with studies mentioned above. Horizon Power would prefer that all inverters are set to a fixed value rather than be variable inside a range.

System harmonics from PV inverters	Localized	Past investigations on the Carnarvon network have indicated no prior problems with harmonics. Results examined in this case study reinforce that PV systems are having little effect on network harmonics.	Proposed: • Monitoring at higher PV system penetrations is important to ensure that the PV systems don't affect network harmonics into the future
Reverse power flow	Localized	Currently PV systems are causing localized back-feeding through some distribution transformers, but no significant effects are visible on the 22-kV network.	Proposed: • Monitoring at higher PV system penetrations and a review of protection schemes is needed to prevent potential future problems
Reduction in generator fuel use	System	The current PV system generation in the network is resulting in a generator fuel saving that is equivalent to approximately 830 tons of CO_2 per annum.	Benefit: • There is potentially significant value in such fuel savings depending on gas/diesel prices. The value of climate change abatement with PV is also potentially significant. By managing the spinning reserve strategy effectively and increasing the amount of PV in the system, these benefits can be maximized.
Offsetting of peak summer loads with PV generation	System	PV generation generally corresponds well to the peak system loads, implying possible deferral of network upgrades, and benefits can be further maximized by adjusting customer loads.	Benefit: • Analysis is currently being undertaken to estimate the amount that PV systems can contribute to peak demand reduction to fully realize this benefit in terms of system planning

Case Study 3: Magnetic Island

Magnetic Island is located approximately 8 km from the cost of the northern Queensland city of Townsville. Two 11-kV submarine cables connect the Australian mainland to Magnetic Island, where two 11-kV feeders extend east and west across the island, supplying a total of 1,992 customers throughout the 4 main residential areas of the island. The peak load between November 2011 and October 2012 was slightly more than 5 MW on December 27, 2011. Energy demand for an average day peaks at approximately 3,370 kW in winter and 3,417 kW in summer, with load growth historically driven by increases in the use of residential air-conditioning.

Townsville was one of the cities selected under the Australian government's Solar Cities program to trial distributed PV and other associated distributed energy technologies. The majority of the PV systems on Magnetic Island are small-scale (<10 kW) residential systems, with several larger systems of up to 22 kW and one 100-kW system at the public Solar Skate Park. As of early 2013, there were a total of 326 PV systems installed on the island, giving a total installed generation capacity of 1,102 kW, including the 100-kW system. The majority (735 kW) of the systems were installed between mid-2008 and the end of 2011 as part of the Solar Cities program, with an additional 367 kW installed since mid-2008 with support from the Queensland Government Solar Bonus Scheme and the Australian government Renewable Energy Target scheme.

As such, a high and increasing number of customers on Magnetic Island have PV systems. The peak PV penetration (PV generation contribution to meeting load) from November 2011 to October 2012 was 34% for the whole island and 35% for one of the 11-kV feeders, occurring during September. Forty-four percent of the 84 distribution transformers have more than 20% of connected customers with PV installed. In general, the PV is reasonably well distributed across the entire island, with 65% of distribution transformers having a penetration level of up to 15% (based on installed PV capacity/transformer rating). One distribution transformer has a 75% PV penetration, with a rating of 10 kVA and 7.5 kW of PV connected. The next highest distribution transformer penetration is 52%, with 26 kW of PV on a 50-kVA transformer.

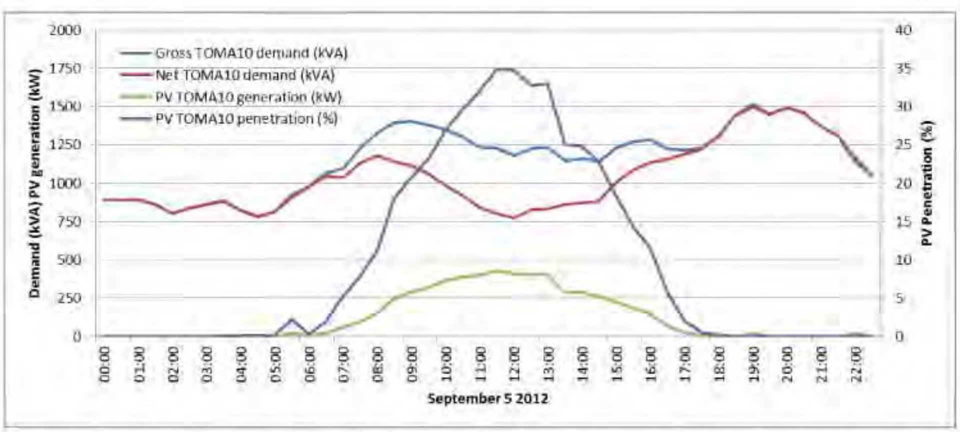

Figure 9: TOMA10 peak PV penetration day for the period from November 2011 to October 2012

As a result of participation in the Solar Cities Program, a relatively high penetration of distributed PV systems has been achieved on Magnetic Island compared to the current Australian experience. The penetration level is 22% (measured as PV capacity/peak load ratio; see Table 10, which is estimated to peak at approximately 32% PV contribution to load in some time periods and 35% on one of the two 11-kV feeders. PV penetration levels have increased rapidly throughout Ergon Energy's network. Indeed, a number of other network regions now have higher penetrations of distributed PV than Magnetic Island. For example, Hervey Bay is at 26.6% PV capacity/peak load ratio (14.3 MW of PV capacity installed with a 53.1-MVA peak load).

Table 10: PV Penetration Levels on Magnetic Island

PV Penetration Measure	PV Measure	Estimated Value	System Measure	Value	% PV Penetration
PV capacity penetration	Installed nominal PV capacity	1,102 kW	Annual peak load	5,050 kW	22%
PV peak power penetration – summer	Est. summer midday PV peak power	583 kW	Average summer midday load	2,914 kW	20%
PV peak power penetration – winter	Est. winter midday PV peak power	497 kW	Average winter midday load	1,984 kW	25%
PV peak power penetration – average	Est. average midday PV peak power	392 kW	Average midday load	2,372 kW	16.5%
PV annual energy penetration	Est. annual PV energy	2 GWh	Annual gross system load	39 GWh	5%
Maximum instantaneous PV penetration[4]	PV generation at time of max. PV penetration	698 kW	Load at time of max. PV generation	2,158 kVA	32%

Key Experiences to Date

The past decade has seen a range of challenges for Australian distribution networks as they face the challenges of aging assets and peak demand growth. Recent rapid distributed PV deployment comes within this complex and changing context. This report attempts to focus on the PV-related issues, but these issues are often difficult to separate from other distribution network issues, such as the issues associated with high peak demand from air-conditioning.

Table 11 below summarizes Ergon Energy's experience to date with PV issues and current and proposed strategies for managing any adverse past or potential impacts. The information is from interviews conducted with Ergon Energy employees and data collected

[4] Annual peak PV:load ratio

for this report. The main issue experienced by Ergon Energy due to high penetrations of PV has been voltage related. None of the other potential power quality issues—such as reverse power flow, power factor distortion, or harmonics—are currently of significant concern. Protection staff, however, raised network stability concerns in relation to islanding, though there is no evidence of this having occurred to date. All instances of voltage issues that have arisen have been addressed by Ergon Energy, and the company continues to trial and, when appropriate, introduce new technologies and procedures for both mitigating current voltage issues and avoiding new problems as PV capacity on Ergon Energy's network increases.

Table 11: Summary of the Experiences of High PV Penetration in Magnetic Island and Townsville

Summary of the Experience	Current/Proposed Management Strategies
PV Distribution System Voltage Management **A combination of large loads and distributed PV are causing a wide range of voltages to occur on LV feeders, particularly on high-impedance parts of the network, where voltages have been problematic before significant amounts of PV were installed, but may have gone undetected.** **Inverter HV disconnect settings greater than Ergon Energy's 255-V requirement (to comply with a statutory limit of 254.5 V) are being used by some installers.**	**Current:** In the event of a power quality complaint: • Advise customer if customer installation impedance is too high • Balance PV and loads across phases • Upgrade service mains or LV feeder—in some cases, this merely brings forward planned overall upgrades. • Augment or relocate the relevant distribution transformer (DTx) • Lower the tap on the DTx • Review the operation and settings of the network equipment General: • Test the fault loop impedance to determine the likely voltage rise and action prior to the installation of PV systems. • Educate installers to use correct inverter settings and check network impedance via fault loop impedance tests. **Trials:** • Static compensators (STATCOMs) for

Summary of the Experience	Current/Proposed Management Strategies
	voltage regulation • LV regulators • Reactive power injection • Variance test to check inverter set points after installation **Other Relevant Developments:** • AS4777 changes to reduce voltage drop at customer installation inverter switchboard <1%
Phase Imbalance **Customers' (loads and PV systems) are not balanced across phases. Unbalanced power flow can cause neutral phase voltage to rise and increase voltages on phases.** **Ideally, phase balancing would occur at the time of the PV system installation, but Ergon Energy does not currently have data on customer phase of connection.**	**Current**: • Balancing across phases in the event of a power quality complaint
Reverse Power Flow **PV generation > load can cause reverse power flow, which is of concern to protection staff and may reduce efficiency of the network.** **This is not currently of concern on Magnetic Island, and even in urban areas with a high penetration of PV, power quality engineers have not seen any switching or disconnection issues.**	**Current**: • Require network studies for proposed systems >5 kW (detailed below)
Protection and PV System Islanding	**Current**: • Protection study required for systems >30

Summary of the Experience	Current/Proposed Management Strategies

The major protection concern is related to the possibility of failure of inverter anti-islanding protection, due to a quasi-stable island, where PV feeds masks a fault, or other failure of the anti-islanding mechanism.
 	
No PV system islanding incident has been recorded. Outside of the protection group, this is not a major concern.
	kW
	
	• Systems of sufficient size that could export power such that the load and generation are balanced are not approved.
	
	• Ergon Energy inspects all large PV installations before connection.
	
	• Additional requirements for large systems may include:
	  ○ Inverters capable of absorbing Vars/inverter to operate with a set power factor
	  ○ Supplementary HV protections, such as overcurrent protection at the point of connection, neutral voltage displacement earth fault protection on the high side of the transformer
	  ○ Protection relays as per IEC60255
	  ○ Additional (parallel) active anti-islanding protection on top of what is required by AS4777
	  ○ SCADA monitoring for systems >1 MW

Network Planning and PV System Approval **Many applications for PV systems are being received, particularly associated with announcements of closures of government incentive schemes.** **Growing numbers of applications for large systems (>30 kW) are now also being received, requiring network studies.**	**Current:** • Systems < 5 kW are currently automatically approved, but this limit is under review. • Systems >5 kW require approval from asset management to ensure that they are network capacity sufficient. • Systems >30 kW are treated as large connections and subject to a network load flow study by a regional distribution

Summary of the Experience	Current/Proposed Management Strategies
	planning team and a protection study. **Proposed:** • Guidelines for the application to install a large PV system are under preparation to streamline the process.
Harmonics **Australian utilities have been concerned about the aggregate effect of large numbers of inverters producing harmonics of the same order. Harmonics can cause overheating and failure of equipment, such as transformers and customer motors, and also may cause neutral currents.** **This is a low-priority issue. Measured harmonics have been well within required standards and too small to be of concern, even where high penetrations exist. Air-conditioning has been shown to be a much more significant source of harmonics than PV inverters at high penetrations.**	**Current:** • ENA and the AS4777 standards working group continue to monitor the situation and ensure that harmonics from PV systems are not problematic. **Proposed:** • Where THD is an issue, Ergon Energy has identified the use of STATCOMs as a measure that can reduce the issue.
Power Factor **PV inverters operate at unity power factor, so they do not contribute directly to this problem; however, when a large percentage of the load is being supplied by PV systems, the residual load can comprise a high percentage of reactive power.** **This problem has not been experienced in Ergon's network to date. This issue is expected to become more significant as Ergon Energy begins using STATCOM devices to manage voltage issues.**	**Proposed:** • Inverters can potentially be used to supply reactive power.

PV does not contribute to reducing peak demand on Magnetic Island, which has a typical residential evening peak, but it does contribute to reducing the overall loading on network equipment and, importantly, contributes to the de-loading of distribution transformers on peak days in the lead up to peak demand. The Christmas period, shown in Figure 10, produces 7 out of the 10 peak demand days for the year, including the highest 6. The other 3 occur during Easter. The reduced demand (shown in red) during the day as a result of PV means a reduction in thermal stress on TOMA10, leading into the peak and improved lifetime through reduced loading throughout the year.

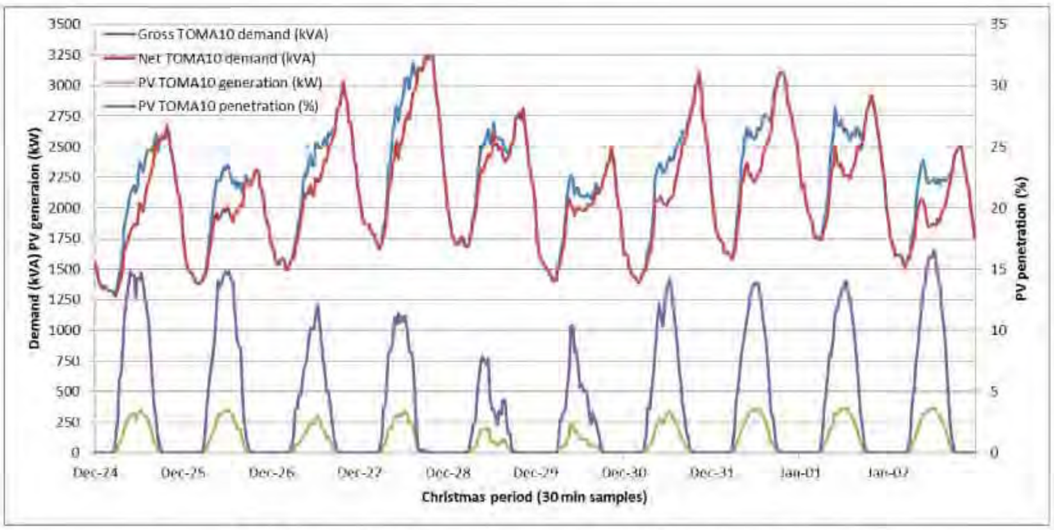

Figure 10: Impact of PV de-loading on TOMA10 on peak day

Conclusions

High and growing penetrations of mainly small distributed PV systems exist within Ergon Energy's distribution network. Magnetic Island is one such example of high PV penetration. To date, some voltage issues have arisen in high-impedance sections of the network, but these have been successfully resolved. These issues have occurred within the context of wider challenges, such as existing voltage management issues associated with highly variable and peak demand, which have largely gone undetected and hence unmanaged in the past.

Voltage issues to date have been successfully resolved through network balancing, adjustment, and minor augmentation. Ergon Energy has developed tests to detect voltage issues before or directly after PV system installation and is engaging with installers to ensure the correct inverter settings and use of these tests.

Despite some concerns about the potential for PV system islanding, no other significant impacts are currently being experienced. Minor reverse power flow has not caused any network operation problems, and inverters have not produced significant harmonics or caused power factor issues. There are different views within Ergon Energy on the potential risks of islanding, but, again, no recorded instances have yet occurred. Nevertheless, Ergon

Energy is proactively exploring management approaches for dealing with the higher PV penetrations, and other distributed energy technologies, that seem certain to come.

Lessons Learned from the Australian Experience

Australia does not yet have a high penetration of PV on an absolute megawatt or per-capita basis compared to some of the country's leading deployment of the technology. However, deployment has been almost entirely on residential rooftops, and the proportion of households with PV systems is notable in some states—approaching 20% in South Australia. Further, Australia has also seen significant PV penetrations on some of its stand-alone grids that serve remote townships.

Deployment of PV in the LV network of both urban and regional areas has occurred within a broader context of growing challenges for distribution network investment and operation, including increasingly peaked demand driven largely by the growing use of reverse-cycle air-conditioning, yet also generally falling energy demand due to a wide range of factors including PV but also improved energy efficiency. The impacts of PV can be difficult to separate from these broader issues in some circumstances, such as voltage management.

To date, the technical issues associated with this PV deployment appear to be generally modest, and DNSPs have had considerable success in managing them with relatively modest efforts. Voltage rise has been the most important challenge, and a range of approaches have been implemented to manage this. PV system response to frequency deviations has also been a particular issue for the stand-alone grids that were investigated, and there are questions of how spinning reserve can be better managed.

As PV penetrations climb in Australian distribution networks, it will be important that DNSPs are suitably engaged and supported to effectively and efficiently manage the issues that arise. Such management must, of course, be suitably integrated into the broader framework of DNSP investment and operation driven by other changes in the distribution network as well.

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

Australian Standards

A new version of the Australian Standard AS4777 was been made available for public comment in mid-2013. The submission period closed at the end of August 2013. Significant changes are expected because the current standard has been in place since 2005. Some of the changes that are expected relate to the following:

- Inverter set points will be revised, including a lower maximum voltage.

- The voltage drop between the inverter and the main switchboard is to be less than 1%, and the voltage drop between the main switchboard and the distributor point of supply is to be less than 1%.
- Systems of more than 5 kVA have to be connected across three phases.
- Balance requirements will be included in multiple-phase systems. In a three-phase system, the imbalance between the phases must be no more than 20 A, or 2% of voltage. If these limits are exceeded, the inverter must disconnect.
- An inverter must have the ability to offer power quality response modes through volt-watt response, volt/Var response, reactive power support, and power ramp-rate limits.
- An inverter will support demand response modes (DRM) 0 through to 5, and modes 6 to 8 should also be supported (refer to Table 12).

Table 12: Demand Response Modes for Inverter Performance

Demand Response Mode	Requirement
DRM0	Operate the disconnection device
DRM1	Do not consume energy from the grid
DRM2	Do not consume at more than 50% of rated power
DRM3	Do not consume at more than 75% of rated power AND Export reactive power if capable
DRM4	Increase power consumption (subject to constraints from other active DRMs)
DRM5	Do not export energy to the grid
DRM6	Do not export at more than 50% of rated power
DRM7	Do not export at more than 75% of rated power AND Consume reactive power if capable
DRM8	Increase power export (subject to constraints from other active DRMs)

The demand response capabilities that are anticipated in the revised version of AS4777 will be complemented by a new section of the AS4577 standard. This standard contains provisions for the control of electrical devices that can alter electricity demand in response to an instruction from a remote agent. In practice, this remote agent is the DNSP.

AS4577 already provides operational instructions for the use of demand response functionality in air-conditioners and swimming pool pumps. PV inverters will be covered in an upcoming addition.

National Electricity Rules

In 2010, an amendment was made to the NER to include Chapter 5A, titled "Electricity Connection for Retail Customers" [32]. Chapter 5A will be introduced into state and territory legislation as part of the National Energy Customer Framework (NECF) and has already commenced in the ACT and Tasmania [33]. The NECF transfers responsibilities for the sale and supply of energy from the states to the AER. This will give the AER jurisdiction of connections in the distribution network. It also provides a simplified process for connecting nonregistered embedded generators.

The Victorian regulator, the Victorian Competition and Efficiency Commission, states that "Chapter 5A will largely replace the State-based regulation that supplemented embedded generator connections prior to…the NECF" [34]. It is envisaged that a similar process will take place in other jurisdictions that implement the NECF.

Under chapter 5A, DNSPs must have a model of standing offers for basic connection services that has been approved by the AER. One of these offers must be for retail customers who are micro-embedded generators. The term "micro-embedded generator" is defined as the type of embedded generation unit "contemplated by … AS4777" [7]. Currently, this would include systems of up to 10 kVA per phase; however, it is anticipated that the scope of AS4777 will be redefined in the upcoming revision.

The implementation of the NECF and Chapter 5A of the NER is intended to streamline the connection process for embedded generators, including solar PV customers. New South Wales, Victoria, and South Australia intend to introduce the NECF; however, the Queensland government is yet to decide whether the NECF will be introduced in that state [33]. At this stage, the extent to which the NER will replace state legislation for PV interconnection is unknown.

Austria

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Table 13 shows relevant statistics on PV generation and power consumption in Austria.

Table 13: Statistics on PV Generation and Power Consumption in Austria

Statistic	Value	Year
Installed PV capacity (nationwide)	0.61 GW	Status: 12/2013 [35] REF2_2_1 and PV Austria estimation
Peak load (nationwide)	11.3 GW	Status: 12/2012 [35]
Total generation capacity	23.2 GW	Status: 12/2012 [35]
Total energy generated by PV in 2012	337.5 GWh	Status: 12/2012 [35]
Share of PV on total energy consumption in 2012	0.5%	Status: 12/2012 (estimation)
Share of installed PV capacity connected to HV level	0%	-
Share of installed PV capacity at HV/MV substations	0%	-
Share of installed PV capacity connected to MV level	5%	Status: 12/2012 (estimation)
Share of installed PV capacity at MV/LV substations	No data	-
Share of installed PV capacity connected to LV level	95%	Status: 12/2012 (estimation)
Average size of PV system	No data	-

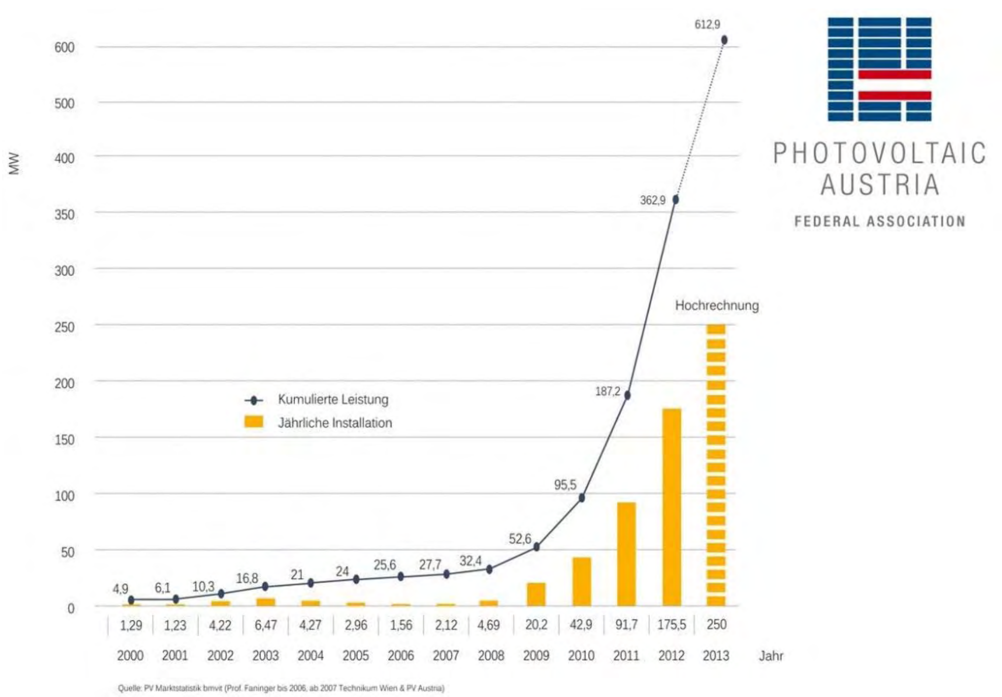

Figure 11: Development of PV capacity in Austria from 2000 to 2013 (Source: PV Austria http://www.pvaustria.at/2013/11/pv/)

The National Distribution Grid Structure

Austria's distribution grid structure and operation strategies are rather similar to the German one and is therefore not explicitly described here.

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Legal Framework

In Austria, the overall legal framework for the electricity market and the operation of generation, including the renewable energy source grid, is defined at the national level, whereas the detailed implementation is governed by laws at the federal level. Consequently, the regional laws may differ in details; however, these differences are not very significant with respect to renewable generation interconnection.

The main document defining the legal framework is the law for the organization of the Electricity Sector (Elektrizitätswirtschafts-und-organisationsgesetz 2010, or ElWOG) [36]. This law establishes the main common rules for the generation, transmission, distribution, and supply of electricity and the organization of the electricity market, regulates fees, and makes provisions with regard to accounting.

According to the federal electricity laws, Austrian grid operators are obliged to connect renewable generation to the grid; however, grid operators are obliged to connect only if the connection is feasible from a technical as well as economical perspective. In case of necessary grid reinforcements, the law does not define who has to cover the costs. In practice, costs are either covered by the renewable energy source operator or shared between the renewable energy source operator and grid operator, based on the contractual agreement.

Technical Framework

In Austria, the fundamental technical framework for the grid interconnection of distributed generation (DG) and thus also PV is defined in the "Technical and organizational rules for operators and users of transmission and distribution networks (TOR)" [38]. The TOR represents the national grid code and is part of the so-called "market rules" for the liberalized electricity market. The market rules have a special legal status and are contractually binding for users and operators of electricity networks.

Of the six main parts of the TOR, there are two documents that are of special relevance for the grid connection of PV. The first one, TOR D2 [38], describes procedures for the assessment of network interferences and states limits for the permissible impact. Although it is primarily dedicated to the assessment of loads, a special section provides guidelines for the treatment of generators. Parallel operation issues—such as installation, protection practices, voltage control, and others—are covered by TOR D4 ("Parallel operation of generation units connected to distribution networks") [39]. With the latest revision of the document, from September 2013, a number of additional requirements related to control and grid support capabilities has been added, in particular for larger systems connected to MV grids.

In addition to the nationwide guideline, some distribution network operators (DNOs) impose additional control and grid support–related requirements or use specific protection devices to guarantee the voltage quality. These are usually specified by the DNOs themselves. They are based on the local grid situation and the capacity and technology of the distributed generator, and they are subject to frequent changes and modifications.

Maintaining the voltage quality is the main constraint that defines the amount of PV that may be connected to the distribution grid. According to Austrian electricity market rules, grid operators have to meet the requirements of the EN 50160. This standard defines the required voltage quality for MV and LV customers during normal grid operation.

Required Control Capabilities by Photovoltaic Systems

PV systems that are to be connected to the LV and MV distribution grids need to provide certain control capabilities that are defined by the TOR D4.

Reactive Power Control:

Depending on the capacity of the generation plant, different requirements apply to the provision of reactive power.

Table 14: Requirements for Reactive Power Control for PV Systems

Capacity of the Generation Plant	Requirement	Reference
$S_N < 3.68$ kVA	No control requirement (power factor shall be >0.95	[40]
3.68 kVA $\leq S_N \leq$ 13.8 kVA	Minimum power factor of 0.95 (over/underexcited), set point defined by DNO	
$S_N > 13.8$ kVA	Minimum power factor of 0.95 (0.90 if required due to local needs) (over/underexcited), set point defined by DNO	

The reactive power control strategy and set points are defined by the DNO and depend on local grid conditions. For this purpose, the TOR D4 defines a number of options that may be necessary, such as

- A fixed cosφ(P) characteristic,
- A fixed cosφ,
- A reactive power as a function of the voltage Q(U) characteristic, and
- A fixed reactive power Q.

For generation systems connected to the MV level, the provision of reactive power can be either realized autonomously (e.g., fixed preset power factor or voltage-dependent reactive power provision Q(U)) or via remote control. For generation connected to an LV grid, only autonomous (without communication link to DNO) reactive power provision methods are used.

Active Power Control:

Generation plants with a system capacity of more than 100 kW need to implement active power control on demand of the DNO.

For smaller plants, there are no common requirements for active power control; however, some DNOs require an external control unit for smaller plants above 5 kW.

Case Studies for High PV Penetration Scenarios

In 2010, several demonstration projects focused on the integration of PV in distribution networks (especially LV) were launched.

In the project "morePV2grid" (FFG 829867, 2010–2013) [42] [43] [44], local control concepts for active grid support by PV inverters were developed and validated. These concepts—namely cosφ(P), volt/VAr (Q(U)), and volt/watt (P(U))—are based on mechanisms that control active and reactive power flows to keep voltage levels within the required range. Consequently, the controls aim toward increasing the PV hosting capacity of LV grids. Their local character refers to the fact that the controls are based on locally measurable factors only and therefore do not require any communication links. The functional as well as the effective validation of the control concepts were performed by means of a comprehensive field-test series in a real LV grid with an increased PV penetration level.

The project "DG DemoNet – Smart LV Grid" (FFG 825441, 2011–2014) [45] investigated and demonstrated more-complex concepts. In three demonstration areas with high PV penetration, the voltage is controlled by PV inverters (as in the previously mentioned project) that have control parameters that can be updated online remotely through the smart metering system. In addition, distribution transformers featuring on-load tap changing (OLTC) are also used in the demonstration areas. This project therefore considers a coordinated control of PV inverters, an OLTC distribution transformer, and e-vehicle charging stations.

The results presented here are mainly from the first mentioned project "morePV2grid"; the final report was published recently [46].

In the final stage of this project, the voltage control concepts developed and tested through lab tests were implemented in the field. For these field tests, an LV from a network supplying a residential area in a village—and therefore on that mainly supplies households (about 40)—has been selected. This feeder is made of a common section (about 230 m) that is then divided into two sub-feeders, the longest of which is almost 600 m. Five PV installations totaling approximately 15 kWp (see Figure 12) are connected to this feeder. This installed power might appear very small, but at the view of the local network properties this PV generation leads to a voltage rise of about 4.9%, which represents more than 160% of current planning criteria (maximum voltage rise of 3%). To achieve this with limited power, the feeder was reconfigured (alternative switching) and the installations (all single phase) were connected to the same phase (L3).

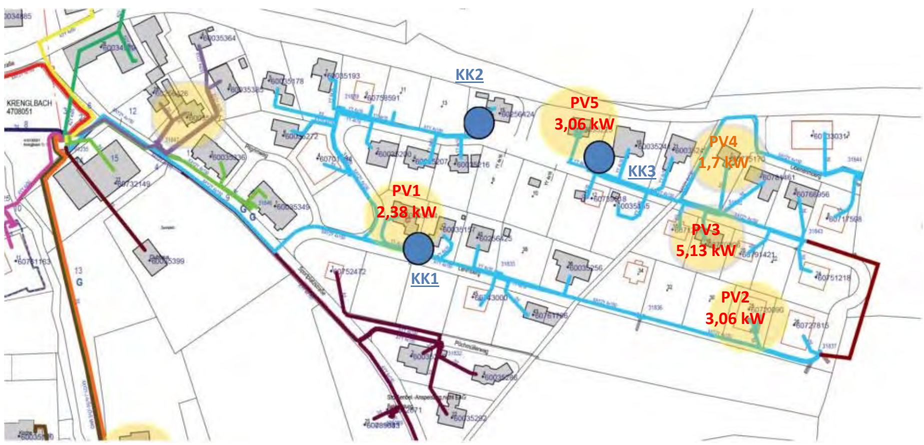

Figure 12: Network overview of Feeder 9 [46]

To investigate the behavior of the PV inverters with local voltage control features, several measurement systems have been used. The measurement data have been stored in a common database for ease of further processing.

- MV-voltage at transformer station
- LV voltage in three distribution cabinets (see Figure 12)
- Standard inverter monitoring at four installations
- Power quality measurement at the farthest PV installation

In addition to the functional validation (to demonstrate that the voltage control implemented into the inverters behaves under real conditions as intended), another objective of the field tests was to quantify the benefit of this control and compare it to the values obtained in simulations.

To quantify the compensation of the voltage rise achieved with the different control modes, a validation concept has been developed. It consists of comparing the cumulated probability distribution of the voltage for a control mode and for a reference case (without control). To limit the impact of external effects (voltage variations in the MV network, non-constant load conditions), only sunny working days have been considered (see [46] for a detailed description of the concept). In addition, instead of directly using the voltage values, the voltage difference between a distribution cabinet and the last PV installation has been used. This allowed eliminating the impact of the MV network in the validation process. Further, the investigated control modes—(Q(U), Q(U)&P(U), cosφ fix, and cosφ(P))—have been parameterized on the basis of the measurements from the reference phase (without control). The voltage levels are not close to the absolute limit (because the voltage level of the MV network is rather low in this area), thus the control settings have been moved to smaller voltage values. The settings of the Q(U) and P(U) controls mentioned in the following are:

<u>Q(U):</u>

- $U \leq 0{,}98$ p.u. $\rightarrow Q=Q_{max}=S_n \times \sin\varphi_{max}=0{,}43 \times S_n$;
- $U<1.01$ p.u. und $U>0.99$ p.u. $Q=0$;
- $U>1.03$ p.u.$\rightarrow Q=-Q_{max}=-S_n \times \sin\varphi_{max}=-0{,}43 \times S_n$;

<u>P(U)</u>

- $U>1.03$ p.u. $\rightarrow P = P(U)$ curtailment with 100%/V

Figure 13 and Figure 14 show some of the results of the functional validation for a Q(U)&P(U) control in the form of the PQ and Q(U) diagrams, respectively. The basis for these diagrams is the high-resolution power quality measurement data at the farthest PV installation. The reduction of the reactive power for voltage values greater than 2.5% shown in Figure 14 is due to the power factor limitation (cosφ>0.85) combined with the P(U) control.

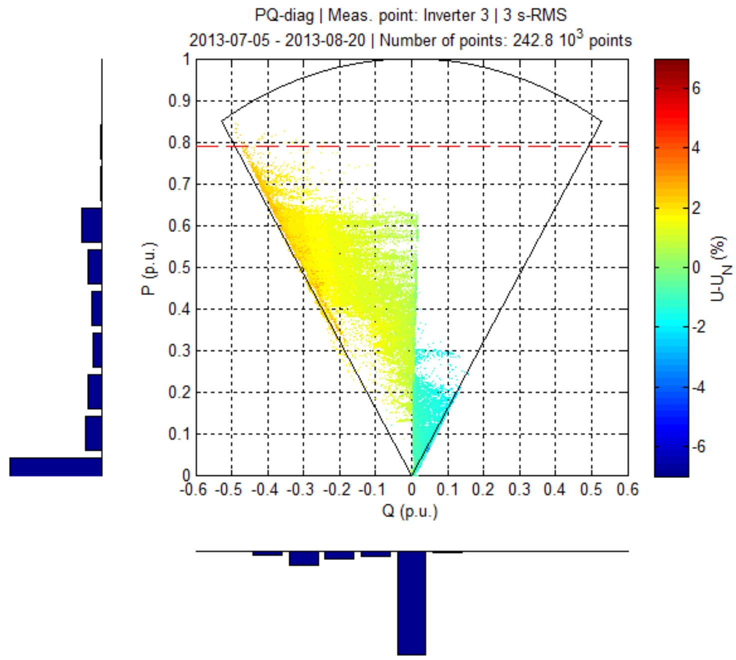

Figure 13: PQ-Diagram of Inverter 3—3-s RMS average [Test Q(U)&P(U)] [46]

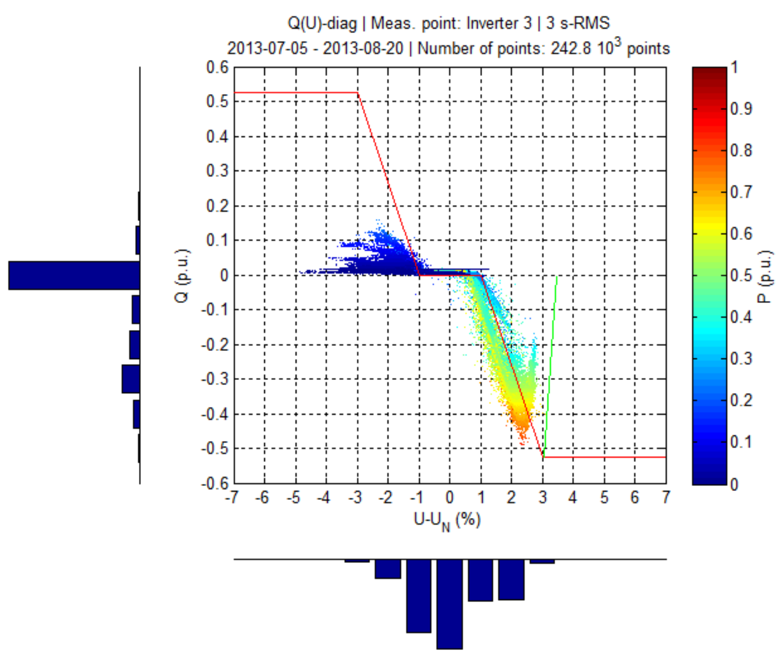

Figure 14: Q(U) diagram of Inverter 3—3-s RMS average [Test Q(U)&P(U)] [46]

In addition to the data analysis performed for the functional validation, the compensation of the voltage rise due to the voltage control modes has been evaluated. Figure 15 shows an example of the evaluation of the Q&P(U) control compared to the reference case (without control). The effect of the control can be mainly observed as expected for HV values. The compensation of the voltage rise between these two distribution cabinets amounts to about 0.75%, which represents about 2.25% of the nominal voltage when considering the whole feeder.

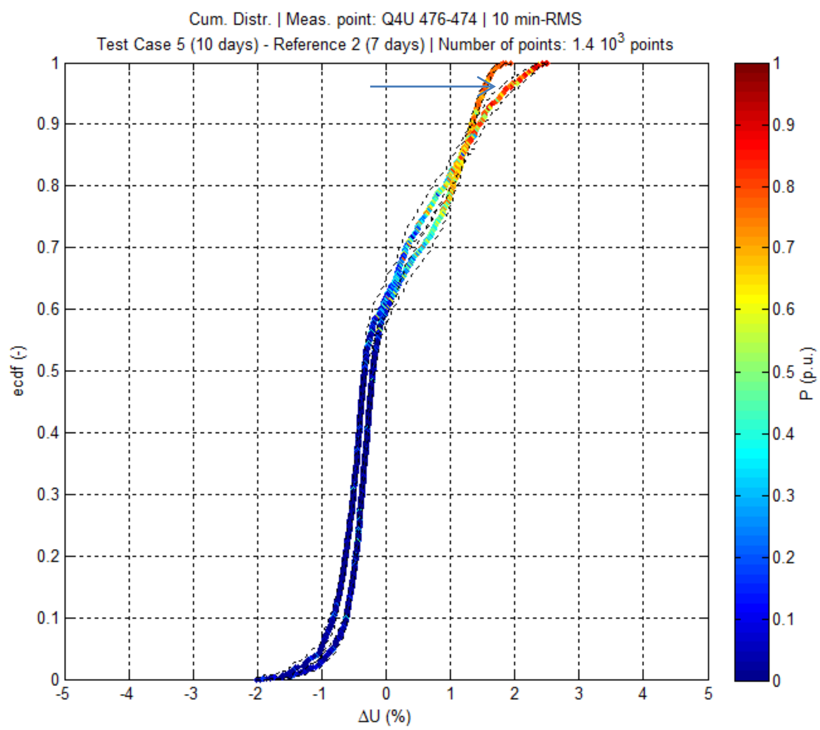

Figure 15: Cumulated distribution of the voltage difference between two distribution cabinets for sunny working days—10-min RMS average values [Test Q(U)&P(U)] [46]

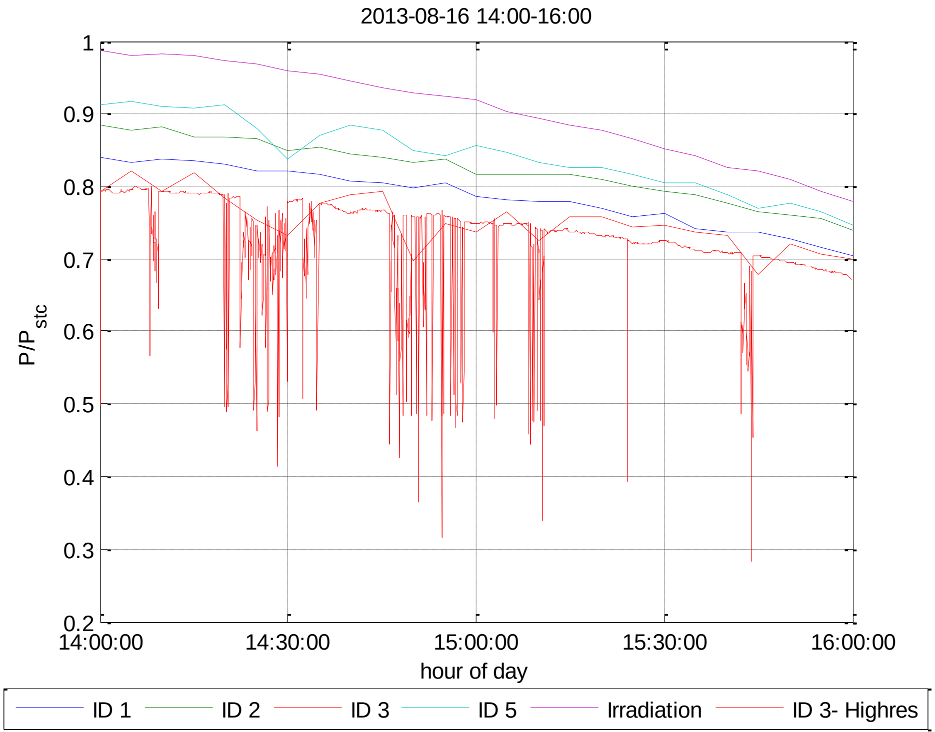

Figure 16: Active power curtailment from the P(U) control—3-s and 5-min RMS average [Test Q(U)&P(U)] [46]

Figure 16 shows the normalized (STC) active power infeed of four of the PV installations (the fifth one is not controlled) between 14:00 and 16:00 on a sunny day. This figure shows that only the two farthest installations actually curtail their output power (about 2.5% of the yield for this period).

As a conclusion of these field tests, the effectiveness of the control modes could be validated: the voltage rise could be compensated by 1.5% (reduction of almost 30%) with reactive power only, which corresponds to the value obtained by the simulations.

In addition to these investigations, numerous simulations have been performed to try to generalize the conclusions. A few of the findings are summarized below:

(1) The compensation of the voltage rise in cable network is significantly smaller than in overhead line networks; however, a compensation of almost 20% can be reached with common cables (e.g., 150 mm^2 see equation (1) and Table 15).

(2) The voltage drop over the transformer reactance can be rather large for old, small transformers (large, short-circuit voltage and low power)—1.5% of the nominal voltage for a 50% penetration and a 6% short-circuit voltage. See equation (2) and Table 16.

(3) As generally known, reactive power control is more effective in overhead line networks. In addition, a small transformer with a large, short-circuit voltage leads to an even stronger effectiveness. Such conditions are generally met in older networks.

However, considering that such networks are generally upgraded partly for other reasons than high PV penetration (e.g., reliability), the actual value of reactive power–based voltage control in older networks must be carefully considered.

$$\boldsymbol{\Delta U \approx \frac{R \cdot P}{U_N^2} \cdot \left[1 - tan(\varphi) \cdot \frac{1}{R/X}\right]} \tag{1}$$

$\boldsymbol{\Delta U}$	Relative voltage rise
$\boldsymbol{\varphi}$	Feeding angle
$\boldsymbol{R}$	Resistive part of the network impedance (resistance)
$\boldsymbol{X}$	Inductive part of the network impedance (reactance)
$\boldsymbol{P}$	Nominal power
$\boldsymbol{U_N}$	Nominal voltage

Table 15: Compensation of the Voltage Rise for Cable and Overhead Lines (for cosφ=0.90)

	Overhead Line		Cable	
Cross-Section[5] (mm^2)	R/X	Compensation @cosφ=0.90 (%)	R/X	Compensation @cosφ=0.90 (%)
50	1.9	26.1	7.2	6.8
70	1.4	34.4	5.3	9.1
95	1.1	45.6	3.8	12.9
120	0.8	57.1	3.2	15.2
150			2.6	18.6
240			1.7	29.2

$$\Delta U \approx u_X \cdot \frac{P}{S_N} \cdot tan\,\varphi \tag{2}$$

ΔU	Voltage drop over transformer reactance
$u_X \approx u_K$	Short-circuit voltage (transformer reactance in p.u.)
P	Installed PV power in the LV network
S_N	Transformer nominal power
$tan\,\varphi$	Corresponding to **cos φ**

[5] Material: Aluminium

Table 16: Voltage Drop Over the Transformer Main Reactance (for cosφ=0.90)

	P/S_N=10%	P/S_N=20%	P/S_N=50%	P/S_N=100%
u_k=4%	0.2	0.4	1	1.9
u_k=6%	0.3	0.6	1.5	2.9

Finally, a short economic analysis of active power curtailment has been performed within this project [44]. In this study, the same feeder has been considered, but the PV penetration has been highly increased (3 kWp per house).

With this high PV penetration scenario, some installations must curtail their active power output. The annual yield loss has been assessed and is shown on Figure 17. Although the maximal curtailment reaches more than 7% of the annual yield for a single installation, the overall yield loss for the whole feeder amounts to only 0.8%.

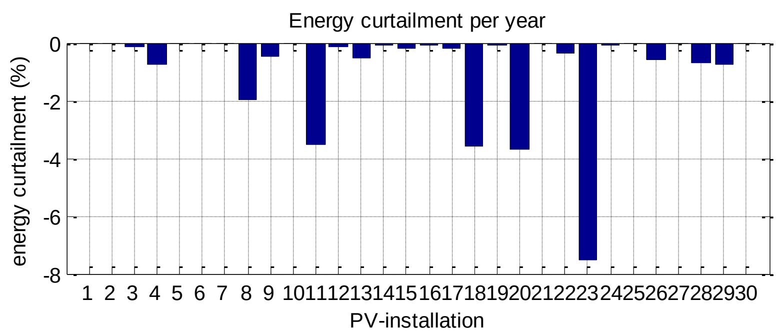

Figure 17: Curtailed energy per installation [44]

In addition, the financial impact of this curtailment has been evaluated for prosumers with a self-consumption regime and for a feed-in-tariff regime. For this the exact conditions must be considered because the value of the amount of lost energy depends on whether or not it would have been self-consumed (Figure 18). The maximal curtailment of almost 7% of the annual yield represents about 23 €/year, which corresponds to about 4% of the revenues that this installation would generate with the current FIT.

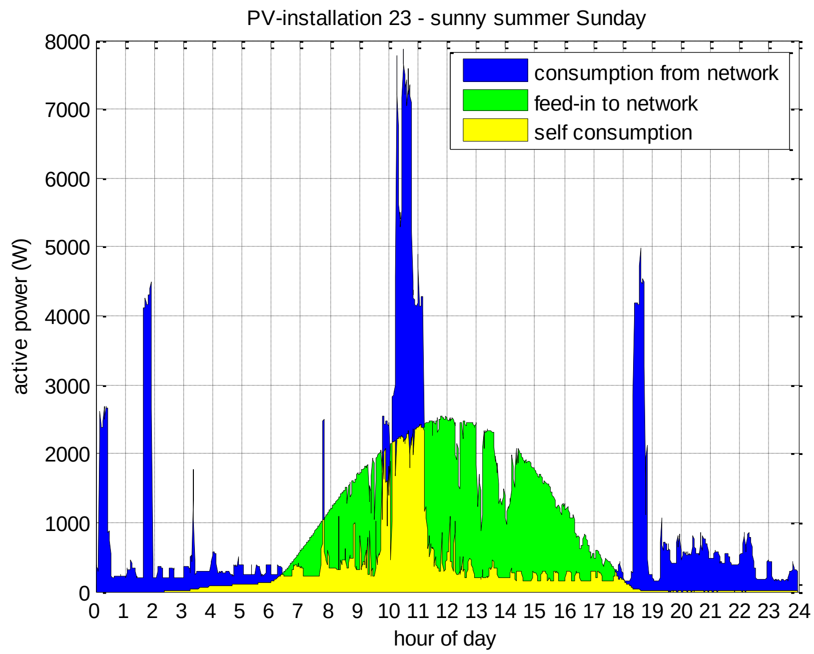

Figure 18: Self-consumption diagram for Installation 23 (on a sunny summer Sunday) [44]

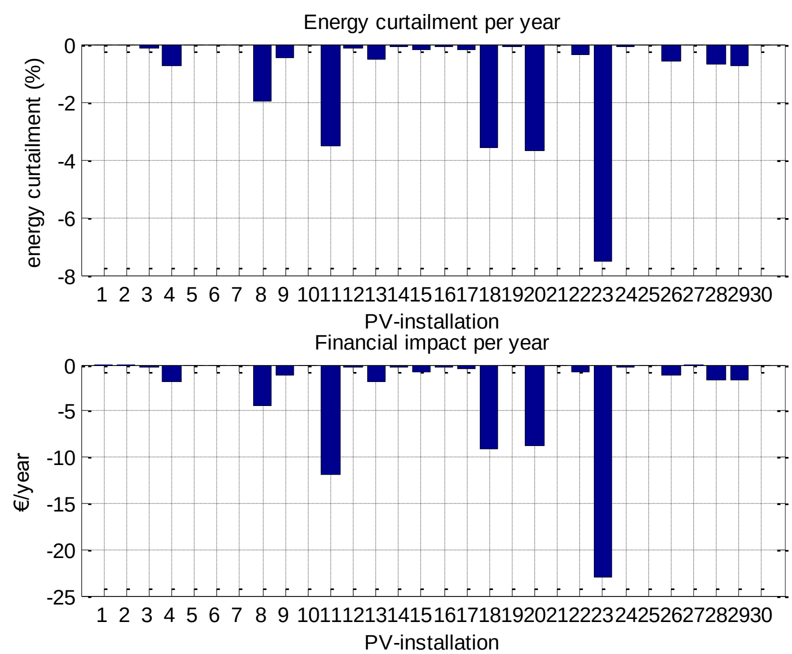

Figure 19: Financial impact of the power curtailment [44]

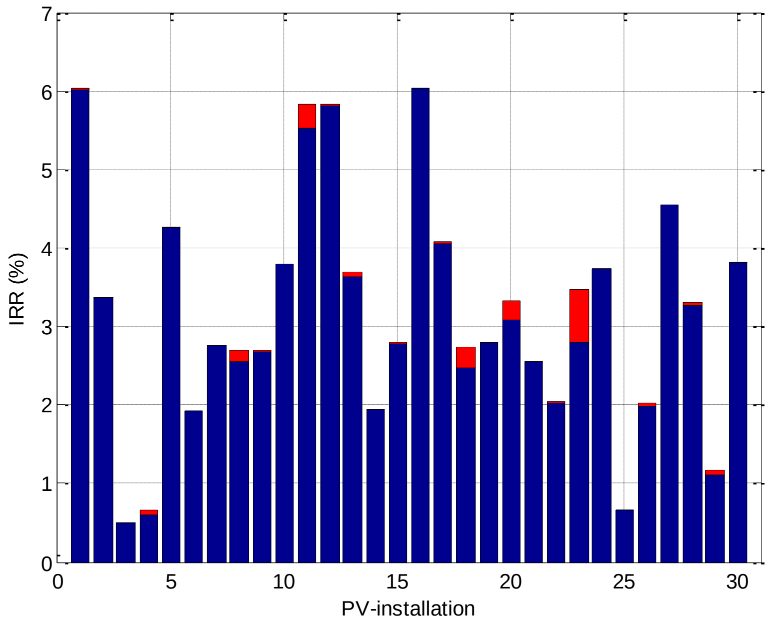

Figure 20: Impact of the power curtailment on the IRR for the 30 installations [44]

Finally, the impact of the power curtailment on the profitability of the PV installation has been quantified by analyzing the internal rate of return (IRR) for a lifetime of 25 years. For this a total cost of €6,750 per installation (€/kWp 2,250) and a subsidy of 400 €/kWp have been considered. The results of this analysis are shown in Figure 20, where the red area corresponds to a decrease of the IRR due to power curtailment. Depending on the rate of self-consumption, the internal rate of return is between 0.5% and 6% per year. This figure shows that for the most affected installation (23), the maximal financial impact is about 0.7 percentage points (IRR decreases from 3.5% to 2.8%).

In conclusion, voltage control is a valuable alternative to network reinforcement to enhance the hosting capacity of LV networks. In addition to the Q(U) control, which allows compensating part of the voltage rise caused by the PV infeed, a P(U) control has been implemented to guarantee that the voltage limits can be met. The P(U) control is seldom activated but ensures that the voltage limits are met while avoiding repeated disconnections from the grid.

The simulations made for a high penetration case study assuming 3 kWp/roof showed that the amount of active power curtailment necessary to maintain the voltage below the limit is rather limited (up to 7% for the most affected installation and less than 1% for the whole feeder). The resulting financial impact is also limited and is smaller under a self-consumption regime than under a feed-in-tariff regime. However, the regulatory framework for such an active power curtailment at the distribution level is still missing and shall be addressed to allow its deployment. By implementing such a voltage control, the hosting capacity could be extended by more than 40% compared to the case without control when considering a “smart planning approach” and by more than 800% when considering existing planning rules. These figures shall be carefully used because new planning rules are needed for networks with a high share of generation featuring smart grid functionalities. The relation between self-consumption rate and revenue losses has been investigated. The actual impact of the P(U) control depends on the network topology and the distribution of the installations (load and PV) along the feeder and among the phases. The impact of the individual local situation plays only a minor role compared to the overall power-flow: ensuring a high self-consumption at one particular installation does not necessarily means that the impact on the network (e.g., voltage rise) is low and that curtailment can be avoided.

The behavior of the neighbor prosumers is influencing the voltage, and a dedicated shifting of the load (with or without storage) has a positive influence, especially if the whole neighborhood is participating. Due to local effects and a potential high imbalance between phases, the use of a single-phase storage system to increase the self-consumption can worsen the voltage profile.

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

As of today, even if the connection guidelines have been revised recently (2013), a wide implementation of the voltage control concepts successfully demonstrated in various projects is still not happening. Reasons for this are the

- Lack of standardization,
- Large number of alternatives,
- Rising complexity of the planning when using such controls, and
- Opened regulatory questions.

In particular, the use of a reactive power–based voltage control alone does not provide any guarantee that the voltage will stay within the limits. Of course, over-voltage situations are in practice impossible due to the over-voltage protection, but when seeking a smart way of meeting the voltage quality targets while maximizing the PV penetration, proper solutions are needed. In addition to a reactive power–based voltage control, an active power control can provide the previously mentioned guarantee. However, many regulatory questions must be answered beforehand (e.g., allocation/repartition of the curtailment costs).

Another topical issue is the billing of reactive power from generators participating or not participating in the system operation (direct reactive power provision or reactive power–based voltage control).

Belgium

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Table 17 shows relevant statistics on PV generation and power consumption in Belgium.

Table 17: Statistics on PV Generation and Power Consumption in Belgium

Statistic	Value	Year
Installed PV capacity (nationwide, 31/12/2012)	2,501 MW	Source:[47], Section 2.3
Peak load (nationwide) in 2012 (7/2/2012 18h30)	14,234 MW	Source: [47], Table 3.3.2.2.1
Total net generating capacity (31/12/2012)	20,813 MW	Source: [47], Section 2.3
Net generation in 2012	74,985 TWh	Source: [47], Section 2.2
Electricity consumption in 2012	84,758 TWh	Source: [47], Section 2.2
Total energy generated by PV in 2012	1,628 TWh	Source: [47], Section 2.2
Share of PV on total electricity consumption in 2012	2%	Source: [47], Section 2.2
Share of installed PV capacity connected to HV level	<<	Status:
Share of installed PV capacity connected to MV level	<	Status:
Share of installed PV capacity connected to LV level	>>	Status:
Average size of PV system	9 kW	Status:

The National Distribution Grid Structure

The Belgian distribution grid is generally constructed as a mesh (large rings) on an MV level and as a mesh or radial feeders on an LV level. The grid is operated in a radial way by opening the MV ring connections. Whenever a part of the network is down because of a fault, the network behind the fault can be supplied by opening the breaker right after the fault and reclosing the ring where it was previously open.

The voltage in the transmission grid is subject to large variations. The voltage limits on distribution level are detailed in the power quality standard NBN EN 50160. It requires the 10 min mean root mean square (RMS) voltage values to be between 90% and 110% of the nominal voltage during 95% of the week.

To control the MV voltage to a stable value, HV/MV transformers are equipped OLTCs. Due to the discrete nature of the tap positions, the voltage on the MV side of the transformer is maintained only within a certain deadband, defined by the tap positions. To ensure voltages according to the standard, the voltage variation band is divided in an MV and an LV part. Given the (foreseen) loading of the grid, the MV grid topology and cable sizes are chosen to keep the maximum voltage drop within 0.06 p.u. This leaves some margin for additional voltage drop over the MV/LV transformer and the more resistive LV grid. The voltage drop over a fully loaded transformer is assumed to be 2%, and the LV grid is finally designed to handle an additional voltage drop of 6% [48]. As generally both minimum and maximum electrical load in an existing grid used to increase over time, the DSO could adjust the decreasing voltage by changing the tap of the MV/LV transformer. This voltage management approach is visualized in Figure 21.

According to this approach, a voltage band of 0.04 p.u. remains for voltage increases along the MV feeders, LV feeders, and within the PV installation. When the MV/LV tap cannot be changed to increase this band for voltage rise (and decrease the band for voltage drop), voltage problems cannot be directly solved. In that case, the DSO will need to reinforce the grid or use storage, curtailment, or reactive power control, as will be discussed below.

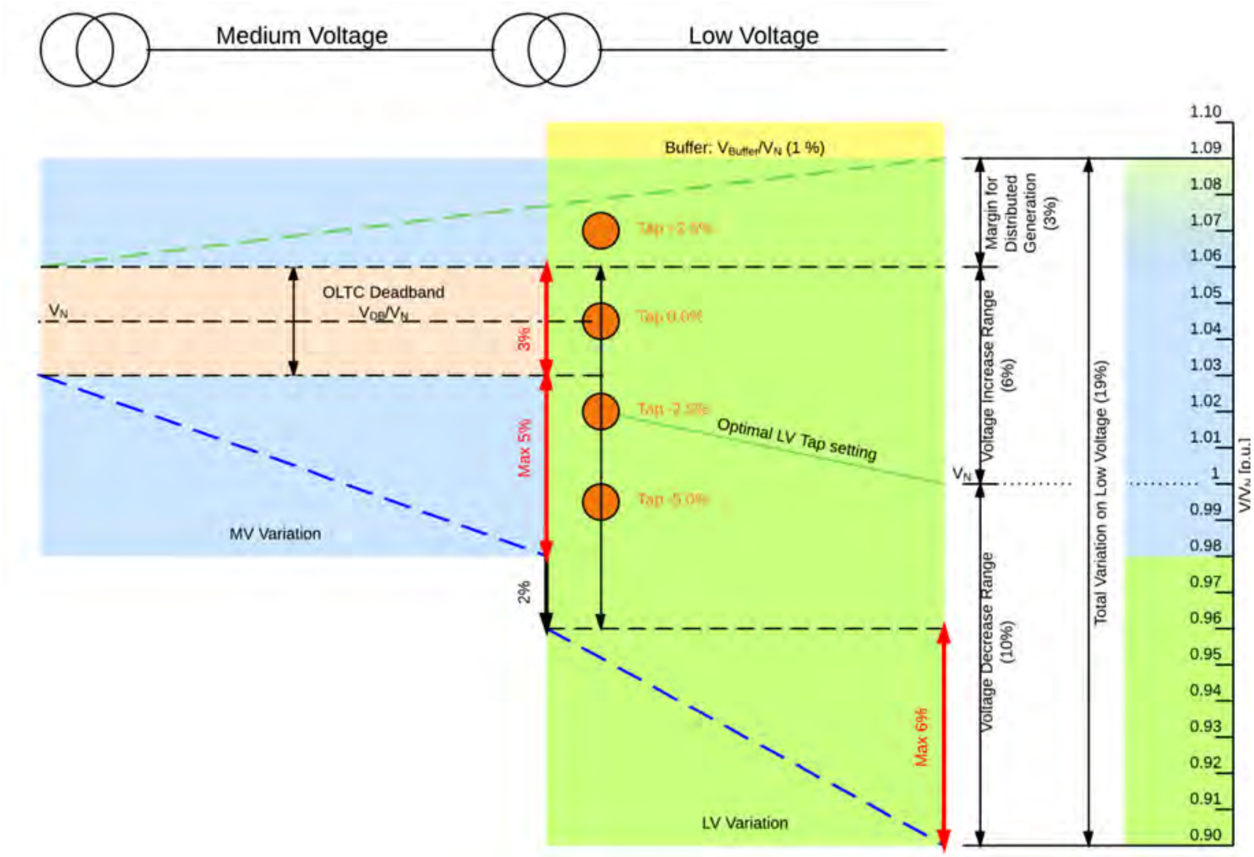


Figure 21: Example of distribution grid voltage management in Belgium

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Requirements

PV owners in Belgium can contact the DSO in case of power quality issues with their installation. Before any actions will be taken by the DSO, some requirements need to be fulfilled.

For systems with a PV inverter rating up to 10 kVA [49], the voltage rise within the internal grid (behind the meter) may amount to maximally 1%. Also, the voltage rise on the connection cable between the main feeder and the meter may amount to maximally 1%. If one of these requirements is not met, the internal grid or connection cable should first be reinforced at the expense of the PV owner. In cases where the inverter size exceeds 5 kVA, a three-phase grid connection is required. If the PV installation would be connected with a single-phase connection cable, the DSO will provide a three-phase connection cable at the DSO's expense. If all of the above conditions have been verified and the voltage problems persist, the DSO will take measures in the grid to improve the power quality. Solutions may be the redistribution of loads and production, installation of additional control infrastructure, or the installation of a new cable.

For systems with a PV inverter rating above 10 kVA, the DSO will perform a feasibility study for the grid connection. If applicable, the DSO will offer a quotation for the required network reinforcement works. In addition to the requirements mentioned above for smaller inverters, the maximum allowed current imbalance for these systems is 20 A.

Required Control Capabilities by Photovoltaic Systems

Specific technical requirements for decentralized production units connected to the distribution grid are given in the Synergrid technical electrical prescriptions C10/11[47][50].

Contribution to short-circuit power:

The contribution of a PV system (plant) short-circuit power at its connection point should remain limited. The maximum contribution depends on the system size:

- 500% Sn for systems with Sn ≤ 1 MVA
- 400% Sn for systems with 1 MVA < Sn ≤ 4 MVA
- 300% Sn for systems with 4 MVA < Sn ≤ 10 MVA
- 150% Sn for systems with 10 MVA < Sn

With Sn the nominal apparent power.

Voltage control:

The voltage of the grid should stay within the applicable boundaries both with and without the presence of the PV system. Therefore, the DSO can impose a certain power factor to PV installations. Installations below 1 MW must always operate with power factors > 0.95. For larger installations, the grid operator can request any reactive power–to–active power ratio between -0.1 (inductive) and 0.33 (capacitive). For larger installations (>2.5 MVA), addition telemetric and telecontrol measures may be imposed. Further, active power variations are restricted to an impact of 3% on the grid voltage.

Frequency control:

PV installations commissioned after January 1, 2013, should contribute to the frequency control of the grid by reducing their active power according to a droop function when the frequency exceeds 50.2 Hz. Older installations that disconnect at high frequencies are allowed to reconnect only after the frequency is within the range of 47.5 to 50.05 for at least 60 seconds.

Islanding:

Islanding within a private installation is allowed. Islanding situations in which the public distribution grid is involved are prohibited.

Fault ride-through (FRT):

PV installations are not allowed to disconnect during voltage dips reaching voltage levels below the line indicated in Figure 22.

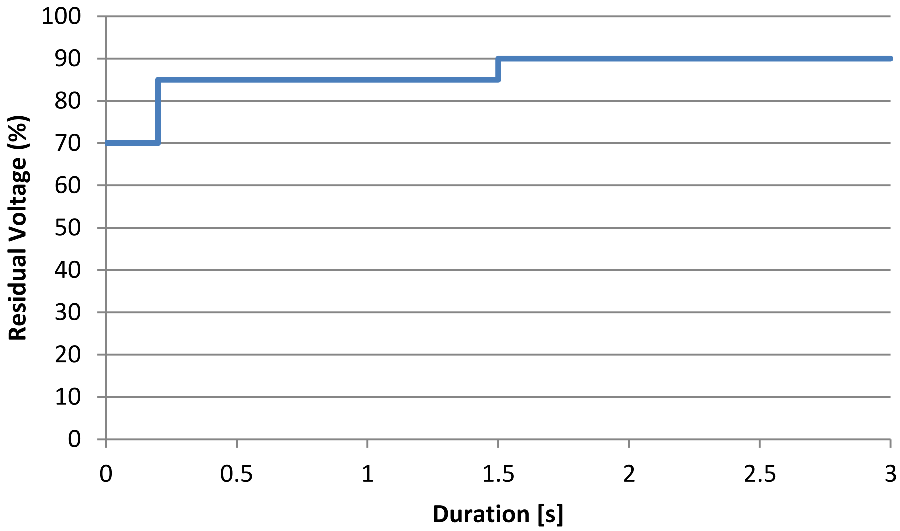


Figure 22: FRT requirements for Belgium

Case Studies for High PV Penetration Scenarios

MetaPV

MetaPV [50] is a research and demonstration project funded by the European Commission on grid hosting capacity for variable renewable power. It is the first practical demonstration of a European PV smart grid, implemented in Belgium on Infrax LV and MV distribution grids. MetaPV aims to assess, on a technical and financial level, the possibility of doubling grid hosting capacity for PV power at a fraction of the cost of the cost of standard grid reinforcements through the use of smart inverters and controls to reactive power levels. MetaPV is a first step toward a reliable solution for PV integration, and it would prove that more PV, with advanced control systems, can be a source of greater stability.

The demonstration started in autumn 2012 and will end in spring 2014. Different voltage control strategies are being demonstrated on more than 85 PV installations, connected both on LV and MV. These voltage controls are based on PV inverters with reactive power control and electrical storage systems.

Reactive Power Voltage Control

Over-voltages on network feeders are the most common PV integration problem. They are caused by reverse current from net PV power injection in the grid. Because PV inverters are technically capable of delivering a wide span of reactive power, this functionality can be used to enable a controlled voltage drop over the reactance of lines (or cables) and transformers. In MetaPV, different reactive power control are being tested.

- Fixed power factor (PF)
- Fixed reactive power (Q)
- PF = f(active power P)
- Q = f(voltage U)

Demonstrated Impact on the Grid Voltage

These different solutions have been demonstrated in the field. Preliminary analysis [51] showed that to draw solid conclusions more data collection is required so the stochastic behavior of the loads on the feeder voltage is statistically canceled out. The current measurements still show some inconsistent results due to the "limited" data set.

However, the first results are promising. Figure 24 shows the probability of exceeding 250 V for different reactive power controls for different residential inverters in the demonstration. It can be observed that for most inverters the probability is in any case zero due to the location of the inverter on the feeder or the presence of continuous loads. For the inverters where the voltage does sometimes exceed 250 V, the probability of occurrence was reduced in most cases with reactive power controls.

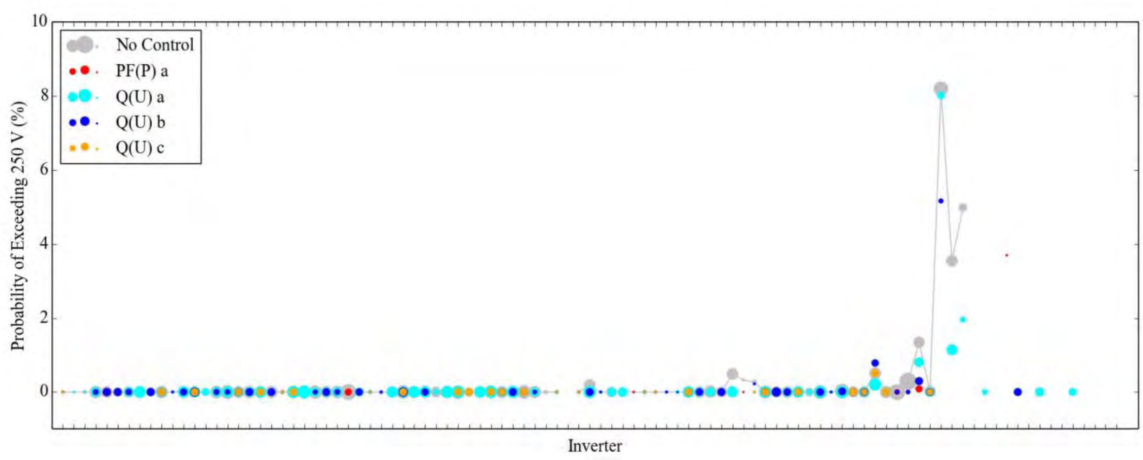


Figure 23: For all but one inverter, the reactive power controls reduce the probability of voltages exceeding 250 V (as far as they are not zero). For that one inverter, the probability of exceeding 251 V was found lower for Q(U)-b than without control. Circles on the same vertical line belong to the same inverter. The size of the circles is a measure of the available measurement data. For the circles at the far right, there was not sufficient data without reactive power control within the measurement period.

Economic Evaluation

A methodology for comparing different implementation options is described in [52]. The concrete outcome of these cost analyses are subject to many assumptions on the eventual implementation of the considered solutions. Important aspects that need to be taken into account are, among others:

- The voltage level on which the PV is connected, the related costs for network modifications, and the electrical characteristics, reflecting the performance of different solutions (e.g., a higher electrical reactance of the network feeders favors reactive power control);
- The foreseen required hosting capacity in the future. Are solutions implemented in a stepwise approach or rather imposed for all as a retroactive change in the requirements for existing systems?;
- For distributed solutions such as local reactive power control, whether and how installations with different properties (local voltage level, reactive power capability of the inverter, system size) are treated needs to be considered;
- The distribution of the loads and generators between the phases of the feeder; and
- The economic analysis is based on data of one complete year and a uniform electric load over the feeder. In the simulation tool, it was assumed that all OPEX solutions, which do not require any additional equipment, are exhausted. This means that the (fixed) MV/LV transformer tap setting is already optimized to lower the LV voltage as much as possible without causing under-voltage problems during high load conditions. Also, it is assumed that all generation and loads are evenly distributed over the three phases to obtain balanced voltages.

More technically, all the assumptions applicable in [52] were followed, with the additional assumptions that:

- All inverters on the feeder are retrofitted to have reactive power capabilities;
- All inverters can operate as low as PF = 0.9;
- The central (supervisory/ coordinated) reactive power control is able to gather the feeder voltages in real time and optimally dispatch the inverters;
- The local reactive power control is implemented as a Q(U) function that is able to keep the voltage below the limit at all times. Note that with this control the injection of reactive power will no longer be the same for all inverters on the feeder;
- Storage costs amount to 500 EUR/kW for the converter and 364 EUR/kWh for the full setup behind the converter (lead-acid technology); and
- Different inverter communication strategies were considered, including:

- Real-time control over private SCADA network that allows the DNO to change the inverter active and reactive power settings in real-time and in a secure way;
- Standard control over private SCADA network that allows the DNO to change the inverter settings/characteristics in a secure way but with a certain delay;
- Standard control over the internet that allows the DNO to change the inverter settings/characteristics in a certain delay such that security is limited to access authorization requirements of inverter; and
- Standard control over the internet (inverter integrated communication) that is the same as above but with reduced infrastructure costs thanks to inverter integration.

Discussion of Results

The results allow comparing grid reinforcement to inverter control in different aspects, including:

→ Different levels of hosting capacity increase;

→ Local (Q(U), P(U)) versus central (supervisory) inverter control;

→ Different implementations of local inverter communication;

→ Curtailment versus storage; and

→ Low versus MV feeders.

All these aspects are brought together in one overview for LV (**Fehler! Verweisquelle konnte nicht gefunden werden.**) and one for MV (Figure). The x-axis shows the increase in hosting capacity, and the y-axis describes the corresponding cost. The bars show the costs without communication equipment for each scenario. The markers above the bars indicate the total cost including the communication equipment. Note that central control always requires real-time control equipment. Also note that the cost of network reinforcement is approximately constant because these works are typically not performed in an incremental way. Moreover, the civil works largely outweigh the cost differences between the different cables required for each case.

As a general observation, energy storage is relatively expensive compared to both energy curtailment strategies (yellow versus red, green versus blue) and grid reinforcement (yellow, red versus grey). Although storage is under continuous development and different technologies could be used, the current price limits the economical use of storage to cases in which very limited amounts of storage can avoid more expensive grid reinforcements. This restriction is more pronounced on the LV feeders.

On LV, in all cases where inverter control is more efficient than grid reinforcement, local control strategies come out as the most economically viable. However, central control is overall more efficient in terms of reactive and active power efficiency (OPEX), and these benefits do not outweigh the additional communication needs (CAPEX) in this case.

One of the project objectives was to allow DNOs to increase the grid's hosting capacity for PV by 50% at only 10% of the costs of traditional grid reinforcement. The results show that for LV feeders, this would be feasible with active power curtailment and using inverter integrated modules for communication. These are two difficult constraints because (1) current European Union regulation does not foresee renewable energy curtailment at the distribution level and (2) inverters with integrated communication are new (as are reactive power capabilities) and existing PV systems can take advantage of this only when the complete inverters need to be replaced. Note that although communication is not absolutely required for local control, it may be preferable to prevent a lock-in with unchangeable inverter settings at a later stage when the network requirements change.

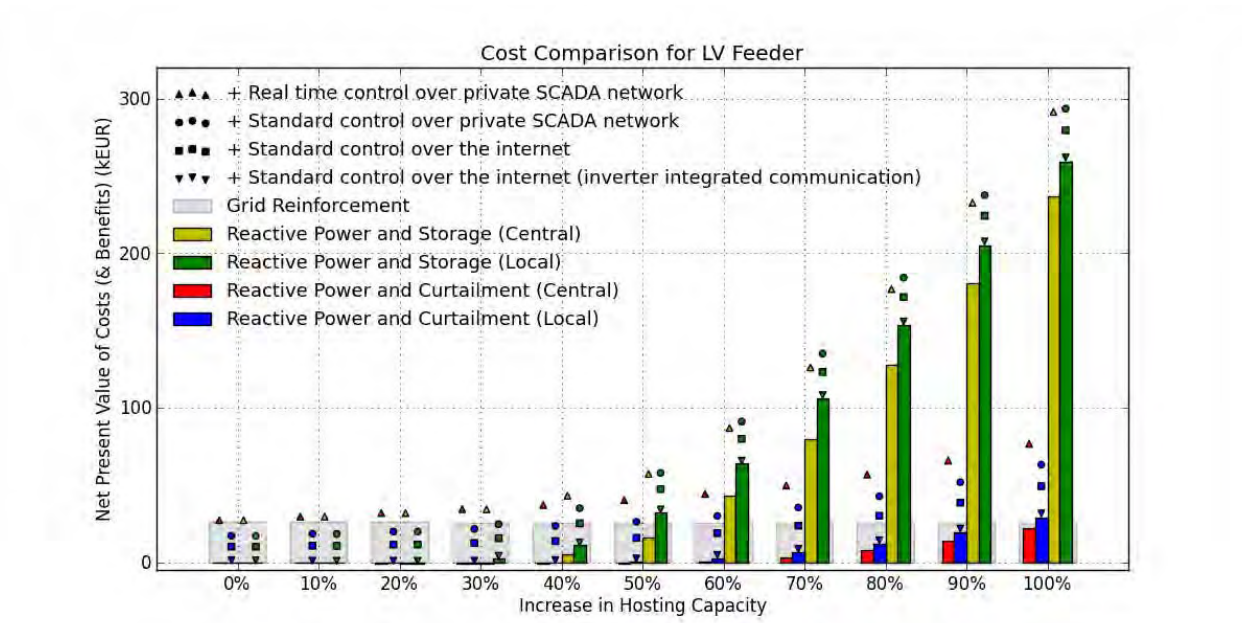


Figure 24: Increasing the LV grid-hosting capacity for PV with inverter control functionalities can be an economical solution for small increases in hosting capacity and basic communication infrastructure.

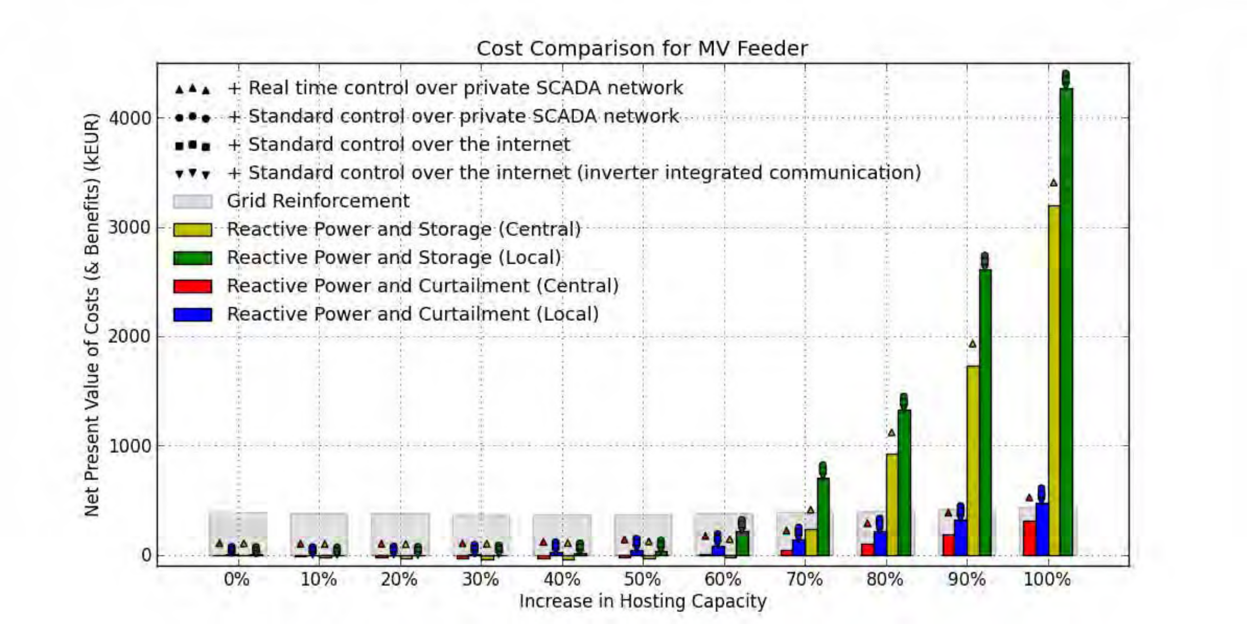
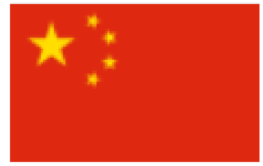


Figure 25: Inverter control can be a good way to increase the hosting capacity on MV levels. Due to the higher impact on reactive power, storage (or curtailment) needs become important only above a 50% hosting capacity increase.

To increase the hosting capacity with 50% on MV feeders, all solutions are more cost-efficient than grid reinforcement. This is attributed to the high impact of reactive power (low R/X ratio of the grid) and the relatively larger PV system size, reducing the communication cost per installed PV capacity. Local reactive power and storage control is the most efficient and stays below 15% of the grid reinforcement cost. Note that in this particular case storage performs better than curtailment because the network losses are being reduced during the storage discharge period.



China

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Table 18 shows relevant statistics on PV generation and power consumption in China.

Table 18: Statistics on PV Generation and Power Consumption in China

Statistic	Value	Year
Installed PV capacity (nationwide)	8 GW	Status: 2012 [53]
Installed PV capacity in 2012	4.5 GW	Status: 2012 [53]
Peak load (nationwide)	674 GW	Status: 2012 [54]
Total generation capacity	1,145 GW	Status: 2012 [55]
Total energy generated by PV in 2012	3,700 GWh	Status: 2012 [56]
Share of PV on total energy consumption in 2012	≈ 0.1%	Status: :2012 [56]
Share of installed PV capacity connected to HV level	≈ 63.6%	Status: 2012 [53]
Share of installed PV capacity connected to MV level and LV level	≈ 36.4%	Status: 2012 [53]

The National Distribution Grid Structure

HV, MV, and LV distribution networks comprise the distribution network in China. The voltage levels are divided as follows:

- The HV distribution network is usually supplied by 35 kV, 66 kV, or 110 kV, as well as 220 kV for high-density load.
- The MV distribution network is supplied by 6 kV or 10 kV, with only a few by 20 KV.
- The LV distribution network is supplied by 220 V/380 V.

HV Level: During the normal operating condition, the voltage bias of the point of common coupling (PCC) between a PV plant and power system should between $-10\%U_N \sim +10\%U_N$. Five typical structures are commonly used for the HV network in Chinese city, including radiation, ring, link, T-type, and hybrid wiring. The radiation type is suitable for a 110(66)-kV end substation and a 110(66)-kV station without a second source. The π-wiring with two sources is applicable in the areas where there are needs for strong connection, frequent changes in operation, or severe requirements for load density and reliability between two 220-kV-substations. The chain-wiring with two sources applies in situations when

1) two or three 110(66)-kV substations are located in the same transmission corridor, which can supply source lines on the unified tower; or

2) there are needs for strong connection, frequent changes in operation, or severe requirement for load density and reliability between two 220-kVsubstations.

The hybrid wiring is suitable for regions in which load grows very fast and requires high reliability.

Table 19: Basic Information on HV Level

Voltage	Nominal Line-Line Voltage Voltage range normal operation	35 kV, 66 kV, or 110 kV The sum of the absolute value of positive bias and negative bias of UN,LL no more than 10% [57]
Grid Layout	System topology Phase configuration Installation type	Radiation, ring, link, T-type and hybrid wiring Three-wire/three-phase Overhead lines/cables
Capacity	Typical nominal capacity of DG	G＞6 MWp

MV Level: The MV distribution network in China is mainly based on 10 kV. Some large industrial enterprises use 6 kV. During the normal operating condition, the voltage bias of PCC should be between -7%UN~+7%UN. The MV distribution network includes two basic wirings: the radiation-type wiring and the ring-type wiring, by cable and overhead line.

Table 20: Basic Information on MV Level

Basic Technical Guideline: Technical Requirements for Connecting a PV Power System to a Distribution Network		
Voltage	Nominal line-line voltage Voltage range normal operation	10 kv/6 kV ±7% $U_{N,LL}$ [57]
Grid Layout	System topology Phase configuration Installation type	Radial and meshed systems Three-wire/three-phase Overhead lines/cables
Capacity	Typical nominal capacity of DG	G≤6 MWp

LV Level: The LV distribution network wiring is composed of 220-V/380-V overhead lines and cable lines. It usually uses the radiation-type wiring and supplies users along the line directly. During normal operating conditions, the voltage bias of PCC should between -10%UN~+7%UN. For area with high-density load, the supplied radius of LV overhead lines should be controlled within 150 m. For areas with low-density load and concentrated users, the radius should be controlled within 200 m, and the max radius is no more than 400 m.

Table 21: Basic Information of LV Level

Basic Technical Guideline: Technical Requirements for Connecting a PV Power System to Distribution Network		
Voltage	Nominal line-to-line Voltage	220 V/380 V
	Voltage range normal operation	-10% $V_{N,LL}$ ~+7%$V_{N,LL}$
Grid Layout	System topology	Mostly radial, in urban areas also meshed systems
	Phase configuration	Three-wire/three-phase
	Installation type	Overhead lines/cables
Capacity	Typical nominal capacity of DG	NA

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Legal Framework

The China Renewable Energy Law [58] went into effect on January 1, 2006, and was updated in 2009. The Renewable Energy Law has established five important rules, including the target of RE amount, the forced feed-in, the tariff classification, the cost-sharing, and the RE fund. Based on the five rules, China's policy framework to support RE development is basically formed. The central government develops the target RE amount and implements it through the national and provincial RE plans. The central government determines the feed-in tariff of RE. Then the grid corporation must totally purchase the feed-in electricity of RE at the feed-in tariff or at the biding electricity price, and the RE project should get the administrative license from or be filed by authority. The feed-in tariff is higher than the average tariff of conventional generation. The additional costs are covered by RE surcharges of electricity consumption around the whole country. In 2009, the Renewable Energy Law was amended to strengthen the coordination between the RE development plan and utilization and the strategy of national energy development, strengthen the effect of national plans on local plans, establish a protective regulation of totally purchasing RE electricity, and establish an RE development fund.

Technical Framework

It is the responsibility of the supply side to ensure the power quality, including technical parts (i.e., voltage quality) and non-technical parts (i.e., service quality). The power quality is essential for safe production and fruitful profit of the industry as well as people's living.

After a PV system is connected to the grid, the voltage bias of the PCC should meet the requirements of GB/T 12325 [59]. The voltage fluctuations and the flicker should meet the requirements of GB/T 12326 [60]. Table 22 shows the voltage fluctuation requirements after PV generation system connect to the grid.

Table 22: Requirements for Voltage Deviation in China's Distribution Grids According to GB/T 12326

r/(times/h)	d/%	
	LV/MV	HV
r≤1	4	3
1<r≤10	3*	2.5*
10<r≤100	2	1.5
100<r≤1000	1.25	1

Note:

1) The r represents the frequency of voltage change, which refers to the count of the voltage change per unit time (ascending or descending voltage changes counted once independently). Changes in several different directions, if the interval is less than 30 ms, should be counted once. The d represents the voltage changes, and its value is the voltage difference between the two adjacent extremes of the rms curve, expressed by nominal voltage of the system as a percentage.

2) For small changes in the frequency of r (less than once per day), the voltage change limits can be relaxed.

3) For random irregular voltage fluctuations, the mark "*" is labeled for its limits in the table.

Required Control Capabilities by Photovoltaic Systems

Active Power Control:

According to DL/T1040 [61], a PV power station should have the ability to participate in peak-load shifting and frequency regulating of the power system. PV power stations should be equipped with an active power control system, have the ability to smoothly adjust active power, and participate in active power control of whole system. An active power control system of a PV power station should be able to receive and automatically execute instructions of the active power as well as its change from the scheduling institute.

In power system failures or emergencies, a PV power station should be operated in accordance with the following requirements:

a) If the power system is broken down or runs in a special operating mode, the PV power station should reduce its active power in accordance with the requirement of the scheduling institute.

b) When the grid frequency is higher than 50.2 Hz, the PV power station should reduce its active power in accordance with the requirement of the scheduling institute, or be shut down in a severe case.

c) If the operation of the PV power station threatens the security and the stability of the power system, the PV power station should be shut down temporarily in accordance with the requirement of the scheduling institute.

When the troubleshooting is fixed and the power grid returns to normal operation, the PV power station should restore operation according to scheduled instruction.

Reactive Power Control:

PV systems should have the ability to regulate reactive power. The inverter should meet the requirement of dynamical adjustment within a range of lead 0.95 to lag 0.95 at rated power, i.e., the inverter can dynamically adjust within the rectangle in Figure 25 [62].

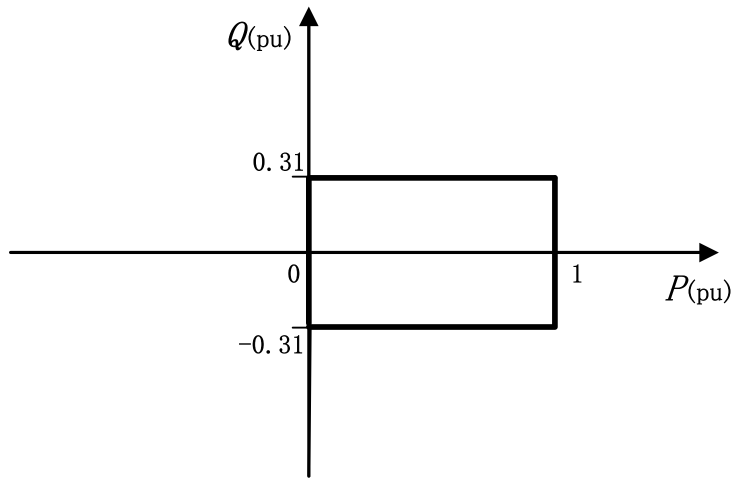


Figure 25: An inverter's reactive power range

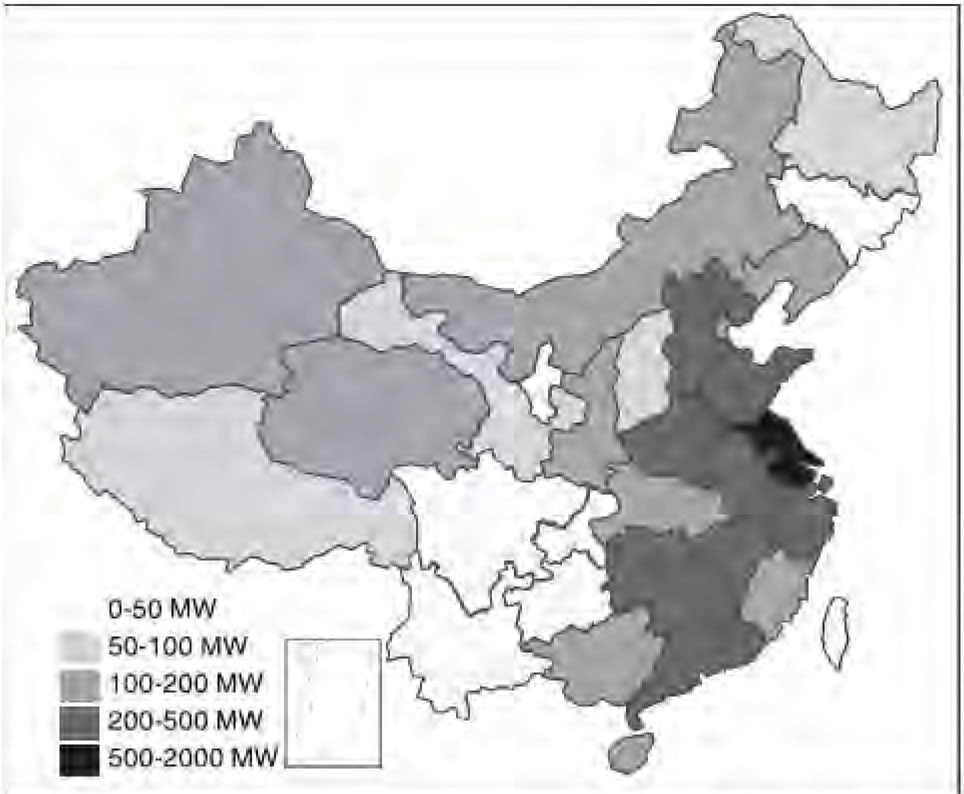
When the reactive power rating of the inverter does not meet the need of voltage regulation, it should install an appropriate reactive power compensation device in the PV power station. If necessary, a dynamic reactive power compensation device should be installed.

A PV power station connected at the 10-kV to 35-kV level should have the ability to adjust reactive power and participating voltage regulation according to the voltage of the PCC. The adjustment method, the reference voltage, and the voltage transfer slip should be set by the scheduling institute.

For a PV power station connected at 110 kV or above, a reactive power and voltage control system should be equipped. According to the instruction of the scheduling institute, a PV power station should automatically adjust its reactive power output or input and perform voltage control of PCC, and the adjusting speed and control precision should meet the requirements of the voltage regulation of the power system. When the utility grid's voltage is within the normal range, a PV power station connected to a 110-kV-level should be able to control the voltage of the PCC in the range of 97% to 107% of nominal voltage. A PV power station connected to a 220-kV-level or above should be able to control the voltage of the PCC in the range of 100% to 110% of nominal voltage.

Case Studies for High PV Penetration Scenarios

By the end of 2012, the total installed capacity of power generation in China was 1,145 million kw, of which installed PV capacity a totalled 8 GW, including distributed PV at 2.55 GW, accounting for 36.4% of the PV market share. In the new PV capacity in 2012, the capacity of distributed PV is 1.5 GW. China's distributed PV is growing rapidly and is mainly constructs on the rooftops of high energy–consuming plants, urban and rural buildings, and the utility facilities, such as the 6.68-MW grid-connected PV system on Hongqiao Station, the Beijing-Shanghai high-speed railway station; the Shanghai World Expo Theme Pavilion 3-MW grid-connected PV system; and the Zhejiang Yiwu International Trade City 1.295-MW grid-connected PV power stations. Since 2013, China has launched a number of distributed PV projects, including the high-tech industrial park Xiuzhou distributed solar PV power generation project phase (61 MW), the Tongxiang Economic Development Zone of distributed PV demonstration phase (15 MW), and the Haining tech zone distributed PV power generation project (20 MW). With the changes in China's policies, market-oriented distributed PV systems will become the mainstream of the PV market in 2015, and by 2020 the share of the distributed PV market will exceed 50%.



Province	Capacity MW/ Project Number	Province	Capacity MW/ Project Number	Province	Capacity MW/ Project Number	Province	Capacity MW/ Project Number
Anhui	230/28	Henan	329/50	Neimenggu	188/28	Tianjin	123/23
Beijing	247/30	Heilongjian	84/9	Ningxia	35/4	Xizang	60/7
Fujian	141/19	Hubei	131/13	Qianghai	101/27	Xinjiang	118/17
Gansu	100/10	Hunan	447/40	Shandong	487/57	Yunnan	30/8
Guangdong	494/67	Jilin	20/1	Shanxi	57/13	Zhejiang	456/67
Guangxi	119/9	Jiangsu	726/73	Shaanxi	137/22	Hebei	237/27
Hainan	198/10	Jiangxi	222/34	Shanghai	232/18	Liaoning	144/18
Sichuan	10/4	Chongqing	0/0	Guizhou	0/0	Total	5899/733

Figure 26: Golden-Sun demonstration projects in mainland China [63]

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

The "12th five-year plan of Chinese renewable energy" states that by 2015 China's target PV installed capacity is 10 GW and by 2020 solar capacity will reach 50 GW. However, as of the end of 2013, China's total installed PV capacity is about 16.5 GW, and the 2015 targets have been achieved in advance. It is predicted that the total installed PV capacity in China will reach 35 GW by 2015 and 100 GW by 2020.

In terms of incentives, the Chinese central government has introduced a number of PV power generation policies, including the "Golden Sun Demonstration Project" and "Building Integrated Photovoltaic Demonstration." Both are proposed for supporting distributed PV in a way of subsidizing the initial investment. In 2013, "the State Council on promoting the healthy development of the PV industry" was announced. Then several ministries introduced a number of policies and subsidies, including a feed-in tariff, subsidy of electricity price, subsidy management, project management, grid connection service, RE purchase, financial services, and other support, to prompt PV application. In August 2013, the National Development and Reform Commission issued notice to "promote the healthy development of the PV industry by price leverage" (NDRC Price No. 20131638), in which the nation is divided into three types of solar resource areas, clarified tariffs are RMB 0.9/kWh, RMB 0.95/kWh and RMB 1/kWh based on solar resources, and the feed-in tariff of distributed PV is RMB 0.42/kWh. However, there are several challenges on the road.

In terms of the grid, along with large-scale renewable energy access, some negative effects appear on grid security and stability. Therefore, to attain the large-scale application of renewable energy it is necessary to increase the RE absorptive capability of the grid, expand the grid and construct renewable energy simultaneously, and promote smart grid construction.

In terms of the market, the feed-in tariff of conventional generation in China is about RMB 0.35/kWh, and the electricity price of residence is about RMB 0.5/kWh, whereas the feed-in tariff of PV electricity is about RMB 0.92/kWh. PV electricity is still relatively expensive by comparison. Therefore, innovation is needed to continuously reduce the electricity cost of PV.

In terms of industry, the Chinese PV industry is undergoing a reorganization shuffle, and the industry environment is also gradually being standardized and more orderly. Under the new situation, the China PV industry will rely on technological progress and maintain the advantage in international competition.

Germany

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Table 23 shows relevant statistics on PV generation and power consumption in Germany.

Table 23: Statistics on PV Generation and Power Consumption in Germany

Statistic	Value	Year
Installed PV capacity (nationwide)	36.2 GW	Status: 03/2014 [64]
Peak load (nationwide)	80 GW	Status: 2011 [65]
Total generation capacity	132.7 GW	Status: 2011 [65]
Total energy generated by PV in 2012	28.000 GWh	Status: 2012 [66]
Share of PV on total energy consumption in 2012	≈ 5.7%	Status: 2012 [67]
Share of installed PV capacity connected to HV level	≈ 5.6%	Status: 06/2013 [68]
Share of installed PV capacity at HV/MV substations	≈ 1.1%	Status: 06/2013 [68]
Share of installed PV capacity connected to MV level	≈ 28.8%	Status: 06/2013 [68]
Share of installed PV capacity at MV/LV substations	≈ 2.8%	Status: 06/2013 [68]
Share of installed PV capacity connected to LV level	≈ 61.7%	Status: 06/2013 [68]
Average size of PV system	≈ 17 kWp	Status: 2012

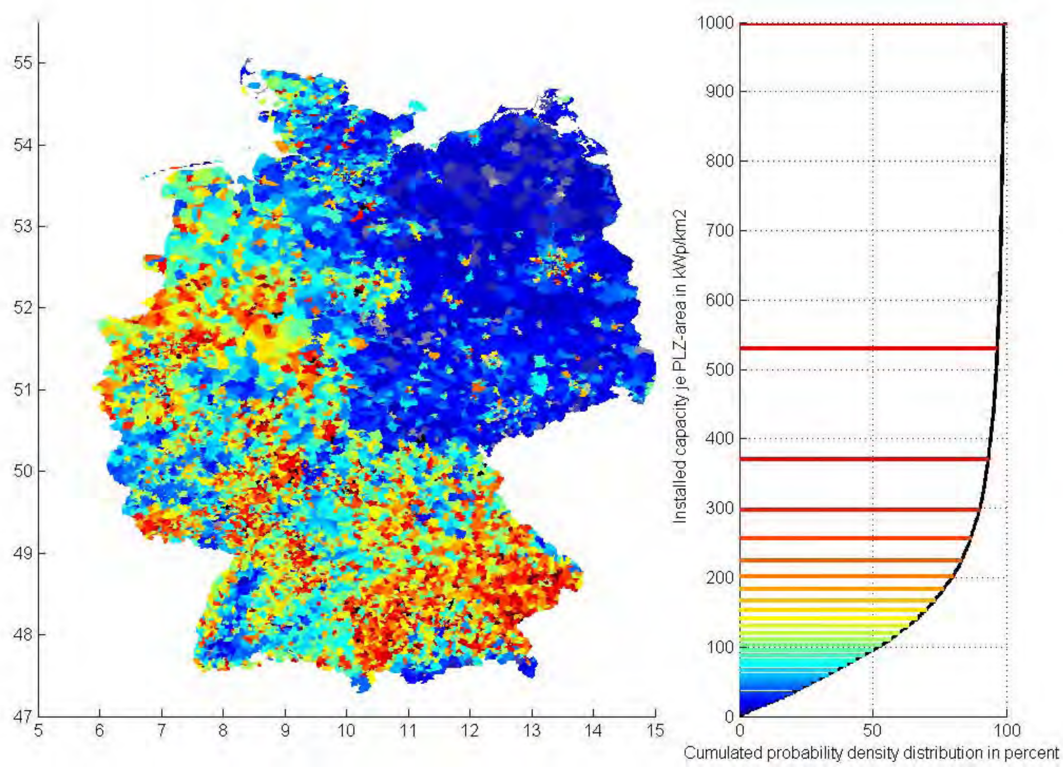

Figure 27: Installed PV capacity per ZIP-code area (status 05/2013). Figure by Y.M. Saint-Drenan, Fraunhofer IWES

The National Distribution Grid Structure

The German distribution grid covers MV, LV, and parts of the HV level. A general overview about the German distribution grid structure is given by Figure 28.

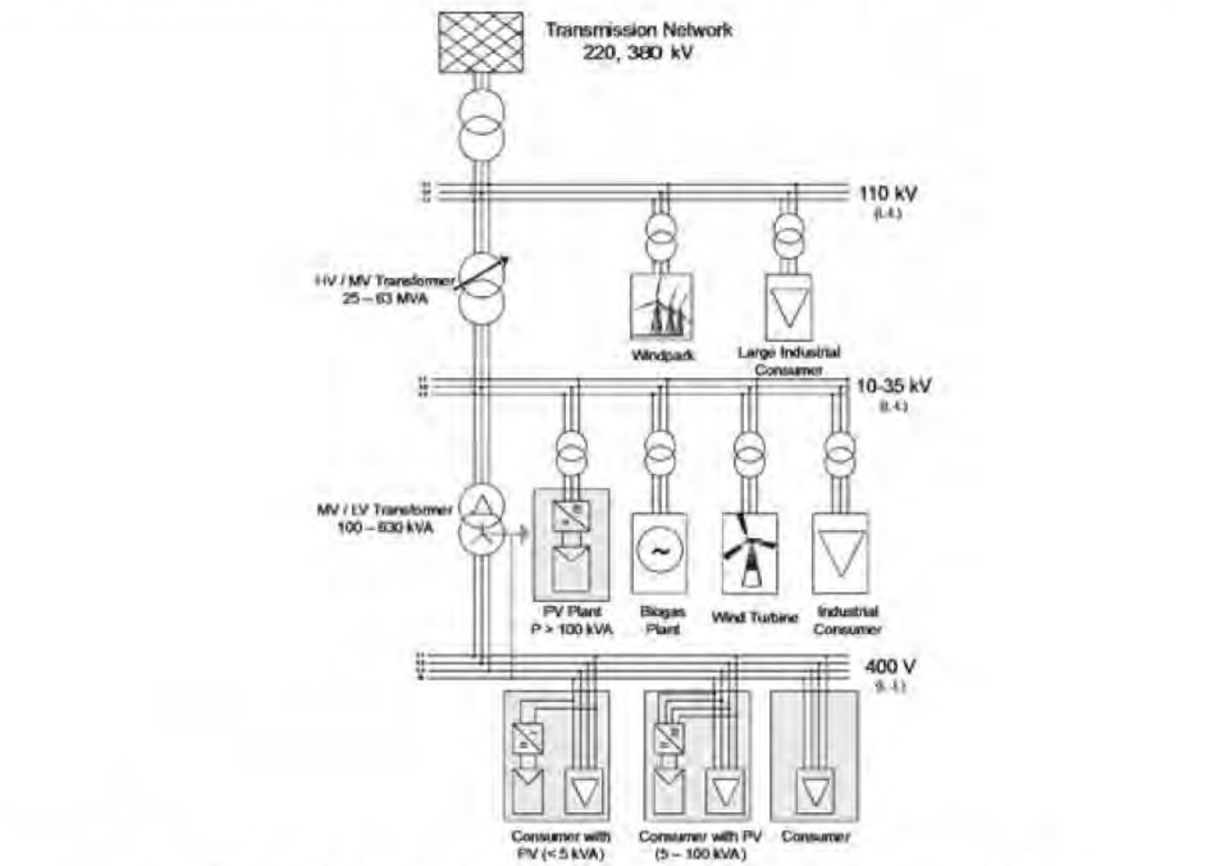

Figure 28: General structure of the German distribution system [70]

HV Level: The nominal line-to-line voltage at the HV level is 110 kV. During normal operation, the voltage has to be maintained between 100 kV and 123 kV. For short-time operation, a voltage bandwidth from 96 kV to 127 kV is allowed [69].The HV level is realized as a three-phase delta system consisting mostly of overhead lines. In suburban areas, HV underground cables also exist. The preferred system topology is meshed. Interconnection customers are mostly DSOs, very large industrial facilities, and multi-MW generation plants (conventional power plants, wind farms, etc.).

Power System Management: Manned master substations monitor and control the steady state of the HV system via SCADA systems. They are authorized to switch circuit breakers and disconnectors at the HV level (remote control). The power system management at the HV level often comprises visualization and optimization techniques, such as loading analysis, state-estimation, short-circuit calculation, and GIS. Master substations permanently exchange information with parallel master substations of other service areas. Controllers of PV plants are typically peer-to-peer connected to the master substation for remote-control purposes in cases of disturbed grid operation. Current technical trends at the HV level are wide-area monitoring via phasor measurement units (PMUs), temperature monitoring of overhead lines, and load monitoring with automatic n-1 calculations to fully utilizing the reserve capacities of conductors during normal operation.[6]

Controllable Equipment:

+ Remote-controlled SVC and STATCOMS for reactive power compensation
+ Autonomous and manual (remote) tap settings at the substation transformer
+ Automatic and manual (remote) grid topology reconfigurations
+ Reactive power control of DG within specified limitations, according to [74] (see also 0)
+ Active power control of DG during disturbed grid operation, according to [74] and the German EEG.

Major Technical Barriers for PV Interconnection: Major technical barriers for PV interconnection at the HV level are typically transmission capacities at the HV level and substations. However, currently only 5.6% of the total installed PV capacity is connected directly to the HV level (in total about 1.8 GWp).

Table 24: Basic Information on HV Level

Basic Technical Guideline: Transmission Code 2007 [72]		
Voltage	Nominal line-to-line voltage	110 kV
	Voltage range normal operation	100 kV/123 kV
	Voltage range transient fluctuations	96 kV/127 kV
Grid Layout	System topology	Mostly meshed
	Phase configuration	Three-wire/three-phase
	Installation type	Overhead lines/cables
	Typical range of feeder length	100 km – 500 km [85]
Load and Generation	Load-carrying capacity of a single three-phase system	10 km -100 MW per line [85]
	Typical nominal capacity of DG	Multi-MW PV system[7]
	Typical customer	Large industrial facilities, DSOs

[6] See E.ON Netz demonstration line segments „Flensburg-Niebüll“ and „Flensburg-Breklum“. Reference: http://www.forum-netzintegration.de/uploads/media/20120918_Jansen_KreisNF.pdf
[7] E.g., PV plant Perleberg, 35 MWp, Brandenburg

MV Level: The rated capacity of HV/MV transformers is usually between 25 MVA and 63 MVA. The preferred nominal line-to-line voltage at the MV level is 20 kV ±10% (requirements defined by EN50160). In suburban areas also, 10-kV systems can be found. Some few supply grids are operating with a nominal voltage of up to 35 kV. The MV level is realized as a three-phase delta system consisting mostly of overhead lines in rural areas and underground cables in suburban areas. In cases of grid reinforcement and/or expansions, underground cables are preferred. Meshed system topologies can be found in urban areas. In suburban and rural areas, often a mixture of open and closed-loop structures exist. In some rural areas, pure branch-feeder configurations can be found. Typical interconnection customers are large industrial facilities as well as utility-scale generation units with a rated capacity of up to some MW.

Power System Management: DSOs, responsible for MV system operation, are authorized to switch circuit breakers and disconnectors at the MV level only (remote control). SCADA systems monitor voltages and power flows at selected crucial MV nodes (e.g., transformer substations, switching substations). Current technical trends are the incorporation of MV state-estimation for monitoring purposes and expert systems for sending active and reactive power set values to PV plant controllers.

Controllable Equipment:

+ Autonomous and manual (remote) tap settings of the transformation ratio at the substation transformer
+ Manual (remote) grid topology reconfigurations
+ Reactive power control of DG within specified limits, according to [74] (see also 0)
+ Active power control of DG in disturbed grid operation, according to [74] and the German Renewable Energy Sources Act EEG 2012 §6, §11 (see also 0).

Major Technical Barriers for PV Interconnection: Currently, about 28.7% of Germany's total PV capacity is directly connected to the MV grid and 1.1% to HV/MV substations (in total about 10.4 GWp). Over-voltages and over-loadings of conductors and transformers are the major technical barriers for PV interconnection, especially in rural areas. Traditional grid reinforcements are the preferred solution to increase the hosting capacity for PV at the MV level.

Table 25: Basic Information on the MV Level

Basic Technical Guidelines: Distribution Code 2007 [73], Technical Guideline for the Connection and Parallel Operation of Generators Connected to the MV Network [74]		
Voltage	Nominal line-to-line voltage	10 kV/20 kV/30 kV
	Voltage range normal operation	±10% $V_{N,LL}$ (EN50160)
	Permissible voltage rise by feed-in (normal operation)	$\Delta V_{max} \leq 2\%$ [74]
Grid Layout	System topology	Radial and meshed systems
	Phase configuration	Three-wire/three-phase
	Installation type	Overhead lines/cables
	Typical range of feeder length	1 km – 20 km [85]
Load and Generation	Load-carrying capacity of a single three-phase system	1 MW – 10 MW per line [85]
	Typical nominal capacity of DG	0.25 – 3 MW
	Typical customer	Medium industrial facilities, rural supply

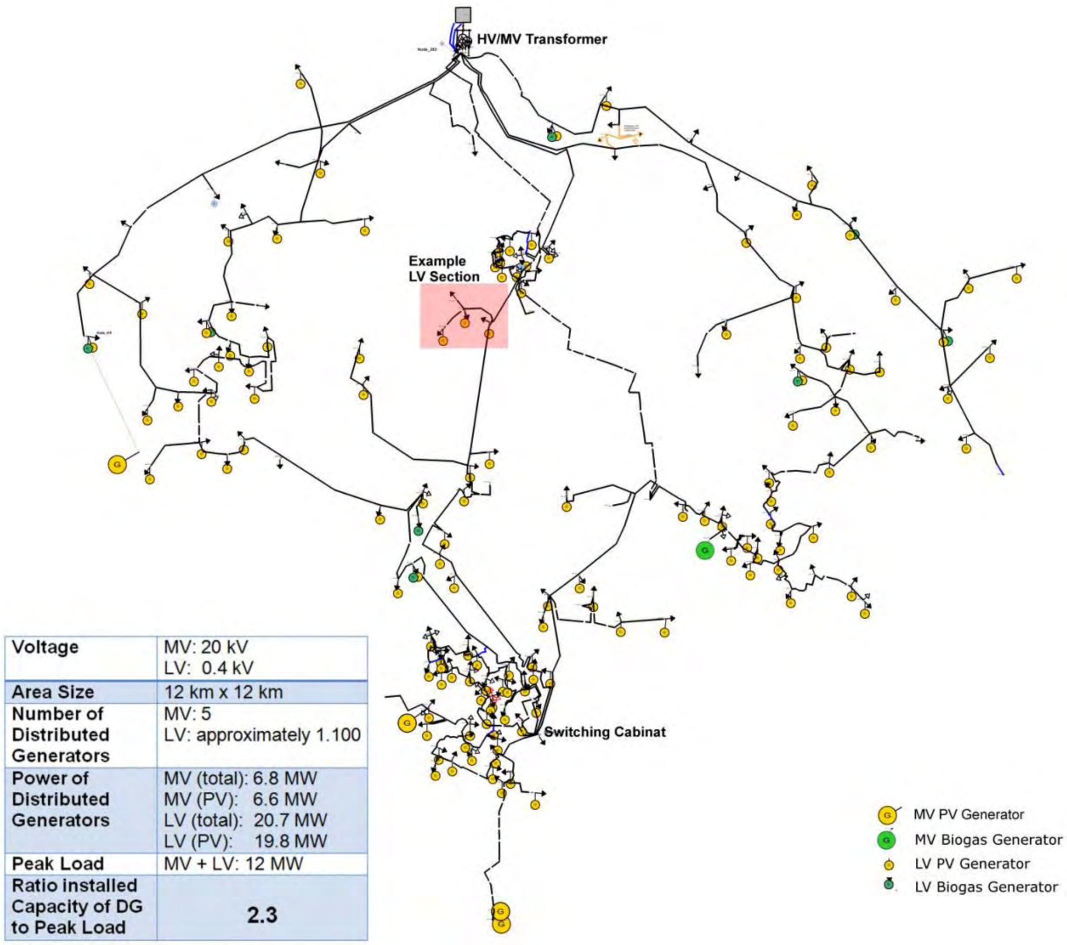

Figure 29: Example of a real German MV grid with high PV penetration

LV Level: Delta-star transformers with a rated capacity of typically 100 kVA to 630 kVA are used for the link between MV and LV levels. In grid sections with high local PV penetration, transformer ratings of more than 630 kVA are also possible. The nominal line-to-line voltage at LV levels is 400 V ±10% (requirements defined by EN50160). The system is realized as a three-phase star system with mostly underground cables comprising a neutral conductor. In some rural areas, overhead lines still can be found. Most of the LV grids consist of branch feeders only. For earthing TN-C-S systems, as defined by IEC 60364-1, are most common. Typical interconnection customers are private households and small commercial buildings. Most of the German PV capacity can be found at LV levels (70% of the total PV capacity [68]).

Power System Management: Typically, no active monitoring and control are applied. Current development trends are LV state-estimation and on-load tap changers for MV/LV transformers.

Controllable Equipment:

+ Manual (not remote) topology reconfigurations at switching cabinets
+ Manual (not remote) transformer ratio settings of MV/LV transformers (usually not equipped with on-load tap changers for voltage control)
+ Autonomous reactive power control of DG within specified limits, according to [75]
+ Remote active power control of DG during disturbed grid operation or a general active power curtailment of small DG (<30 kWp) according to [75] and the German Renewable Energy Sources Act EEG 2012 §6, §11 (see also 0)

Major Technical Barriers for PV Interconnection: Over-voltages are the major technical barrier for PV interconnection, especially in rural areas. Traditional grid reinforcements are the preferred solution to increase the hosting capacity for PV at the LV level.

Table 26: Basic Information on the LV Level

Basic Technical Guideline: Technical Guideline for the Connection and Parallel Operation of Generators Connected to the LV Network [75]		
Voltage	Nominal line-to-line voltage Voltage range normal operation Permissible voltage rise by feed-in (normal operation	0.4 kV ±10% $V_{N,LL}$ (EN50160) $\Delta V_{max} \leq 3\%$ [75]
Grid Layout	System topology Phase configuration Installation type Typical range of feeder length	Mostly radial, in urban areas also meshed systems Five-wire/three-phase Mostly cables 100 m – 500 m [85]
Load and Generation	Load-carrying capacity of a single three-phase system Typical nominal capacity of DG Typical customer	1 MW per MV/LV substation [85] 10 kW (PV on households) small industrial facilities, households

Figure 30 gives an example of a real German LV grid with high PV penetration.

Voltage	LV: 0.4 kV
Area Size	1.6 km x 1.7 km
Number of Distributed Generators	44 (PV)
Power of Distributed Generators	0.71 MW (PV)
Peak Load	0,25 MW
Ratio installed Capacity of DG to Peak Load	**2.8**

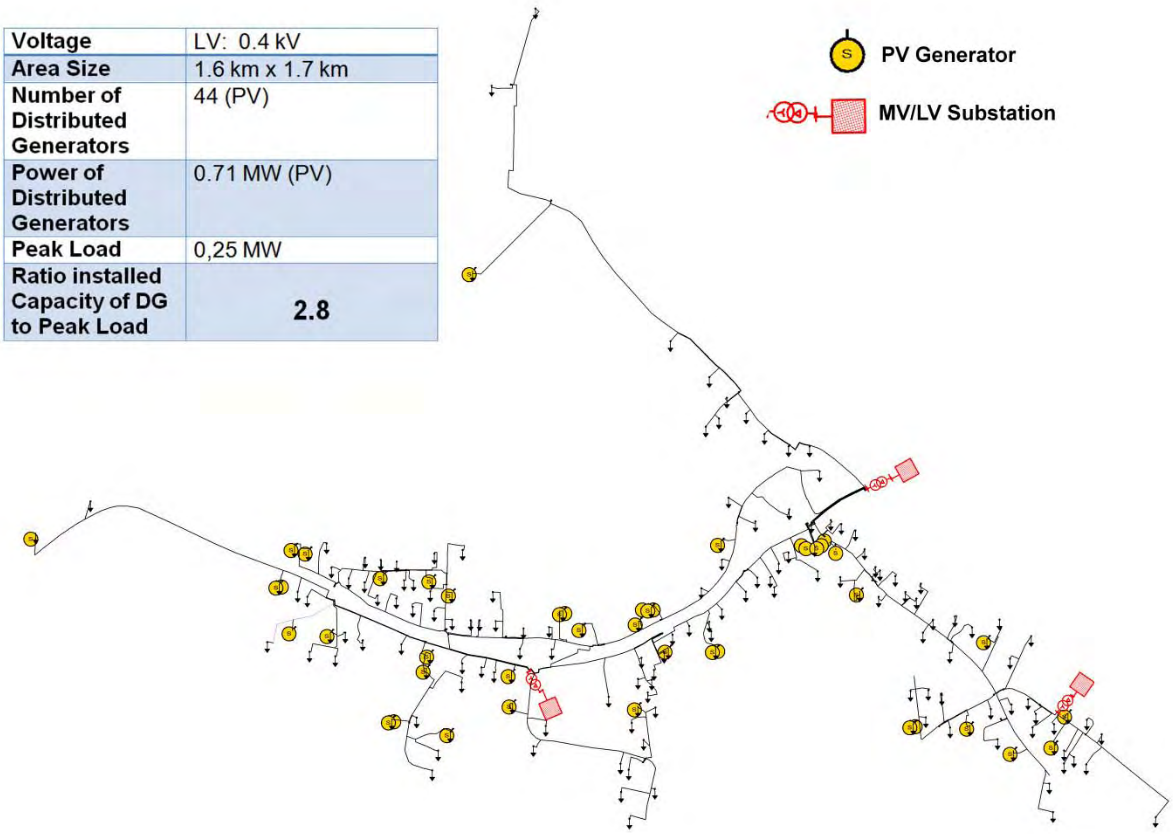

Figure 30: Example of a real German LV grid with high PV penetration. The system topology is radial.

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Legal Framework

According to §5 EEG, "German Renewable Energy Sources Act," DSOs are obliged to interconnect renewable energy–based distributed generators with their grid at a point of common coupling that has the shortest air-line distance to the site of the generator. For DGs with up to 30 kW installed capacity, the existing PCC of the property is automatically considered to be an appropriate point of interconnection (POI). The costs for the interconnection of the DGs have to be borne by the plant operator, §13 EEG. The DSO has to cover any additional costs for the interconnection, if at a different POI than that defined by §5 EEG is chosen by the DSO §13 (2) EEG. If the DG capacity cannot be interconnected due to technical reasons, the DSOs are obliged to conduct necessary grid reinforcement measures immediately according to §9 EEG. According to §14 EEG, the costs for these reinforcement measures have to be borne by the DSO itself. The DSO is released from this duty if the costs for the necessary reinforcement measures are economically unreasonable §9 (3) EEG. As of today, this case has not yet been specified in more detailed and is considered to be highly case sensitive.

Technical Framework

The quality of the electrical supply in Germany is defined by the service reliability, the voltage quality, and the service quality. As of today, maintaining the voltage quality is the major issue when planning the interconnection of PV to the distribution grid.

The EN 50160 standard defines the required voltage quality for MV and LV customers during normal grid operation in Germany. For the interconnection of PV systems especially, the criteria for slow and fast voltage deviations have to be considered during the interconnection planning process. Table 27 lists the requirements according to the EN 50160.

Table 27: Requirements for Voltage Deviation in German Distribution Grids According to EN 50160

Criterion	MV Level	LV Level	Reference Value	Evaluation Period	Required Values within Bandwidth
Slow Voltage Deviations	U_N ± 10%	U_N ± 10%	10 min RMS	1 Week	99% (MV) 95% (LV)
Fast Voltage Deviations	4% – 6% U_N	5% – 10% U_N	10 ms RMS	1 Day	100%

Required Control Capabilities by Photovoltaic Systems

PV systems that are to be connected to the mains need to provide certain control capabilities that are defined by the German MV and LV guidelines for the interconnection of DG [74], [75] (for more information on the German grid code requirements compare subtask 4) and the German Renewable Energy Sources Act. The following abridgement focuses on active and reactive power control capabilities of PV systems, which are considered to support the quasi-static distribution grid operation.

Active Power Control:

The requirements for active power curtailment for PV systems in Germany are currently defined by §6 EEG. Depending on the installed module capacity of the PV system, the following control capabilities have to be provided:

Table 28: Requirements for Active Power Curtailment for PV Systems

System Size	Requirements	Required Until	Reference
$P_N \geq 100$ kWp	Remote control interface for DSO	06/30/2012	§6 and §66 EEG 2012
30 kWp $\leq P_N < 100$ kWp	Remote control interface for DSO	31/12/2013	§6 and §66 EEG 2012
$P_N < 30$ kWp	Choice between remote control interface for DSO or permanent feed-in limitation to 70% PN	31/12/2013	§6 and §66 EEG 2012

Although there has not yet been any uniform standard for the realization of the remote control interface, most of the German DSOs use long-wave radio ripple control systems for sending set values to the inverters.

Reactive Power Control:

Depending on the installed module capacity, PV systems have to provide a certain amount of reactive power if demanded to do by the DSO. Table 29 lists the current requirements according to the German MV and LV guidelines [74], [75].

Table 29: Requirements for Reactive Power Control for PV Systems

Voltage Level	System Size	Technical Requirements	Required Until	Reference
MV	Any size	Minimum power factor of 0.95 (leading/lagging)	04/01/2011	[74] [77]
LV	$S_N < 3.68$ kVA	No requirements	-	[75]
	3.68 kVA $\leq S_N \leq$ 13.8 kVA	Minimum power factor of 0.95 (leading/lagging) if $P(t) \geq 20\% \, S_N$	01/01/2012	
	$S_N > 13.8$ kVA	Minimum power factor of 0.9 (leading/lagging) if $P(t) \geq 20\% \, S_N$	01/01/2012	

As of today, there is no uniform method for the provision of reactive power. For PV systems connected to the MV level, the provision of reactive power can be either realized autonomously (e.g., fixed preset power factor or voltage-dependent reactive power provision Q(U)) or via remote control. For PV systems connected to the LV grid, only autonomous (without communication link to DSO) reactive power provision methods are used.

Chapter 0, best-practice approaches for determining the hosting capacity of certain grid sections by taking into account the technical constraints of the grid operation as well as the grid-supporting effects of active and reactive power control by inverters are introduced.

Case Studies for High PV Penetration Scenarios

The German Energy Agency (dena) estimated the investment costs for grid reinforcement in the German distribution grids of €28 to €42 billion until 2030 [86]. The basic reason for the grid reinforcement measures is the grid integration of additional DG capacity. Also the cost-reducing potential of new technical options are investigated in [86]. As a result, new technical options such as MV/LV transformers with OLTC, reactive power control of DGs, and high-temperature conductors can achieve a cost reduction potential[8] of up to 50% compared to the status quo [86]. These values give a rough estimation of investment costs and cost-reduction potential by introducing new technical solutions in the German distribution grid.

Cost-Benefit Analysis of Autonomous Voltage Control Strategies Applied in the LV Grids

Detailed cost-benefit analyses are carried out for specific LV and MV grid sections in [81], [84], [87], [88]. The cost-benefit analysis of [84] compares different autonomously operating voltages control strategies provided by PV inverters and MV/LV transformer with OLTC for two real LV grids. A steady PV expansion over 10 years is assumed. Figure 31 shows the resulting net present value (NPV) by applying different voltage control strategies. Detailed information on the applied control strategies are listed in Table 50, and the configuration of the Q(V) and P(V) characteristic is given in Figure 78 in the appendix.

The biggest savings potentials result from deferring grid reinforcement measures to future points in time by applying *and* considering the technical potential of autonomous voltage control strategies already in PV interconnection studies. In LV grid No. 20, for example, the highest savings potential can be found for the Q(V)/P(V) control, with a saving of approximately 75% compared to the no-voltage-control scenario (reference scenario). In LV grid No. 39, the MV/LV transformer with OLTC reaches the highest savings potential, with a savings of approximately 50% compared to the no-voltage-control scenario.

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[8] The reduction potential is determined by exemplary grid calculations; additional operational costs (e.g., grid losses, maintenance costs) are not considered in the calculations.

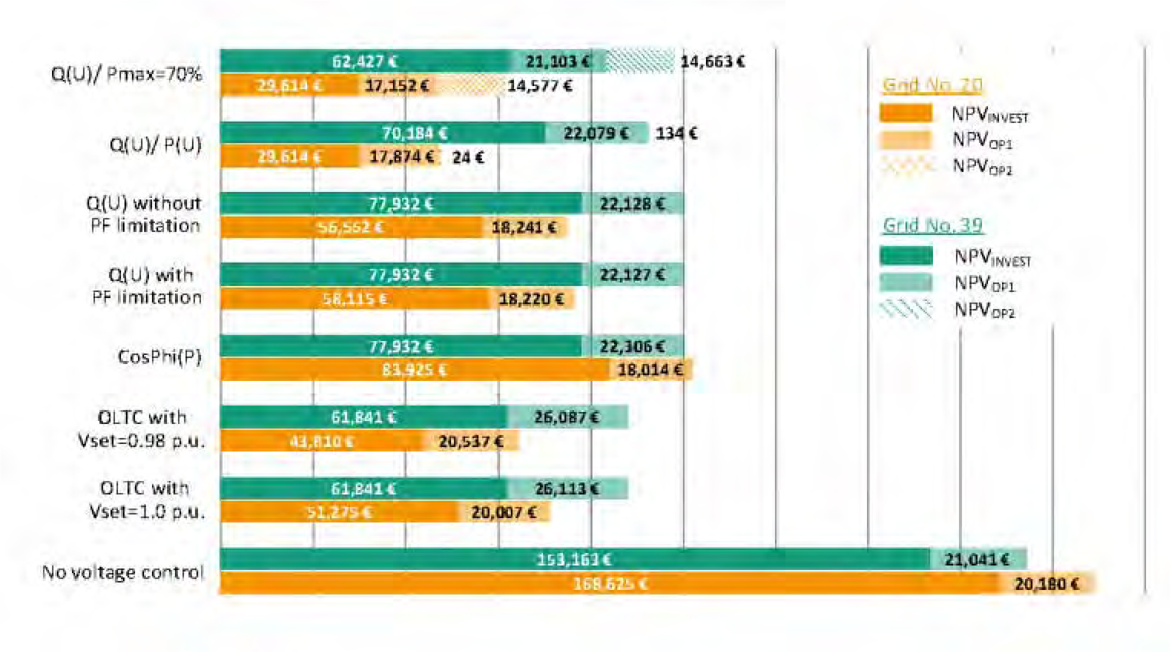

Figure 31: Total net present value (NPV) of investigated local voltage control strategies referred to the beginning of year t1. NPV_{Invest}: Grid reinforcement, NPV_{OP1}: Network losses + maintenance, NPV_{OP2}: reduced PV feed-in [84]

Parallel Operation of Autonomous Voltage Control Strategies Provided by PV Inverters and Distribution Transformers

Although investigations in [81], [84], and [87] clearly highlight the economic benefit of applying autonomous voltage control strategies provided by PV inverters, concerns regarding possible unintended interferences with other controllable devices (e.g., autonomously operating MV/LV on-load tap changers) may arise.

In [90], [91] possible interactions of autonomous voltage control strategies of PV inverters and distribution transformers are investigated. The simulations are performed based on a real German MV grid (compare Figure 29) with very high PV penetration (installed PV capacity exceeds the winter peak load by 2.3 times). For the simulations, data from nine geographically distributed solar irradiation measurement units are used to ensure a realistic representation of the power fluctuations within the investigated MV grid. Table 30 shows the investigated control strategies of the HV/MV transformer and PV inverters during parallel operation. The simulations are performed for two characteristic summer days (a clear-sky day and a partly cloudy day with alternating solar irradiation).

Table 30: Investigated Control Strategies of the HV/MV Voltage Transformer and PV Inverters in [90]

HV/MV transformer control	PV inverter control (MV level)
Fix voltage set point at the MV bus bar in the substation	Fix power factor of 1.0 (mode 1)
	Fix power factor of 0.95 (mode 2)
Power flow dependent voltage set point at MV bus bar in the substation	Cosφ(P) characteristic (mode 3)
	Q(V) characteristic (mode 4)
** Mode 4 but with different slack-bus voltage. Shows sensitivity of Q(V) strategy on different voltage magnitudes.*	

Figure 32 (left) compares the measured and simulated active and reactive power flow over the HV/MV transformer for the summer day with alternating solar irradiation. In Figure 32 (right), a reactive power ramp rate sensitivity analysis at the HV/MV transformer is performed for different autonomous voltage control strategies (provision of reactive power) of the PV inverters for the same day. The reactive power control of PV inverters leads to an increase of reactive power fluctuations in the grid, especially on days with alternating solar irradiation. This effect can cause an increase of voltage variations at the MV bus bar in the substation, which is the control variable of the HV/MV transformer OLTC.

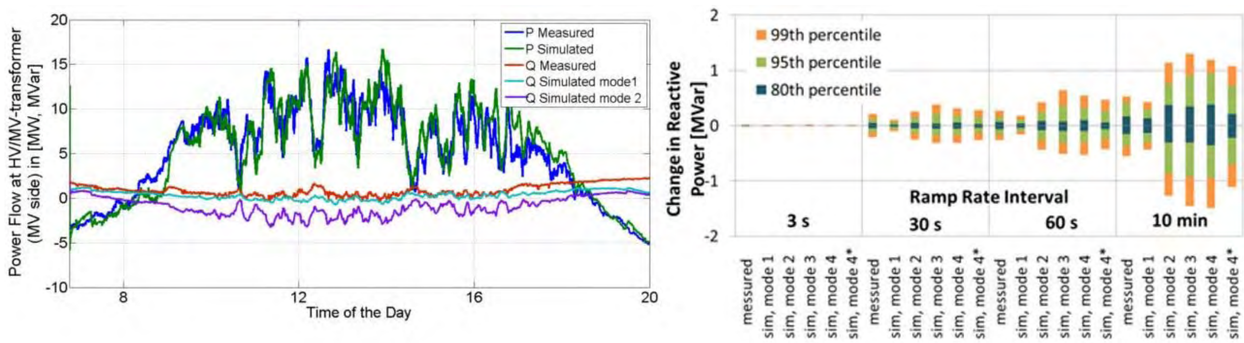

Figure 32: Measured and simulated power flow at a HV/MV substation (left) and reactive power fluctuations at a HV/MV substation for different local control strategies of PV inverters (right) on a summer day with alternating solar irradiation [90]

In [91], the parallel operation of a PV inverter and transformer control is evaluated in the number of transformer tap changes and the maximum MV grid voltage. The impact of reactive power control of the PV inverters on the number of transformer tap changes differs significantly between the investigated control strategies.

- The power flow–dependent control of the HV/MV transformer improves the voltage control in the grid but also leads to an increase of transformer tap changes compared to the transformer control with a fixed voltage set point.
- Reactive power control of PV inverters lead to increased reactive power fluctuations over the MV/HV transformer impedance and hence can trigger additional tap changes during parallel operation compared to the OLTC controlled to a fixed voltage set point.

- Reactive power control of PV inverters decreases the number of transformer tap changes during parallel operation with a power flow–dependent OLTC control.
- The voltage dependencies of the Q(V) characteristic have a damping effect on the voltage step caused by the changes of transformer tap settings.

Further optimization potential in parallel operation of PV inverter and distribution transformer control is investigated and discussed in [91].

Reactive Power Flow Optimization by Using the Reactive Power Control Capabilities of Utility-Scale PV Systems at the MV Level Within the Context of a Central Control Strategy

Using autonomous voltage control strategies can significantly improve the hosting capacity of distribution grids for further PV deployment. However, the reactive power provision by PV inverters may increase the reactive power exchange (Q-Exchange) between the HV-and MV-Level, which in turn can lead to additional operational costs for the DSO (penalties for exceeding predefined power factor limitations). To minimize the effect of additional LV reactive power consumption (by PV inverters to limit local voltage raises), DGs within the MV-grid and the HV/MV transformer can be centrally controlled to compensate/minimize the Q-Exchange with the upstream grid. This central control approach has been investigated based on a real German distribution grid with very high PV penetration (compare Figure 29) in [92]. The goal of this central control is to minimize the Q-Exchange between the HV-and MV-level while keeping the power factor of the MV PV-inverters ($\cos\varphi_{min}$=0.9) and voltage in the MV-Grid (U_{max}=1.06pu, U_{min}=0.96pu) within specified limits.

Figure 36 shows the Q-Exchange without (original) and with central control (linear optimization, LinOpt) for a summer day with a clear sky and for different power factors of the downstream LV PV inverters. The results highlight the technical potential of the reactive power capabilities of MV PV inverters to compensate reactive power flows and hence minimize the Q-Exchange between the HV and MV levesl. Lower power factors of PV inverters at the LV level lead to a higher inductive Q-consumption of the total distribution grid (that is MV + LV level). The central control approach can significantly reduce this inductive Q-Consumption (LinOpt, pink) by using the reactive power capabilities of the MV PV inverter for compensation purposes. Even in a worst-case scenario ($\cos\varphi$=0.95 provided by LV PV-inverter), this combined central and local control strategy would show a significant technical potential by reducing the Q-Exchange with the upstream grid by about 40%.

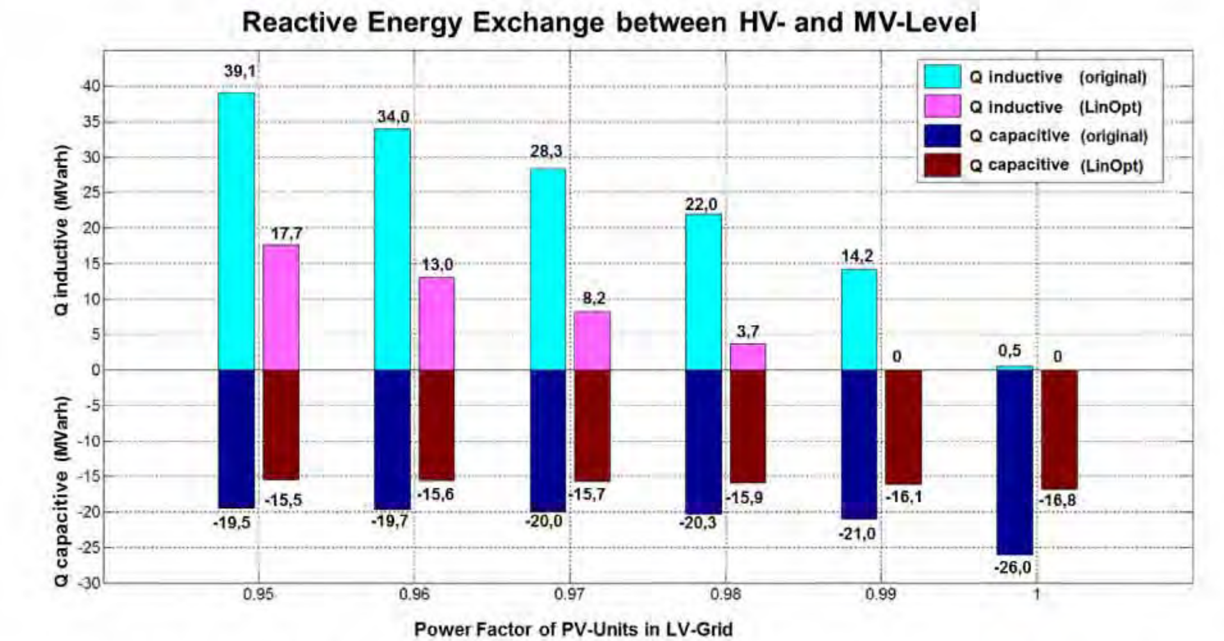

Figure 33: Influence on Q-Exchange by changing power factor of LV PV units and optimization potential by applying the central control strategy on a summer day with a clear sky [92]

However, using MV PV inverters for reactive power compensation is only an alternative measure to conventional alternatives, such as capacitor banks, for example. Cost-benefit analyses need to be carried out to also assess the economic potential of such a central control approach. In [93], a cost-benefit analysis for a central control approach is performed. Figure 34 shows the annual active and reactive power flow at the TSO interconnection point with and without the central control approach. For the cost-benefit analysis, three different PQ-bands at the TSO interconnection point are specified, where PQ-band 0 represents a worst-case scenario for the control approach and PQ-band 2 can be considered the most realistic one. For reactive power values out of the specified PQ-bands, the DSOs would have to pay a penitent fee to the TSO. The central control reduces the Q-Exchange at the TSO connection point and hence lowers the penitent fee payment [93].

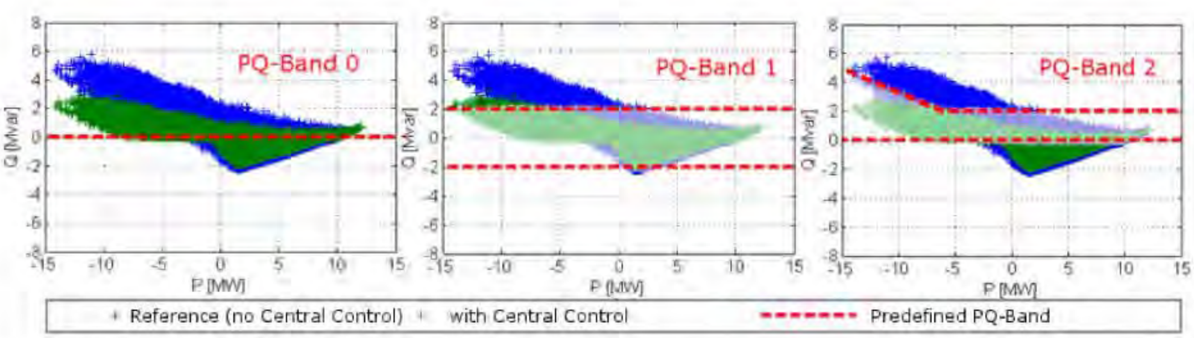

Figure 34: Results of the annual active and reactive power flow (1/4-hour mean values) at the TSO connection point with central control (green crosses) and without central control (blue crosses) for a cosϕ of 0.95 of the LV PV units [93]

For the simulations, the central controller was assumed to rely on complete information about the actual grid status. For real applications, this information would be limited to grid nodes with measuring devices. Figure 35 shows the annuity of the required investments for the central control plus operational costs (i.e., grid losses, Q penalties) in relation to the amount of required measuring devices. The results show that the central control approach could be cost competitive if the number of required measuring devices is low (≤10).

Nevertheless, the central control approach has additional benefits for the DSO, which are not explicitly considered in the presented analysis. In addition to reactive power consumption for voltage support, coordinated active power control for an improved congestion management and a detailed monitoring of the grid could be considered benefits. Allocating the investment costs for the measurement devices on the different ancillary services will further improve the economic benefit of the proposed control approach.

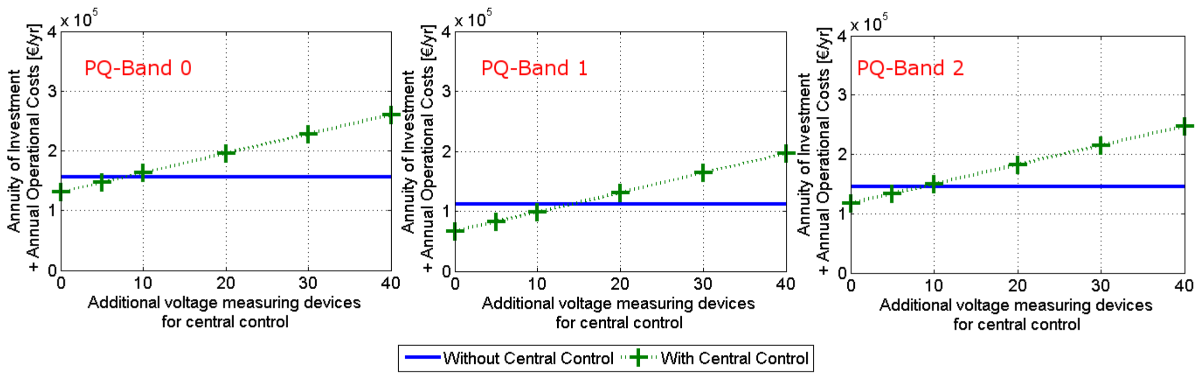

Figure 35: Annuity of investment plus annual operational costs for the scenario with a power factor of 0.95 (lagging) of the LV PV systems and for different PQ-bands at the connection point to the TSO [93]

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

As of today, the German Renewable Energy Sources Act (EEG) guaranties priority feed-in for renewable energy resources and a fixed feed-in tariff over 20 years for the system owner. The feed-in tariff for PV systems decreased significantly during the last few months, so that the number of new PV installations in Germany is also declining. The current feed-in tariff (status 07/2013) of a residential-scale PV system (10 kWp to 40 kWp) is 17.78 € cent/ kWh [1]. It is planned that the feed-in tariff system will be ceased after an installed PV capacity of 52 GWp is reached (EEG 2012 §20b 9a). This will shift the major source of income for PV plant operators from pure grid feed-in toward solutions for improved energy self-consumption and market-related DG operation (e.g., in the context of virtual power plants). In cases of improved self-consumption, it is likely that the average PV system size is declining (17 kWp in 2011).

Further developments of the EEG and the German Energy Act (EnWG) are currently under discussion. The smart grid roadmap of the *German Association of Energy and Water Industries* [89] gives an overview on necessary regulatory changes in Germany. Important points related to PV systems are the:

- Installation of an information network for energy consumption, energy production, and grid conditions with access for all relevant stakeholders;
- Development of regulatory framework and technical standards based on market and grid aspects that enable an intelligent control of loads, storages, and DGs by the DSO or other relevant stakeholders in the distribution grid;
- Installation of markets and/or new network access requirements that enable further ancillary services by DG systems.

Greece

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New PV grid-connected capacity increased rapidly over the past few years in Greece. The new capacity for the year 2010 was 150 MWp, and for the year 2011 it was 400 MWp. In the year 2012, due to the gradual maturity of many PV projects and the attractive feed-in tariffs, and despite the economic situation, the annual PV installation capacity reached its peak of 912 MWp. For 2013, despite the economic crisis, the momentum due to the attractive feed-in tariff contracts that certain developers were still holding is expected to boost the annual installed capacity to more than 1,000 MWp. The development of the annual and cumulative PV capacity is presented in Figure 36. In the meantime, the Greek government, under the pressure of the burgeoning renewable energy fund deficit, is planning to further reduce the feed-in tariffs (possibly retroactively), while it has already imposed a temporary (until July 2014) special tax on revenues on PV electricity generation plants in Greece for PV plants connected to the grid in 2013 and before. Further, the increasing penetration of PV systems should also push the authorities to study, plan, and adopt technical and regulatory measures to allow higher penetrations of renewables in the future.

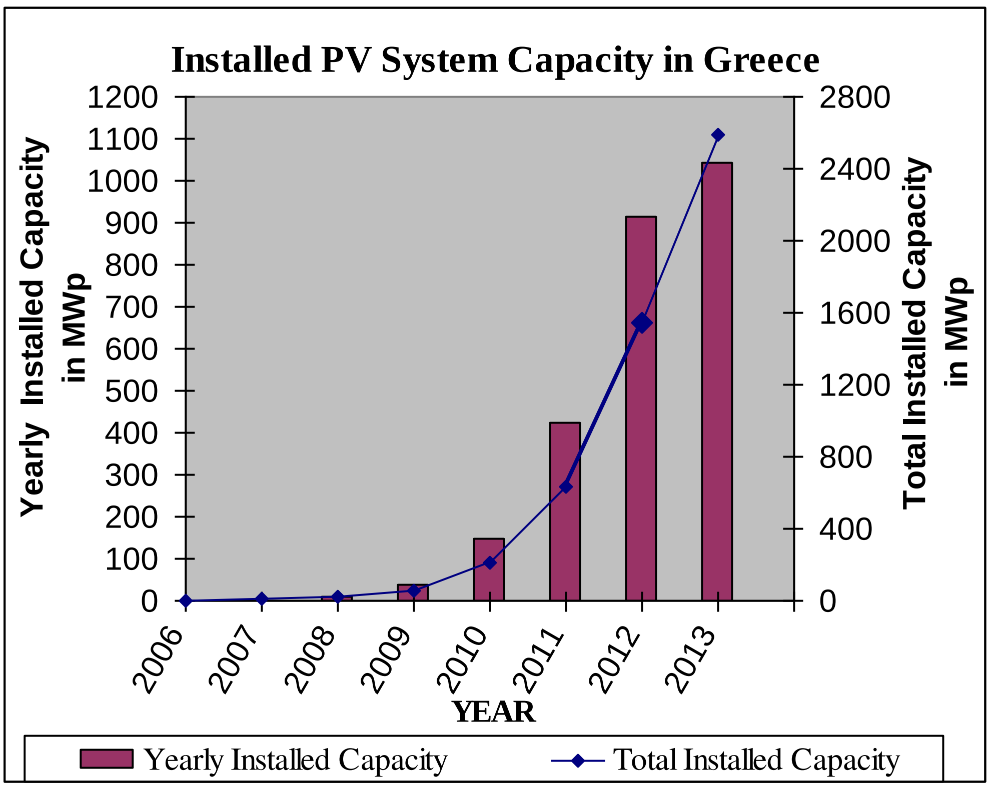


Figure 36: Annual and cumulative installed PV capacity in Greece.

Table 31: Statistics on PV Generation and Power Consumption in Greece.

Statistic	Value
Installed PV capacity nationwide, 10/2013	2.564 GWp
Installed PV capacity (interconnected system), 10/2013	2.428 GWp
Peak load (interconnected system, 2012)	9.894 GW
Total energy consumption in 2012 (interconnected system)	50.558 GWh
Total energy generated by PV in 2012 (interconnected system)	1487.8 GWh
Share of generated PV electricity to energy consumption (interconnected system), 2012	2,94%
Share of installed PV capacity connected to HV level, 2012	1,17%
Share of installed PV capacity connected to MV level, 2012	39,66%
Share of installed PV capacity connected to LV level, 2012	59,17%
Installed PV capacity nationwide, 10/2013	2.564 GWp
Installed PV capacity (interconnected system), 10/2013	2.428 GWp

As shown in Table 31, all the PV installed capacity is connected to the low and MV grid, and, up to now, the PV-generated electricity is experienced by the system operator as a negative load. This can be tolerated without any negative effects when the instant power penetration level is relatively low and does not create any operation- and security-related problems. Because there are already locations in the distribution grid where the local penetration has increased significantly, measures are being taken at the moment to limit new capacity in these grid segments by not allowing new PV installations.

The National Distribution Grid Structure

The Legal Framework and Operation of the National Transmission and Distribution Grids

In compliance with the European Union Directive 2009/72/EC regarding the adoption of common rules in the organization of the European Union electricity markets, and in compliance with Law 4001/2011, two 100% subsidiaries of the Public Power Corporation S.A. (PPC) were created, namely IPTO S.A. (Independent Power Transmission Operator S.A., or ADMIE) and HEDNO S.A. (Hellenic Electricity Distribution Network Operator S.A., or DEDDIE). According to the Law 4001/2011, IPTO is responsible for the management, operation, maintenance, and development of the Hellenic Electricity Transmission System and its interconnections, whereas HEDNO S.A. is responsible for the management, operation, development, and maintenance of the Hellenic Electricity Distribution Network.

Although ADMIE is a wholly owned subsidiary of the PPC S.A., it is entirely independent from its parent company in terms of its management and operation, retaining effective decision-making rights, in compliance with all relevant independence requirements of Law 4001/2011 and Directive 2009/72/EC.

The backbone of the Hellenic Electricity Transmission System consists of three double-circuit 400-kV lines that transmit electricity mainly from Western Macedonia, where 70% of the country's generation capacity is located, to the major electricity demand centers of

Central and Southern Greece, where 65% of the country's electricity demand resides. The Hellenic Electricity Transmission System consists of additional 400-kV and 150-kV lines, as well as 150-kV submarine cables that interconnect Andros and the Western Greece islands Corfu, Lefkada, Cephaloniia, and Zakynthos, and a 66-kV submarine cable connecting Corfu to Igoumenitsa.

As of June 30, 2012, 11.303 km of transmission lines, 291 substations, and 619 transformers with a total installed capacity of 50.749 MVA comprised the capacity of the Hellenic Electricity Transmission System [94].

Regarding the technical and regulatory framework, the code for the Hellenic Transmission System management was completed in November 2012. The code does not consider control or ancillary service provisions by PV systems connected at any voltage level to the electricity grid. There is a general statement that the transmission system operator may issue dispatch instructions for renewable energy and combined heat and power (CHP) units; however, these deal exclusively with limiting production for reasons of safe operation of the system, usually for wind plant, CHP, and hydroelectric plants.

The transmission and distribution of generated renewable electricity is guaranteed by national law and the power purchase agreements (PPAs). In cases where renewable energy plants are connected to congested areas, a predetermined upper limit of possible curtailments is contracted; some remuneration of renewable energy plants is predicted for such cases under L3851/2010.

Priority access (as defined by Directive 2009/28/EC) to the grids is ensured as long as the system security and security of supply are not jeopardized. Security criteria take into account various factors and parameters such as:

- Technical minima of conventional thermal power plants;
- Flexibility of conventional generation for load following;
- Required reserve; and
- Dynamic security aspects.

One of the most important duties of the TSO (IPTO S.A.) is the daily energy planning of the day-ahead scheduling, and one of tasks is the forecast of electricity injection from renewable energy plants. For the day-ahead forecast of renewable energy generation in the electric system, the main emphasis is given to wind plant energy production methodology and correction. The other renewable energy technologies being considered are small hydro, CHP, and biogas and PV plants. The next-day production forecasts of all the technologies except wind make use of a model developed by the Aristotle University of Thessaloniki that provides the energy that will be produced in the next day of each renewable energy technology, except PV, for each hour of the day. Regarding PV systems' production, the hourly energy production forecast of the previous day is taken into consideration as well as the weather forecast for the next day and, more precisely, the estimated radiation at selected locations, where PV systems have been installed and are being monitored. From the monitored PV systems connected to the MV, daily production data are collected. As to the PV systems connected to the LV grid, including PV systems on buildings, the hourly daily output is deduced according to the latest figures of total energy production provided by the DSO, DEDDIE (the Hellenic Electricity Distribution Network Operator, or HEDNO) [95] for the time period of measurement, which is every four months. Therefore, through this information, the change of installed capacity of PV systems is calculated. Moreover, the transmission system operator receives daily irradiation data for selected regions of the interconnected electrical system for the previous day and a forecast for the next day. A large investment is being planned by the TSO regarding the installation of a SCADA system in the distribution network.

National Distribution Grid Structure

The distribution network is radially operated. The nominal MV level is 20 KV, and the nominal LV level is 380 V/220 V.

The key quantitative figures for 2011 of the Hellenic Electricity Distribution Network are given below [95].

There are 228,900 Km of Network in total, including

- 107,500 km of MV network;
- 121,400 km of LV network;,
- 155,000 substations of MV/LV;
- 949 km of HV network, of which 205 km are in Attica and 744 km are in the non-interconnected islands;
- 224 HV/MV substations, of which 20 are closed-type substations, 199 are located within the interconnected system, and 25 in the non-interconnected islands;
- 7,503,265 customers (10,147 in MV and 7,493,118 in LV); and
- 45,716 GWH was the customers’ consumption (11,587 in MV and 34,129 in LV).

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

The main document describing the technical requirements and assessment methodologies for the interconnection of DER, and therefore for PV systems, to the distribution network is the following technical directives of the distribution utility PPC S.A., as well as the CENELEC and IEC standards [96][9]:

- Technical requirements for the connection of independent generation to the grid, and
- Guide for the connection of PV installations to the LV network.

Additional provisions are included in the distribution network and transmission system codes, as well as in the ministerial decree for the standardized grid-connection agreement of DG stations.

The first directive comprises the technical evaluation framework and the limits set for DG installations to be connected to the public LV or MV distribution network. Therefore, they are DG-specific documents. Although the first one is applicable for any DG station, it still comprises specific provisions for wind power stations. The second document concerns PV installations specifically, with installed capacities up to 100 kW.

More specifically, the following technical considerations have to apply.

Voltage Regulation

The DG shall not actively regulate the voltage at the PCC. The voltage change induced by the active power variations injected by the DG system must remain within ±3% (10 minutes average value).

Synchronization

Generators are connected to the network when voltage and frequency are close to nominal values, or at least within the regulation limits suggested by protective means.

• Synchronous generators shall use an automatic synchronization device with the following characteristics:

  - Maximum voltage difference: ± 10%;
  - Maximum frequency difference: ±0,5 Hz; and
  - Maximum phase difference: ± 10º.

In the case of many generators, the synchronization should occur sequentially with time intervals longer than the transient times. Usually time intervals of a few minutes are adequate.

[9] Please note that the national rules conform the following international standards: HD 384 Electrical installations of buildings; IEC; and CENELEC standards.

Table 32: Voltage and Frequency Operation Limits

	Interconnected Mainland System	Non-Interconnected (Autonomous) Islands
Voltage range	-20% to +15% of nominal 230 VAC	-20% to +15% of nominal 230 VAC
Frequency range	50 ± 0,5 Hz	51 Hz to 47.5 Hz

In cases where the above window limits are surpassed, the inverter should be automatically disconnected with the following time adjustments:

- Automatic inverter disconnection in 0.5 sec; and
- Inverter reconnection after 3 min.

Further:

- THD of the inverter current should not exceed 5%;
- The DC injection in transformerless inverters should not exceed 0.5% of the nominal or 20 mA for generators <16 A; and
- Protection against islanding is mandatory. The islanding norm is according to VDE 0126 or the equivalent.

Grounding

Grounding of the DG system shall be in accordance with HD 384-5-54/-55 and the relevant national standards. The scheme of the DG grounding shall not cause over-voltages at the equipment of DG or the equipment connected to the area EPS (electric power system). It shall also not disturb the coordination of the ground fault protection of the area EPS.

For systems operating in grid-independent operation (intended island mode):

- When a generator is operating as a switched alternative to a TN-system, a suitable earth electrode shall be provided.
- Protection by automatic disconnection of supply shall not rely upon the connection to the earthed point of the public supply system.
- DG systems capable of operating in intended island operation shall have a suitable connection between the system-neutral generator’s star point (three-phase systems) and the earth wire of the electrical installation.

When the DG system is operating in parallel with the electrical distribution network, there shall be no direct connection between the generator winding (or pole of the primary energy source in the case of a PV array or fuel cells) and the electrical distribution network’s earth terminal.

Electrical Disturbances

The disturbances emitted by the DG system on the network must remain within the limits described below:

- Limitation to harmonics emission:

The level of contribution of the installation to the distortion of the voltage must be limited to values making it possible for the DNO to respect the acceptable limits regarding the quality of the electricity delivered to the other users. The compatibility levels are given below. They are valid for both LV and MV according to EN50160 and IEC 61000-3-6.

Table 33: Compatibility Levels for Maximum Harmonic Distortion in LV and MV Networks

odd harmonics				even harmonics	
Non multiple of 3		Multiple of 3			
rank h	Relative voltage	rank h	relative voltage	rank h	relative voltage
5	6%	3	5%	2	2%
7	5%	9	1.50%	4	1%
11	3.50%	15	0.50%	6 to 10	0.50%
13	3%	21	0.50%	12	0.2%
17	2%	>21	0.2%	>12	0.2%
19	1.50%				
23	1.50%				
25	1.50%				
>25	(0.2+32.5/h)%				

The compatibility limiting levels for injection of harmonic currents to LV and MV grids are given in Table 33. Lh is the ratio of harmonic current Ih (in A at MV) and short-circuit power Sk (in MVA) of the installation at the PCC.

- Flicker

The DER SYSTEM shall not induce objectionable flicker to other customers. National rules conform to the IEC 61000-3-3, IEC 61000-3-7, IEC 61000-4-15, IEC 61400-21 standards.

- Power factor

The output power factor must remain within a range agreed upon by the DNO. Additional compensation measures may be taken.

Generator Operating Modes and Features in LV

The DER system connected in LV grid shall be able to operate under the following modes according to the type of the DG generation:

• Synchronous generators can regulate their output power factor, so compensation capacitors are not needed; and

• Many types of power converters that consume considerable amounts of reactive power may need compensation capacity. Self-commutated converters have small reactive power needs and are usually capable of regulating their power factor between 0.95 leading to 0.95 lagging.

Safety

The generator shall operate safely over the entire designed and declared operating range. For general requirements, EN61140 applies—protection against electric shock are common aspects for installation and equipment.

General requirements applicable to all operations of work activity on, with, or near electrical installations are stated in EN 50110.

For the installation, the LV code must be taken into account. Warning labels must be placed in live parts of the equipment according to Greek rules.

Required Control Capabilities by Photovoltaic Systems

At this time, there are no requirements for the control of PV systems in distribution grids. Regarding PV systems connected to the MV grid, the grid operator imposes its settings at the MV main switch of the PV plant; therefore, if the grid parameters excurse outside the preset windows, the main switch trips. The settings depend on the local grid situation.

Case Studies for High PV Penetration Scenarios

Regarding cases that are of interest in terms of PV penetration, the situation of one of the autonomous power systems of Greece, the island of Crete, is presented. For the autonomous power systems of Greece, there is a discrete code of grid operation (Code of Operation of Non-Interconnected Islands) [97] regulating technical and regulatory issues. Due to economic pressure and environmental goals, there is a need to replace expensive diesel fuel on the islands.

To exploit the high wind potential of the Aegean Sea islands, save on diesel fuel costs, and avoid lengthy power cuts due to extraordinary demand and hardware failure during the tourist season—as experienced on the island of Santorini in the summer of 2013—a number of interconnection projects have either been launched (Cycladic Complex) or are under study (Crete, North East Aegean islands, etc.) [98]. All of the interconnection projects are included in the National Transmission Development Plan (NTDP) for the period from 2010 to 2014 and beyond. The planned island interconnections may also serve the higher penetration of PV systems.

A remarkable renewable energy penetration case is in progress on the island of Crete [97]. Crete, with an annual peak load of 650 MW, is supplied by an isolated electrical system. The annual renewable energy penetration for 2012 was approximately 20%, and the maximum renewable energy capacity penetration 38.5% (280 MW of wind and 70 MW of PV).

During the early years of renewable energy operation, mainly with wind plants, some problems were encountered due to the sensitivity of wind turbines to voltage dips, faults on grid connection lines of wind plants to the HV substations (usually as a result of contamination of insulators), and due to the voltage settings of the protective disconnection devices of the wind plants. All of these problems were corrected by the DSO and the wind plant owners, and the FRT capability of newer wind turbines especially and impressively improved the performance of the system.

During the operation of the power system, PV systems provide their power output without any restrictions, whereas wind plants contribute by also taking into account the allowable instantaneous penetration levels, which are usually allowed to reach levels on the order of 40%. In cases when renewable energy penetration is higher than the allowable level, the power of the various wind plants is equally limited so as not to exceed this level. The main constraints for the instantaneous renewable energy penetration levels are determined by the technical minimum of dispatched thermal units, the spinning reserve (N-1), plus approximately 50% of the renewable power and additional network constraints [100][101].

The Energy Control Centre of Crete continuously monitors the wind plants, and a set point for maximum power output is given every 5 minutes in cases where this is required. However, there are periods when the operators judge to operate the electrical system with higher instantaneous renewable energy penetration levels (up to 60%), as shown in Figure 37.

The Energy Control Centre of Crete also selectively monitors online some PV plants at various locations on the island, and by an up-scaling methodology the total PV production is claimed to be calculated with a good accuracy, which helps in the daily scheduling of the conventional plants. The distributed PV plants have also been shown to support the maintenance of the voltage level in the acceptable range throughout the grid during the daily hours. The experience in island grids has generally shown no increase in the amount of required reserve capacity but increases in the use of operating reserve (regulating power 10 min.–15 min).

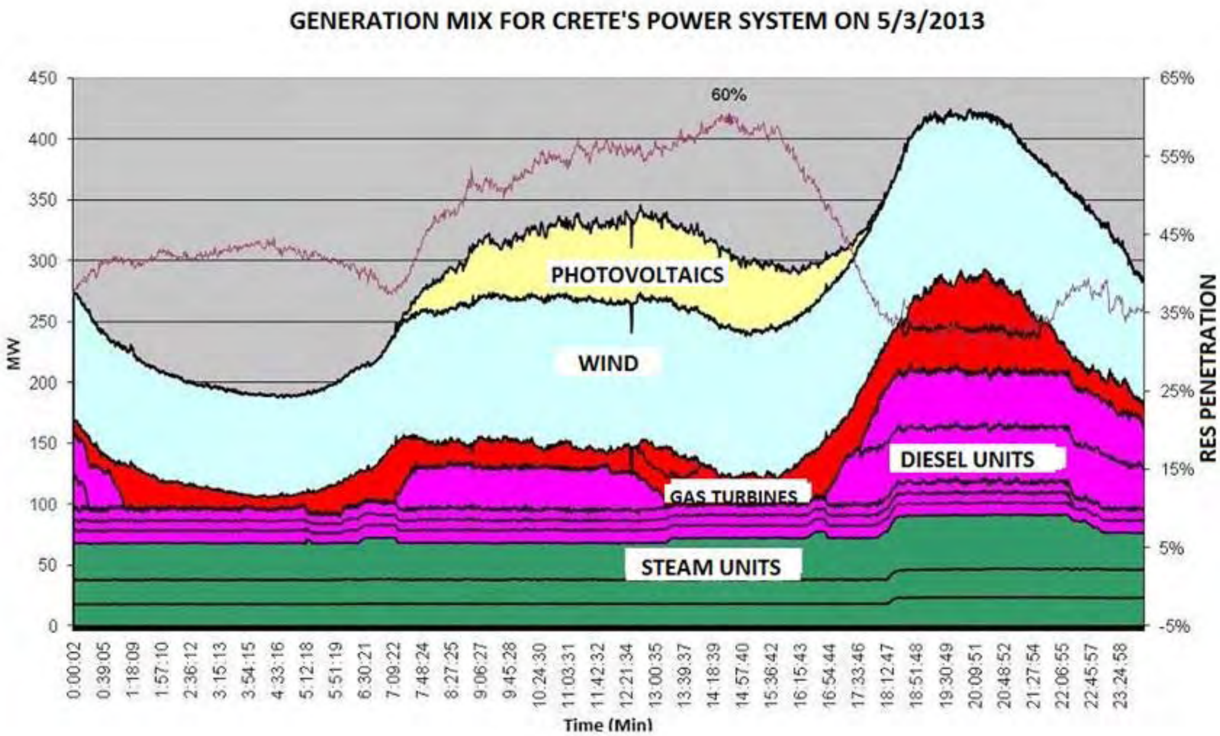
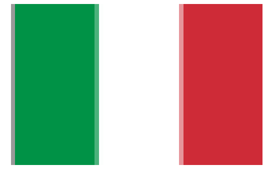


Figure 37: Generation mix for Crete's power system on May 3, 2013, and renewable penetration level (violet line) [99]

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

An ambitious national target for RES, namely 20% on the final energy consumption, 2% above the mandatory level of 18% as set by Directive 2009/28/EC was targeted by Law 3468/2006 in Greece. The same law further sets a specific target for the renewable electricity share of 40%.

Further, according to the National Renewable Energy Action Plan (NREAP) [102] of Greece, published in July 2010, the government had set for all the renewable energy technologies, including PV, targets for the years 2014 and 2020 to fulfill the European Union mandatory and national target regarding the fraction of electricity consumption from renewables. The targets for PV systems were 1,500 MW for the year 2014 and 2,200 MW for 2020. Currently (data of September 2013), the total PV installed capacity for grid-connected PV plants in Greece has surpassed 2,500 MWp. Therefore, in view of the current situation, there is a need to redefine the country's 2020 targets for each renewable energy technology. The government has to update its targets and take appropriate measures so that the PV market sector, where several thousand companies are active and more than 25,000 people are employed, remains engaged in its activities. Further, it also has to take into consideration all benefits and charges of all forms of energy and the initiative to transform the electricity market into a simple, transparent, and fair operating scheme for all players and the consumers. One such measure is the introduction in November 2013 of Law 4203/2013, which allows net-metering for PV systems of all sizes and small wind turbines for auto-producers in Greece. The PV systems that make use of net-metering are exempt from any suspension of the licensing process. The energy produced by the PV plant is fed into the distribution network and is subtracted from the energy consumption of the auto-producer in each count cycle (every four months). Any excess energy provided to the grid resulting from the previous offsetting procedure receives no compensation. Especially for public bodies that install PV systems in the framework of European programs, it is already provided that up to 20% of the total energy produced per year may be compensated by the respective feed-in-tariffs.



Italy

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At the end of year 2012, the installed PV capacity in the Italian power system was 16.6 GW; 18.3 TWh of energy were supplied by PV [103] on a total energy demand of 325 TWh. The PV penetration is very high, taking into account that in 2012 the Italian peak load was 54 GW. Table 34 summarizes the recent statistics about PV generation and power consumption in Italy.

Table 34: Statistics on PV Generation and Power Consumption in Italy

Statistic	Value	Year
Installed PV capacity (nationwide)	17.1 GW	Status: 08/2013 [104]
Peak load (nationwide)	54.1 GW	Status: 31/12/2012 [103]
Total generation capacity	128.1 GW	Status: 31/12/2012 [105]
Total energy generated by PV in 2012	18 862 GWh	Status: 31/12/2012 [105]
Share of PV on total energy consumption in 2012	6.1%	Status: 31/12/2012 [105]
Share of installed PV capacity connected to HV level	5.8%	Status: 31/12/2012 [106]
Share of installed PV capacity at HV/MV substations	n.a.	
Share of installed PV capacity connected to MV level	63.3%	Status: 31/12/2012 [106]
Share of installed PV capacity at MV/LV substations	n.a.	
Share of installed PV capacity connected to LV level	31.0%	Status: 31/12/2012 [106]
Average size of PV system	34.3 kW	Status: 31/12/2012 [106]

A rate of 96% of the installed plants (458,265) is connected to the LV level; only 20,000 PV plants are instead connected on the MV level, but they represent the 63.3% of the total installed power capacity [106]. Only 229 PV plants are connected to the HV level. Figure 38 depicts the allocation of the installed PV plants in the 20 Italian regional areas (year 2012 [106]).

Figure 38: Percentage of installed PV plants in the Italian regions (2012) [106]

The National Distribution Grid Structure

The Italian grid is synchronously connected to ENTSO-E continental Europe area (50 Hz), with the exception of the Sardinia island, which is asynchronous and linked to the mainland by means of two HVDC links (200-kV SA.PE.I. and 500-kV SA.CO.I.). The extra-high voltage (EHV) transmission levels are the same as in Germany (220 V, 380 kV); whereas the sub-transmission HV is operated at 132 V, 150 kV.

The distribution MV and LV networks are radially operated and consist of 1,232,000 km of lines (year 2012 [107]): 385,284 km at the MV level; 846,507 km at the LV level.

MV Level: The MV distribution grid mainly covers the standard range from 15 V to 20 kV, with few exceptions included in the larger range from 5 V to 23 kV. The rated capacity of HV/MV transformers in primary substations is usually between 16 MVA and 63 MVA, but some exceptions are in the larger range from 10 MVA to 100 MVA. The MV level is realized as a three-phase star system operated in a radial scheme either in urban or in rural areas. The star point is ungrounded or grounded by means of Petersen Coil aimed to limit the arcing currents during ground faults. The technical Italian standard CEI[10] 0-16 [108] establishes the limits for active/reactive power exchange and control.

LV Level: The three-phase with neutral conductor LV distribution level has a nominal voltage of 400 V/230 V. The rated capacity of Delta-Star MV/LV transformers, in "secondary" substations for energy supply to households, is typically from 50 kVA to 630 kVA, whereas higher rates (typically 1,000 kVA, 2,500 kVA) are possible for MV industrial users or energy producers. The general practice of Italian distributors doesn't include the remote active power control of DG connected to the LV level. However, the recent Italian standard CEI 0-21 [109] establishes that, in the case of the availability of a proper communication system, remote control should be implemented for generating plants that have a rated power higher than 6 kW.

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Legal Framework

The Legislative Decree of March 16, 1999, n. 79 [110], defines general provisions on grid access within the liberalization process of electricity markets (the Italian Electricity Market started on April 1, 2004) and states the DSO obligation to allow the connection for the users that fulfil the technical rules.

The Authority for Electric Energy and Gas (AEEG) defines the technical and economical procedures for new connection facilities. In particular, the AEEG resolutions 99/08 and 328/2012 implement the TICA[11] procedure [111] for DG connection on the LV-MV distribution network. According to this procedure, the counterpart of the plant operator will be the DSO if the nominal generating capacity is below 10 MW; bigger plants will be instead connected to the HV-level grid and the TSO will be their counterpart (§3 TICA). Concerning the voltage level of connection point (§2.4 TICA):

- The LV level will be considered in cases with nominal generating capacity up to 100 kW;
- The MV level will be considered in cases with nominal generating capacity up to 6,000 kW;

[10] CEI: Italian Electrotechnical Committee (Comitato Elettrotecnico Italiano - http://www.ceiweb.it/it/).
[11] TICA: Guideline for active DG conntections ("Testo Integrato per le Connessioni Attive).

- The existing voltage level will be applied in cases with an already-existing connection point (within the available connection capacity); and

- On the basis of technical reasons, the grid operator may supply the connection service at the LV and MV levels in cases with generating capacities respectively higher than 100 kW and 6,000 kW.

Connection costs have to be borne by the plant operator with the exception of extra costs in cases where the DSO choses a connection solution that is more expensive than the minimum technical one; in the latter case, the DSO has to pay for the extra costs. The TICA procedure also provides guidelines concerning the cost estimation of connection.

Technical Framework

According to the above AEEG resolutions; the CEI standards are based on EN 50160 and represent the main national technical references for connections on the distribution network. In particular, CEI standard 0-21 [109] (last updated in 2012) sets up the technical rules for connection on the LV level; whereas CEI standard 0-16 [108] (last updated in 2013) states the rules for connection to the MV level. The requirements for DG connection as set out by CEI 0-16 and CEI 0-21 have also been endorsed in a recent annex (A70 [113]) of the grid code of the Italian TSO.

Required Control Capabilities by Photovoltaic Systems

AEEG resolution number 84/12 [112] states which DGs connected to the MV-LV distribution network have to comply with annex A70 [113] of the Italian grid code.

Distributors have the responsibility of the A70 rules fulfillment in cases with connected users having rated power not lower than 1 kW; when complete fulfillment of the A70 rules is reasonably not possible, the DSO may ask for proper derogations to the TSO. All of the new generating plants connected at MV-LV distribution levels have to stay connected in case of normal and emergency conditions; in particular, annex A70 defines the operating ranges for voltage and frequency (see Table 35). In cases with DG plants having rated power higher than 6 kW and connected before April 1, 2012, a technological adjustment (retrofitting) is required.

Table 35: Requirements for Active Power Control of PV

System Size	Requirements	Date of Connection	V Level	Reference
$P_N \geq 1$ kW	Remote control, in case remote signals are available. Operation range ensured: 85%Vn≤V≤110Vn%; 47.5≤f≤51.5Hz (in case of transients due to HV level) or 49.7≤f≤50.3Hz (in case of transients due to MV level)	From 01/04/2012 to 30/06/2012	MV	§4.1 AEEG 84/2012
$P_N \geq 1$ kW	Remote control, in case remote signals are available. Operation range ensured: 85%Vn≤V≤110Vn%; 47.5≤f≤51.5Hz (in case of transients due to HV level) or 49.7≤f≤50.3Hz (in case of transients due to MV level). Active power modulation with frequency droop 2.4% in the over-frequency range 50.3≤f≤51.5Hz. LV FRT (LVFRT) capability if rated power no less than 6 kVA.	From 01/07/2012	MV	§4.1 AEEG 84/2012
$P_N \geq 1$ kW	Operation range ensured: 85%Vn≤V≤110%Vn; 49≤f≤51Hz	From 01/04/2012 to 30/06/2012	LV	§4.1 AEEG 84/2012
$P_N \geq 1$ kW	Operation range ensured: 85%Vn≤V≤110%Vn; 47.5≤f≤51.5Hz with different triggering time on the basis of remote protection control availability.	From 01/07/2012 to 31/12/2012	LV	§4.1 AEEG 84/2012
$P_N \geq 1$ kW	Operation range ensured: 85%Vn≤V≤110%Vn; 47.5≤f≤51.5Hz with different triggering time on the basis of remote protection control availability. Active power modulation (freq. droop 2.4%) in the over-frequency range 50.3≤f≤51.5Hz. LVFRT capability if rated power no less than 6 kVA.	After 31/12/2012	LV	§4.1 AEEG 84/2012
$P_N \geq 50$ kW	(retrofitting) Remote control, in case remote signals are available. Operation ranges ensured: 85%Vn≤V≤110%Vn; 47.5≤f≤51.5Hz (in case of transients due to HV level) or 49.7≤f≤50.3Hz (in case of transients due to MV level)	Before 01/04/2012	MV	§5.1 AEEG 84/2012
$P_N \leq 50$ kW	(retrofitting) Operation range ensured: 85%Vn≤V≤110%Vn; 49≤f≤51Hz (By 2014 June 30th)	Before 01/04/2012	MV	§5bis AEEG 243/2013
$P_N \geq 20$ kW	(retrofitting) Operation range ensured: 85%Vn≤V≤110%Vn; 49≤f≤51Hz (By 2014 June 30th)	Before 01/04/2012	LV	§5bis AEEG 243/2013 [114]
$P_N \geq 6$ kW $P_N \leq 20$ kW	(retrofitting) Operation range ensured: 85%Vn≤V≤110%Vn; 49≤f≤51Hz (By 2015 April 30th)	Before 01/04/2012	LV	§5bis AEEG 243/2013 [114]

Table 36 lists the current requirements according to AEEG resolutions number 33/08 and 187/11 and the CEI standards 0-16 and 0-21.

Table 36: Requirements for Reactive Power Control of PV

V Level	System Size	Technical Requirements	Reference
MV	P_N <400 kW	Minimum power factor of 0.9 (leading/lagging) and rectangular generator/inverter P-Q capability.	AEEG 33/2008 §8.8.5.3 CEI 0-16 [108]
MV	P_N ≥400 kW	Minimum power factor of 0.9 (leading/lagging) and semi-circular generator/inverter P-Q capability.	AEEG 33/2008 §8.8.5.3 CEI 0-16 [108]
LV	P_N ≤ 3 kW	Minimum power factor of 0.98 (leading/lagging)	AEEG 187/2011 §8.4.4.2 CEI 0-21 [109]
LV	3<P_N ≤ 6 kW	Minimum power factor of 0.95 (leading/lagging)	AEEG 187/2011 §8.4.4.2 CEI 0-21 [109]
LV	P_N > 6 kW	Minimum power factor of 0.9 (leading/lagging)	AEEG 187/2011 §8.4.4.2 CEI 0-21 [109]

Case Studies for High PV Penetration Scenarios

The Italian Authority for Electric Energy and Gas, AEEG, by means of the resolutions ARG/elt 25/09 (2009) [115] and ARG/elt 223/10 (2010) [116] about the monitoring of the DG development in Italy, commissioned two studies about the technical impact of dispersed generation on the distribution MV [117] and LV [118] levels, respectively. The aim of these studies was to assess the very stringent technical barriers for the DG penetration on the distribution network in Italy.

Concerning the first study on the MV distribution grids, a network data collection (year 2006) was carried out about 318 distribution MV bus bars in HV/MV substations with the corresponding distribution feeders (8% of the whole Italian distribution network). The represented MV distribution network was analyzed by means of short circuits and load-flow calculations to assess the DG (PV, wind, thermal, and geothermal) hosting capacity on the basis of maximum short-circuit current (i.e., protections breaking capacity), fast and slow voltage deviations, conductor capacity, and reverse power flow on HV/MV substation in a limited number of yearly hours. The reverse power flow, the maximum short-circuit current, and the slow voltage deviations are not the major barriers. Conductor overload is more restrictive than the above limits, even if fast voltage deviations (maximum assumed of ± 6%) are the main barrier. The cumulative histogram in Figure 39 ([117]) shows that the 85% of MV nodes allows an installed DG of 3 MW without grid constraints violations; almost the 65% of nodes allows instead the connection of 6 MW that is the maximum typical DG size on the MV level on the basis of the above-mentioned TICA procedure [111].

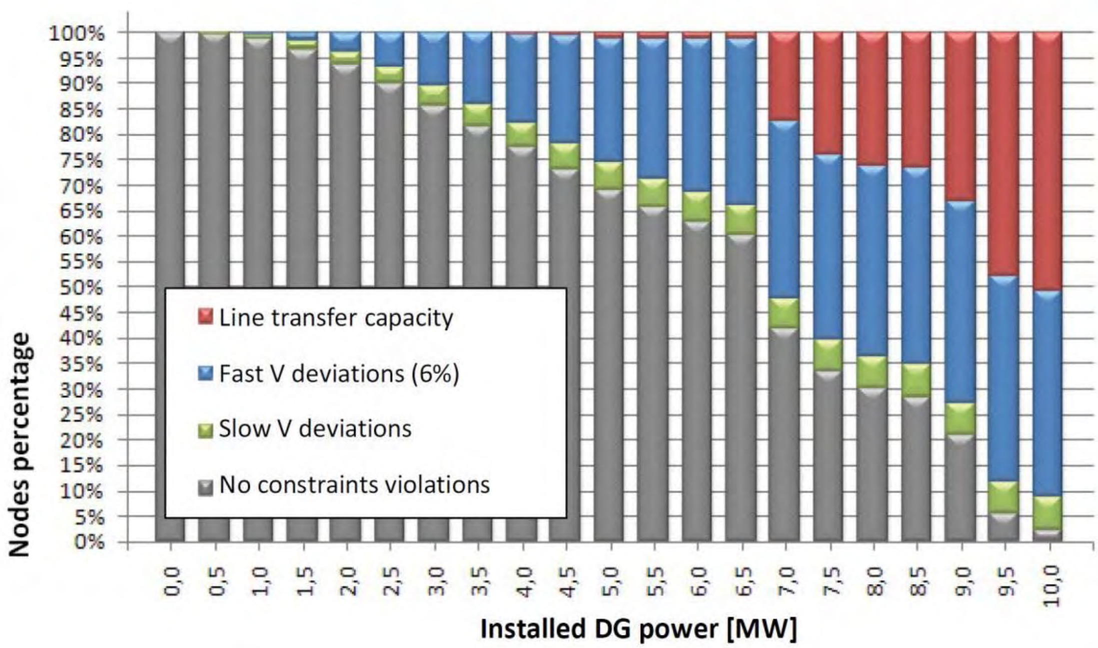


Figure 39: Hosting capacity in each MV node. Cumulative histogram of MV node percentages with the concerning installable DG powers [117]

In general, it was confirmed that less-stringent limits may be achieved by means of new measures on the protection system and the grid automation in addition to a more efficient management of the DG interface protections as stated by new standards mentioned above (CEI 0-16 [108]; Annex A70 of Italian Grid Code [113]).

The second study was performed on the LV distribution network starting from a network data collection (years 2007–2008). It concerns a reduced set of the distribution LV network consisting of 500 MV/LV substations. A further reduced subset of 16 MV/LV substations was then analyzed to assess the DG (mostly PV) hosting capacity on the LV level. The subset represents only the 1‰ of the national LV network; nevertheless, it was properly built with the aim to represent the most common configurations and situations. Considered constraints included slow voltage deviations within ±10%U_N (EN 50160), line capacity based on the conductor thermal limit, and fast voltage deviations from 5% to 10% U_N. The cumulative histogram in Figure 40 ([118]) shows that most of the nodes (83% of total analyzed) allow an installed DG of 30 kW; whereas 25% of the nodes allow an installed DG of 100 kW. Fast voltage deviations under 5% U_N are the most stringent constraints because, as shown in Figure 40, they affect the main share of nodes involving constraint violations.

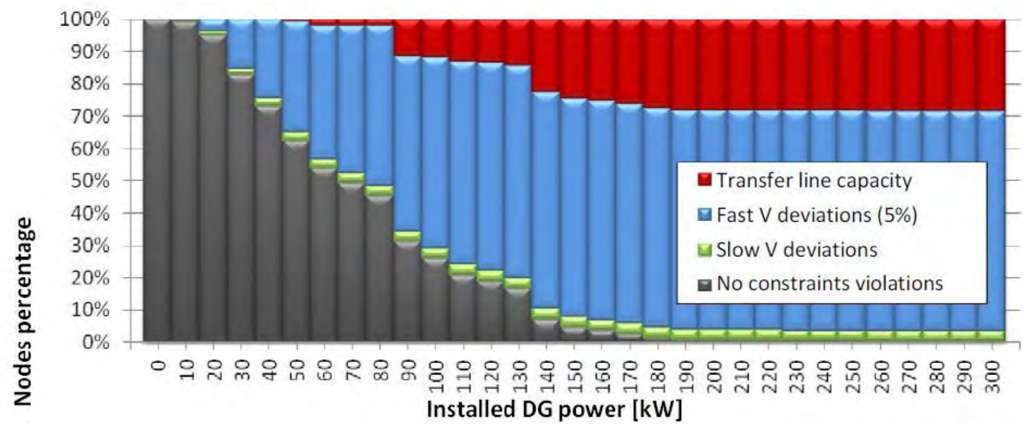


Figure 40: Hosting capacity in each LV node. Cumulative histogram of LV node percentages with the concerning installable DG powers [118]. Maximum fast-voltage deviations 5%

According to EN 50160, for fast voltage deviations, a higher limit of 10% UN may be assumed. Figure 41 shows that, with this larger limit, fast voltage deviations become a non-strict constraint: higher percentages of nodes—95% and 45%, respectively—allow 30 kW and 100 kW of installed DG.

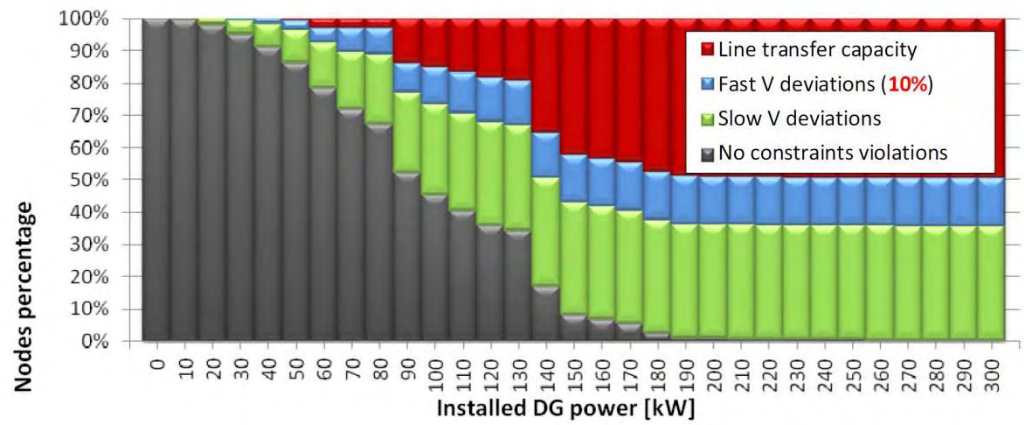


Figure 41: Hosting capacity in each LV node. Cumulative histogram of LV node percentages with the concerning installable DG powers [118]. Maximum fast voltage deviations 10%

Instead, line transfer capacity becomes a relevant constraint that can be faced with expensive network developments. The maximum short-circuit current in each LV line was found as a not much binding constraint; in any case, such a problem may be overcome by means of the increase of MV/LV substation numbers with the adoption of smaller size transformers (rated power lower than 630 kVA).

The study points out how a smart grid conception may facilitate the grid operation—e.g., in cases of fast voltage deviations, unintended DG tripping can be prevented by selective protection logics; slow voltage deviations may be faced with local voltage control by DG. In general, a proper communication system with a remote controlled interface of DG may help avoid local and system problems.

To reach a better quality of supply and a higher PV hosting capacity, local voltage control aimed to face slow voltage deviations is already foreseen by the recent standards CEI 0-16 (MV-level [108]) and CEI 0-21 (LV level [109]). These standards state that the distributors may ask for the adoption of the following voltage control logics:

- $\cos\varphi = f(P)$; power factor as function of injected active power P to limit over-voltages due to active power injections;
- $Q = f(V)$; exchanged reactive power Q as function of voltage to limit voltage deviations along the line.

These control logics have to be applied accordingly within the control capabilities shown in Table 36. Implementation of remote signals by DSO to achieve a coordinated DG voltage control is currently under discussion.

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

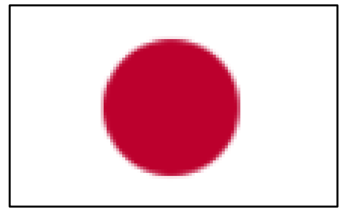
The implementation of European Directive 2009/28/CE, to reach the triple goal of the "20-20-20" initiative for 2020, fixes the renewable energy contribution on gross energy consumption at 17% for Italy.

Within the National Renewable Energy Action Plan (adopted June 2010), this RES-E energy quota was split into the following major energy sectors: heat, transport, and electricity. The contribution of renewable electricity generation was fixed at 26.4% of gross electricity consumption for 2020 (corresponding to about 100 TWh/year of renewable production).

According to the National Renewable Energy Action Plan [119] (see also Art. 4.1 of 2009/28/EC [120]), the 2020 target of solar installed capacity was fixed at about 8.6 GW (including 0.6 GW of solar-thermodynamic technology). To reach this objective, a feed-in tariff for PV systems was implemented (ceased with the last PV Support Mechanism, named "V Conto Energia," May 2012).

As of December 2012, the cumulative PV installed capacity exceeds 16.4 GW so that, including other renewable energy production (hydro, wind, biomass, and geothermal), the total renewable energy production covers about 27% of gross electricity consumption.

Further solar development is included in the last Italy National Energy Strategy (March 2013 [122]) in "grid parity" condition (about 1 GW/year up to 2020). To reach the new national renewable energy goal for 2020 of 35% to 38% of gross electricity consumption (about 120 TWh to 130 TWh/year of renewable energy production), the allocated investment resource is about 11.5 bln €/year to12.5 bln €/year for 20 years. To implement this energy strategy, new energy support mechanisms are currently under discussion.



Japan

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Table 37 shows statistics on PV generation and power consumption in Japan.

Table 37: Statistics on PV Generation and Power Consumption in Japan

Statistic	Value	Year
Installed PV capacity (nationwide)	4.9 GW	Status: 03/2012 [123]
Peak Load (nationwide)	156 GW	Status: FY2012 [124]
Total generation capacity	287 GW	Status: 03/2013 [124]
Total energy generated by PV in 2012	3,890 GWh	Status: FY2012 [125]
Share of PV on total energy consumption in 2012	0.4%	Status: FY2011 [125]
Share of installed PV capacity connected to HV and MV level	20%	Status: FY2011 [123]
Share of installed PV capacity connected to LV level	80%	Status: FY2011 [123]
Average size of PV system	<5 kWp	Status: FY2011 [126]

The National Distribution Grid Structure

The Japanese trunk transmission systems consist of 500-, 275-, 220-, 187-, 154-, and 132-kV transmission lines. Under trunk transmission lines, there are local transmission lines (110 kV to 66 kV) and distribution lines (33 kV, 22 kV, 6.6 kV to 100 V).

A general overview about the Japanese power grid structure is given in Figure 42.

HV Level: The nominal line-to-line voltages at the HV level are 110 kV, 77 kV, and 66 kV with neutral point high-resistive grounded system or arc-suppressing coil compensated grounded system (resonant grounded system by arc-suppression coil, neutralizer-grounded neutral system). The system topology is radial. Very large industrial facilities and multi megawatt-scale generation plants (conventional power plants, wind farms, large scale PV, etc.) are connected to this HV line.

MV Level: At this level, the definition of the voltages is divided at 7 kV in an ordinance of the Ministry of Economy, Trade and Industry (METI) in conjunction with the Electricity Business Act [127] (see notes below). Under 7 kV, the preferred nominal line-to-line voltage is 6.6 kV with a non-grounded system. This 6.6-kV system is widely adopted for MV distribution lines. The system topology is radial. However, distribution automation systems have been widely used for remote monitoring and automatic control of distribution equipment, thus the loop configuration is widely used with the radial operation.

In densely populated areas, 33-kV and 22-kV spot network distribution systems with a neutral point resistive grounded system are adopted to prevent equipment overcrowding and improve power supply reliability.

LV Level: The rated capacity of MV/LV transformers is usually between 10 kVA and 100 kVA. The nominal line-to-line voltage is 202 V ±20 V and line-to-neutral line is 101 ±6 V. The system is generally realized as an open delta connection. Single-phase three-wire systems (1p3w) are typically used for residential use. The system topology is radial and overhead lines with drop wires are generally used. Typical interconnected consumers are private households and small commercial consumers. The households usually use 100 V. As of the end of year 2012, 80% of the total PV capacity is connected to LV systems.

Please note that although the IEC 60050 (International Electrotechnical Vocabulary 601-01) classifies the voltage levels into the three levels (i.e., HV, MV, and LV), the definition of the voltages in Japan is defined in an ordinance of the Ministry of Economy, Trade and Industry (METI) in conjunction with the Electricity Business Act [127] as follows:

LV (LV_J): Voltages 750 V or lower for DC

Voltages 600 V or lower for AC

HV (HV_J): Voltages between 750 V and 7,000 V for DC

Voltages between 600 V and 7,000 V for AC

EHV_J: Voltages higher than 7,000 V

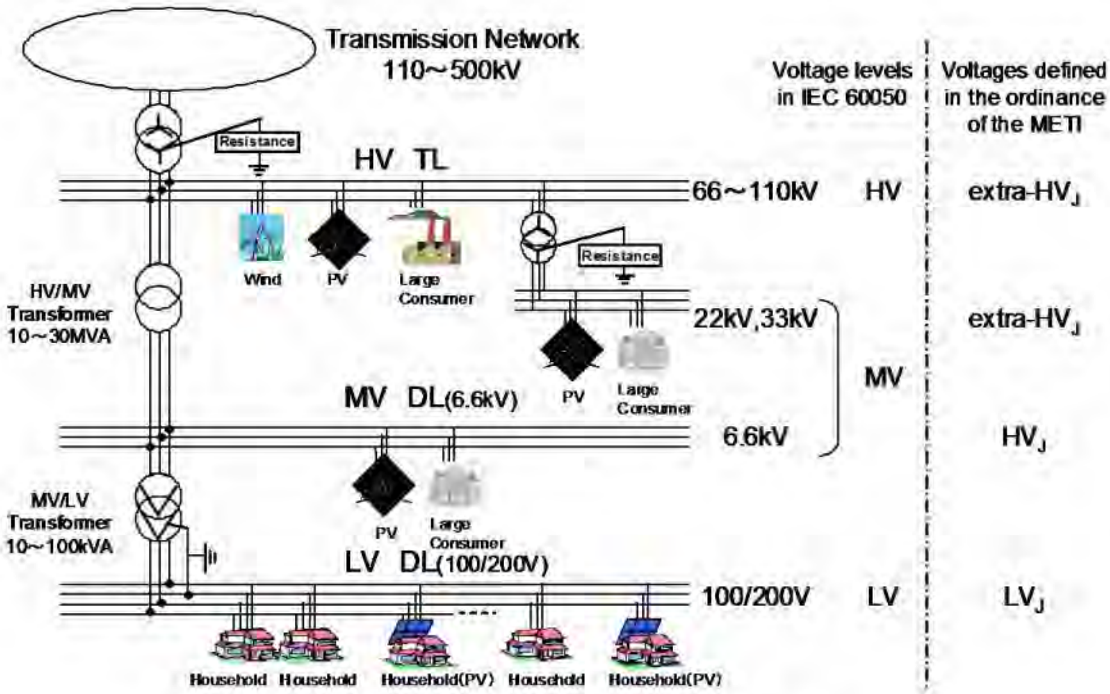


Figure 42: General structure of the Japanese power system

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Legal Framework

The ordinance of the METI in conjunction with the Japanese Renewable Energy Law stipulates that electric utilities must not refuse grid connection for electricity generated from renewables (PV, wind, geothermal, biomass, and small to medium hydro), except for the conditions stipulated by the ministerial ordinance. For example, PV and wind generators larger than 500 kW must agree to curtail generation when the total power generation in the grid (includes renewables) is reasonably expected to exceed the total demand. The requests of the curtailment basically need to be made on the day before curtailment is expected, and the grounds of the requests needs to be reported in writing immediately after the request. The duration of the curtailment is limited to less than 30 days per year. Utilities will make the necessary operational efforts such as the control of the conventional generators (except nuclear, hydro, and geothermal) and pumping up of the pump-hydro to accept the electricity from the renewables. However, utilities can refuse the grid connection if it is expected to exceed the limits of the current technical standard for the electricity quality such as voltage, even if more than 30 days curtailment is carried out. It is also stipulated that utilities can refuse the grid connection, in case the power generation of the renewables (listed above) is reasonably expected to exceed the transmission-distribution capacity limit. The grounds need to be disclosed in writing prior to the decision.

Technical Framework

The technical requirements of the grid interconnection of the generators are generally stipulated in the Electricity Business Act, and the detailed technical requirements are summarized in the Technical Standards for Electrical Equipment established by an ordinance of the METI. The official Interpretation of Technical Standards for Electrical Equipment is also published by METI. In addition to the technical standards, the Technical Requirements Guideline of Grid Interconnection to Secure Electricity Quality is published by the Agency for Natural Resources and Energy. This guideline mainly focuses on the grid interconnection of DG. To facilitate the business of the grid interconnection of DG, the Grid Interconnection Code (JEAC9701) is also authorized by Japan Electrotechnical Standards and Codes Committee (JESC). This code describes more practical requirement for the DG. [127]

The Technical Requirements Guideline of Grid Interconnection to Secure Electricity Quality was originally enacted in 1986 and has been revised as needed. The guideline covers all kind of generators that will be connected to the grid except those installed by utilities. It is recommended to have a cooperative discussion in the actual cases because the guideline only covers a typical case. The outline of the guideline is summarized in Table 38 and Table 39.

Table 38: Outline of the Technical Requirements Guideline of Grid Interconnection to Secure Electricity Quality in Japan (the criteria applicable only to PV) 1; *1: Specific case denotes that the capacity of the inverter is less than 2 kVA in 1p2w, less than 6 kVA in 1p3w, and less than 15 kVA in 3p3w, or that the power factor at the point of common coupling is usually close to 1, such as in residential systems. *2: ex. single-phase two-wire)

Network	LV$_J$	HV$_J$	Spot network	EHV$_J$
Definition of the network	LV distribution network includes single-phase two-wire (1p2w) 100 V, 1p3w 100 V/200 V, 3p3w 200 V and 3p4w 100 V/200 V	HV network to supply electricity to larger consumers and distribute the power from distribution substation to pole transformers. 3p3w 6.6k V is typically used.	More than two lines are supplying in parallel to the consumer. Typical voltage is 22 kV and 33 kV.	HV transmission network to supply electricity to larger consumers and transmit the power to substations. Below 35 kV can be classified as distribution network in some cases.
Generator capacity	< 50 kW	< 2,000 kW	< 10,000 kW	≥ 2,000 kW
Power factor (In case reverse power flow is permitted)	In general, higher than 85% on the grid and not to be in lead angle. Higher than 80% with reactive power control if it is necessary to avoid over-voltage. Higher than 95% if the power factor of the generators is not controlled by reactive power in specific case.(*1)		N/A	Must maintain the grid voltage. (Value is not defined.)
Automatic load limitation	N/A	Must have limiter if there is a possibility of the network overload in case of generator drop. In case of EHV$_J$ of higher than 100 kV, install Over Load Relay (OLR) and reduce the output according to the signal from OLR if necessary.		
Voltage fluctuation in normal operation	Reactive power control and/or active power curtailment to maintain the voltage within the control range (101 V ±6 V, 202 V ±20 V) except for the small capacity inverters (≤ 2 kVA (1p2w(*2)), ≤ 6 kVA (1p3w) and ≤ 15 kVA (3p3w)).	Must maintain the voltage in connected LV$_J$ (101 V ±6 V, 202 V ±20 V) in both generator drop and reverse power injection.	Must limit the load if the voltage fluctuation is expected to become larger than 1 to 2% of the normal voltage level by generator drop.	Must control the voltage if the voltage fluctuation is expected to become larger than 1 to 2% of the normal voltage level due to the grid connection of the generator.

Table 39: Outline of the Technical Requirements Guideline of Grid Interconnection to Secure Electricity Quality in Japan. (These criteria are applicable only to PV.)

Network	LV_J	HV_J	Spot network	EHV_J
Instantaneous voltage fluctuation (self-commutated inverter)	Use automatic synchronizing function.			
Instantaneous voltage fluctuation (externally commutated inverter)	Current limiting reactor should be used if more than 10% of the voltage deviation is expected in an instantaneous voltage drop in the grid.			As the same as others if more than 2% of the voltage deviation is expected.
Prevention of unnecessary disconnection	Not disconnect, if the duration of the voltage drop is shorter than the specification.	Not disconnect, or recover within the recloser's reaction time without affecting the reverse power relay and underpower relay, if the fault occurs in the non-connected line.	Disconnect the fault line but stay connected with other lines. Generator should not be disconnected.	Not disconnect, or recover within the recloser's reaction time without affecting the reverse power relay and underpower relay, if the fault occurs in the non-connected line.
Islanding	Not allowed.			Islanding operation is allowed with OFR and UFR or remote breaker.

By complying with the ordinance of the METI, PV systems shall be interconnected to the grid under the technical framework of the Grid Interconnection Code (JEAC9701). The outline of JEAC 9701 is described in Table 40. The requirements for grid interconnection are classified into the requirements for LV_J distribution lines, HV_J distribution lines, and EHV_J transmission lines, respectively. Interconnection to a 200-V/100-V distribution line is designed for rooftop application (residential small PV system), whose generating capacity is below 50 kW (typically several kW). Interconnection to a 6.6-kV distribution line is designed for industrial or business use PV systems whose capacity is between 50 kW and 2 MW. Interconnection to a 66-kV or higher voltage transmission line is designed for large PV systems (mega-solar) that have a capacity larger than 2 MW.

As for inverter certification scheme for grid interconnection, Japan Electrical Safety & Environment Laboratories (JET) provides a certification program for "Grid-connected Protective Equipment for Small Distributed Generation Systems" and certifies inverters with capacity less than 20 kW for interconnection to the LV network. This certification program aims to enable smooth grid interconnection by both utilities and distributed power producers. No certification scheme is established yet for the inverters of industrial or business use (larger than 20 kW). In this case, a PV system installer is required to have a technical consultation with the competent utility and ensure conformity to JEAC9701.

Table 40: Outline of Grid Interconnection Code (JEAC9701). *1. Standard active islanding detection scheme: A frequency feedback method with step reactive power injection (JEM 1498 (2012 JEMA)). See 2.8.3. *2. Voltage Q (reactive power) control

	LV_J distribution line interconnection 200 V/100 V	HV_J distribution line interconnection 6.6 kV	EHV_J transmission line interconnection 66 kV or higher voltage
Generating capacity	Less than 50 kW	50 kW to 2 MW	Lager than 2 MW
Power factor	More than 0.85 lag	More than 0.85 lag	0.90 lag to 0.95 lead
Voltage fluctuation	Autonomous control at DER Reactive power and active power control	Autonomous control at DER Reactive power and active power control	Autonomous control at DER VQC(*2) by EMS
Short-circuit current	-	-	Restriction act is needed.
Protection			
-Internal fault	OCR, OCGR	OCR, OCGR	The same protection relays as utility are required.
-DER outage	OVR, UVR	OVR. UVR	OVR, UVR
-Grid fault	DSR, OVGR	DSR,OVGR	The same protection relays as utility are required.
Anti-islanding	(*1) Standardized anti-islanding method	OFR,UFR Anti-islanding	OFR,UFR Anti-islanding
Disconnection method	Mechanical disconnection or inverter's gate block	Mechanical disconnection	Mechanical disconnection

Required Control Capabilities by Photovoltaic Systems

Active Power Control:

The requirements for active power controls including curtailment for PV systems in Japan are currently defined in the Technical Requirements Guideline of Grid Interconnection to Secure Electricity Quality as shown in Table 38 and Table 39. No compensation for curtailed feed-in loss will be made.

Reactive Power Control:

Distributed generators interconnected to LV_J or HV_J distribution lines are required to maintain the voltage of LV_J customers within regulated value by autonomous control function. That is to say, for regulated voltage 100 V, it must be maintained within range of 101 ± 6 V, and, for regulated voltage 200 V, it must be maintained within range of 202 ± 20 V. The autonomous control function required for inverters interconnected to LV_J or HV_J distribution lines is described in JEAC 9701. The autonomous control function must be realized by controlling active power and/or reactive power while keeping the conformity to the voltage requirement of the grid.

The outline of autonomous control required for LV_J interconnection is as follows:

- Monitoring the voltage at interconnecting point to the grid
- If the voltage is over the regulated value and the inverter is equipped with the reactive power control function, the inverter should perform reactive power control within the range of 1 to 0.85 p.f. through lead angle operation.
- If the voltage cannot be within the regulated value by reactive power control or the reactive power control is not equipped, an inverter should perform active power control until the voltage becomes the regulated value.

The autonomous control procedure required for HV_J interconnection is basically the same as the LV_J interconnection, except for the following items:

- The regulated voltage value is determined through discussion between the DG owner and utility.
- Reactive power control is perfromed by both power factor control and Static Capacitor (SC) control.

Anti-islanding:

A single-phase inverter in LV use must have both passive and active islanding detection functions in addition to OVR, UVR, OFR, and UFR. For the active method, the new standard anti-islanding protection method is defined in JEM1498 by Japan Electrical Manufacturers' Association (JEMA). The principle of the method is the frequency feedback method with step reactive power injection, which is called JSIDF (Japanese standard islanding detection function).

The JSIDF for high-penetration PV systems was developed with the following concepts.

1) High-speed islanding detection

2) Without mutual interference of active signals from multiple inverters

3) Without misdetection for frequency change or sudden voltage drop due to electric accident in bulk power systems.

There are two types of active signals in JSIDF. The algorithms of active methods are as follows:

1) Frequency feedback function

Frequency usually changes naturally after utility stops power distribution because of the imbalance in demand and power generation. Frequency feedback function injects reactive power to increase the frequency change to detect islanding. Reactive power is injected synchronously from each inverter because the same frequency value can be detected at each inverter. The correlation between frequency change and injected reactive power is shown in Figure 43.

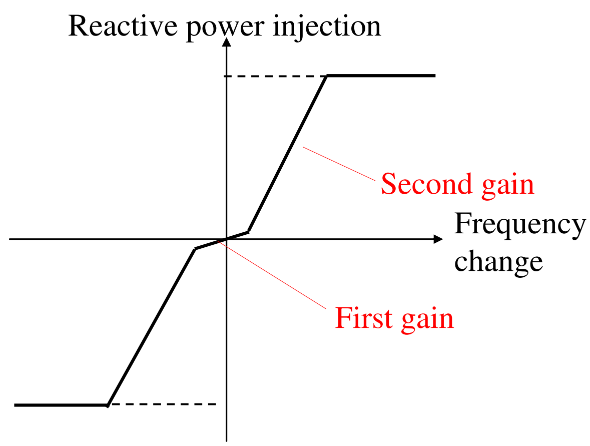


Figure 43: Frequency feedback function of JSIDF

The first gain is set smaller than the second gain to reduce reactive power injection during a normal power grid condition. The second gain was set to larger value to collapse the reactive power balance. The threshold frequency between first and second gain is +/- 0.01 Hz. The maximum absolute reactive power is 0.25 p.u.

2) Step injection function

Step injection function is applied to assist the frequency feedback function when frequency change does not occur after the power distribution stops under the power balanced condition. We focused on the harmonics distortion of voltage because it varies due to the characteristics of transformer.

Step injection function injects reactive power in case the total harmonics distortion (THD) voltage increases over 2.5 V and continues three cycles and frequency does not change during these three cycles.

The reactive power is injected only two cycles. If frequency changes after the two-cycle injection, frequency feedback function will be operated. From the 2nd to 7th voltage harmonics is used to compute THD.

Fault-Ride-Through:

FRT is required for DES (distributed energy source) so as not to be disconnected from the grid at the time of temporary voltage drop due to the fault at transmission line or load switch over operation. As is the high penetration of PV systems realized, FRT becomes an essential function to ensure the stability of power system. If most of PV systems are disconnected from the grid under such conditions, large-scale power supply failure will be caused and the power system will get unstable.

As described in 2.8.2, grid-interconnection requirements are classified into the voltage classes of distribution lines or transmission lines to which the DES is interconnected. But FRT, being di-electric duration capability of DES itself, needs to be specified by the kind of DESs. The necessary FRT function required for PV systems had been discussed and authorized at first among every type of DES.

Figure 44 shows the FRT requirements for PV systems. The requirements are classified into the requirements for a single phase inverter and a three-phase inverter. When you test the FRT function of a three-phase inverter that is used for PV systems of large capacity, cost or space factor should be considered to lead to practical testing procedures.

FRT requirements are to be applied step by step from the tentative specification stage to the final specification stage, considering technological development. FRT requirement for PV systems is being translated and transferred to other types of DERs, that is to say, battery systems, fuel cell systems, and gas engine cogeneration systems.

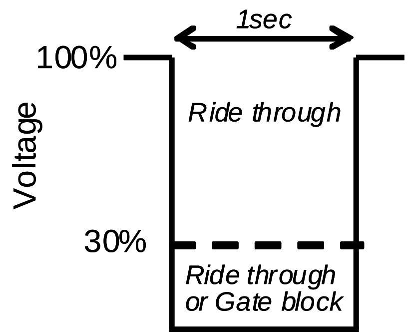
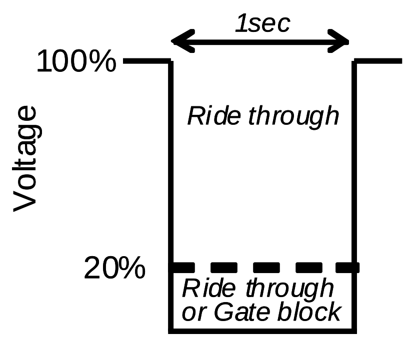
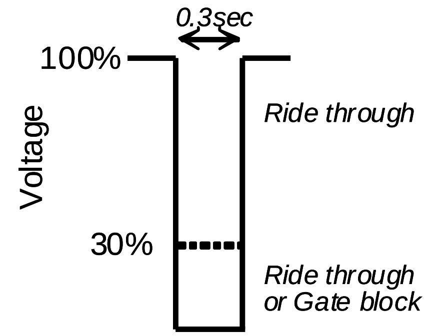
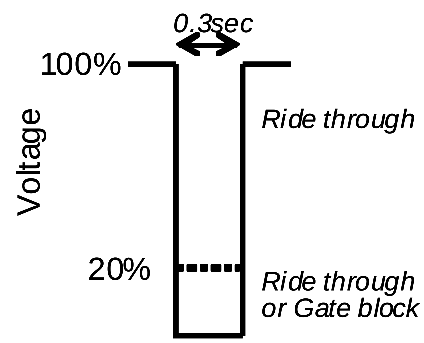
	Single phase inverter	3 phase inverter
LV duration capability	[Tentative] until Mar.2017  [Final] after Apr.2017 	[Tentative] until Mar.2017  [Final] after Apr.2017 
Response time to return to 80% of rated voltage	[Tentative] until Mar.2017 **within 0.5 sec** [Final] after Apr.2017 **within 0.1 sec**	**within 1 sec**

Figure 44: FRT requirement for PV systems

Case Studies for High PV Penetration Scenarios

The Demonstrative Research Project on Clustered PV Systems in Ota City:

Results presented here are summarized in the previous IEA report IEA-PVPS T10-06-2009.

The Demonstration Projects for Next Generation Optimum Control of Power Transmission and Distribution Network:

METI started the Demonstration Project for Next Generation Optimal Control of Power Transmission and Distribution Network (NG-TDN project) [128] in August 2010 with the participation of 28 entities consisting of three universities, electric power companies, electric appliances manufacturers, trading companies, and so on. The objective is to establish fundamental technologies to solve the issues believed to be caused by massive installation of PV systems to the power grids.

There are two major categories regarding issues arising from massive integration of PV systems into a power grid:

1) Voltage in distribution networks

   Due to a reverse power flow from PV systems to the grid as well as large and rapid fluctuation of PV output, voltages in LV distribution lines sometimes deviate from the regulated range of 101 ±6 V

2) Power supply and demand balance within a whole utility area

   It has been argued that surplus power or energy and shortage of frequency regulation capability may take place when electricity demand is below a certain level (Figure 45) due to the uncontrollable nature and short-term fluctuation of PV output.

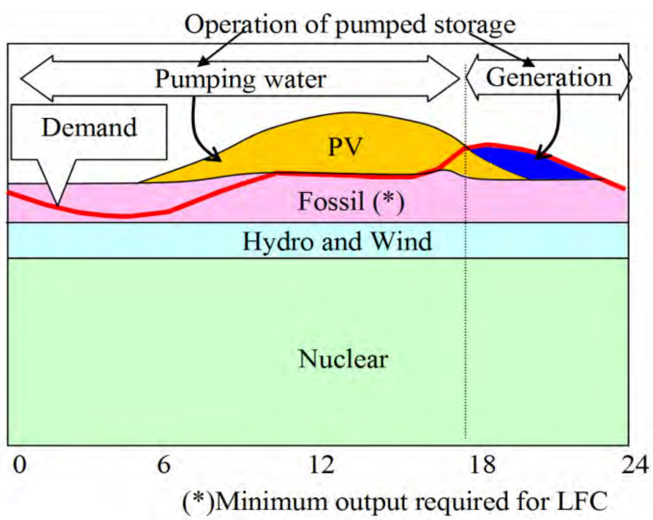


Figure 45: Schematic of the supply–demand balance throughout 24 hours in a system with a large number of PV systems

The NG-TDN project deals with the above issues by setting four groups according to technical fields to provide solutions to massive penetration of PV systems:

- Group 1: Methodology for optimum allocation and control of voltage regulating devices
- Group 2: Development of high-performance power electronic devices for distribution networks
- Group 3: Methodology for optimum control of customer's appliances according to demand-supply balance

- Group 4: Methodology for optimum planning and operation of power network considering cooperation with customers.

An example of the typical distribution network is shown in Figure 46. In the current voltage control technology, a voltage control function in the distribution network is realized by cooperative autonomous control of different equipment such as LRT (on-Load Ratio control Transformer), SVR (Step Voltage Regulator), and STATCOM. A tap position of an LRT or an SVR is controlled to put an estimated voltage at a supposed center of loads into the determined voltage range. Currently, these control parameters are settled by the information of impedance of the secondary distribution line. STATCOM is generally controlled to suppress only the rapid voltage change to avoid the confliction between the control response of SVR or LRT.

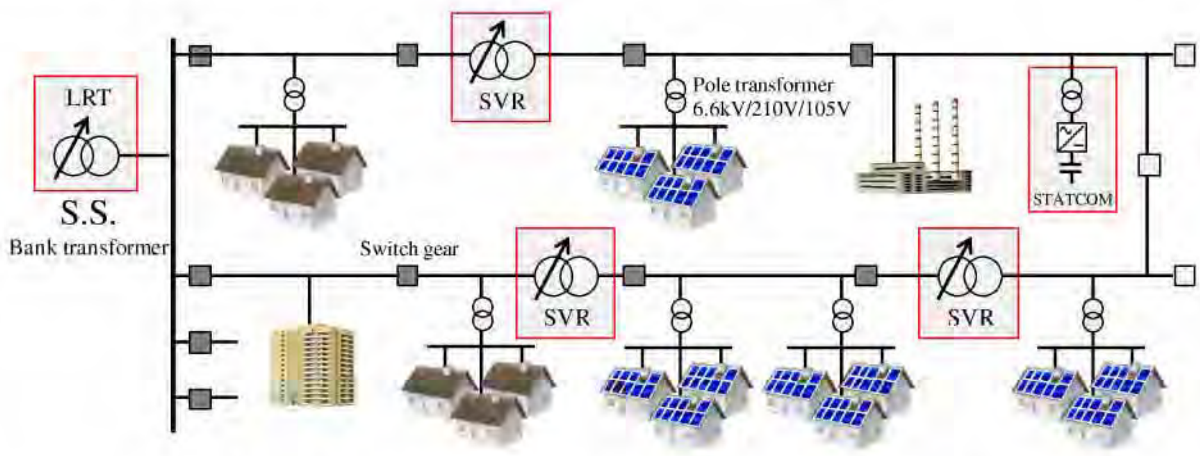


Figure 46: A typical distribution network with various voltage control equipment

Group 1 is trying to provide an optimum allocation and control of these voltage regulating devices to avoid voltage deviation from the prescribed range.

Autonomous Demand Area Power System (ADAPS):

Highly concentrated interconnection of distributed power generation including PV systems to the grid may have a negative impact on power quality and stability and the safety of the grid. To cope with those issues, the "Autonomous Demand Area Power System" was proposed by the Central Research Institute of Electric Power Industry (CRIEPI) as a future advanced distribution system [129]. Figure 47 shows the basic configuration of the ADAPS. The ADAPS is defined as the segment of the distribution system and existing distribution system is utilized at the maximum. The capacity of the system will be from about 100 MW to 200 MW. In addition to active and reactive power control of DG, grid voltage control devices installed in the grid side such as SVR, Static Var Compensator (SVC), and Loop Power Controller (LPC), were taken into account to cope with voltage variation and power flow congestion due to the interconnection of multiple DG in the ADAPS. The LPC is a new designed device consisting of two AC/DC converters linked to DC (back-to-back method) that enables the control of both power flow between two feeders and each feeder voltage simultaneously, as shown in Figure 47 [129].

For autonomous operation and control of DG and demand in each customer, a specific function called the Supply and Demand Interface (SDI) consisting of a customer's energy management system (EMS) with smart meter was proposed [129] [130]. The SDI is installed in each customer and deals with energy supply and demand with DG, storage battery, and load using a communication system to meet benefits for both the customer side and grid side such as compatibility of reverse power restraint of DG and effective energy use. Individual voltage control devices and SDI are operated in linkage with the central operation control system that manages the entire ADAPS.

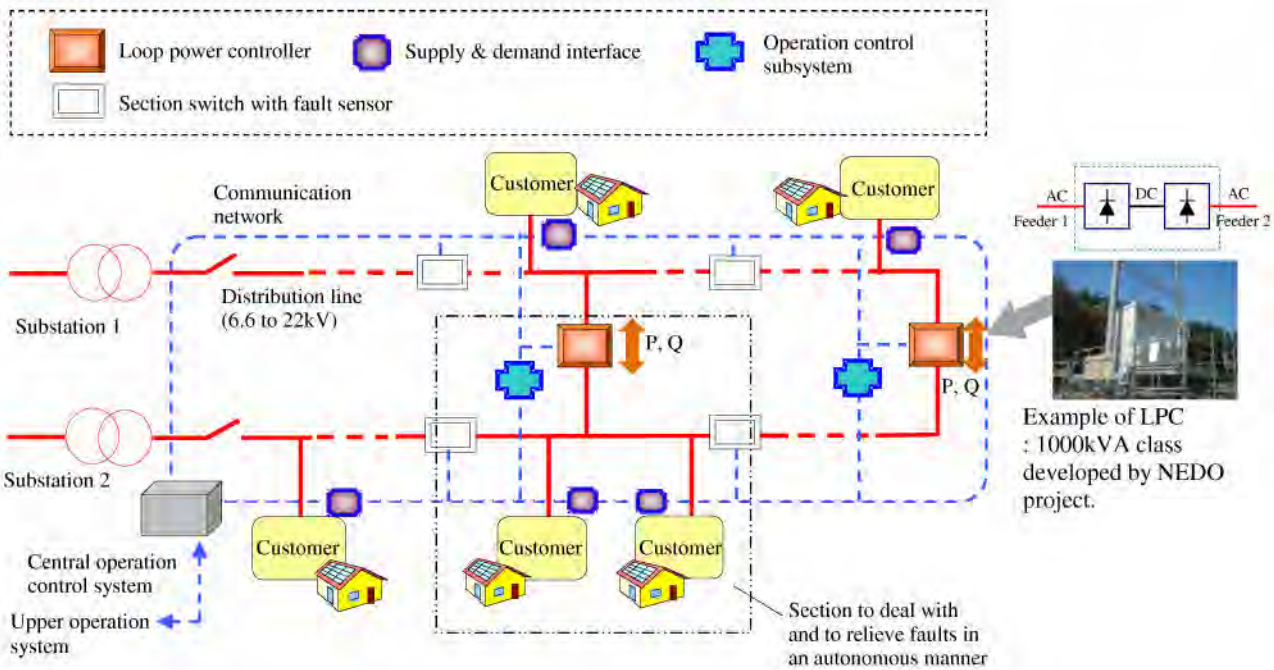
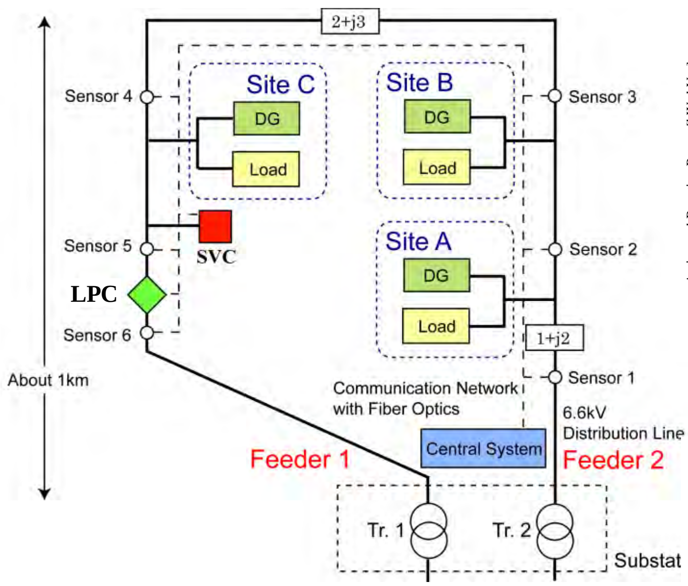
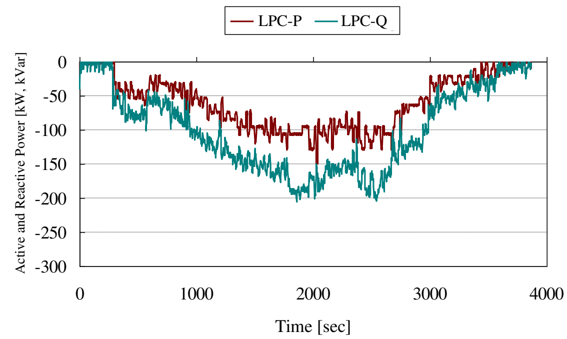


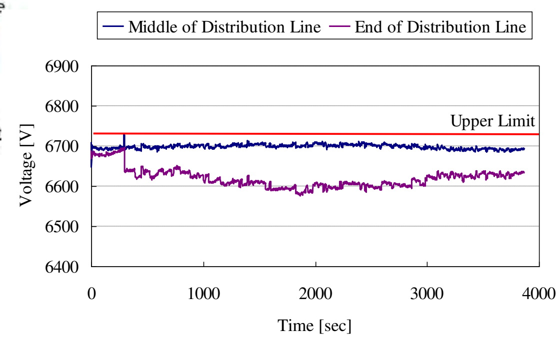
Figure 47: Configuration of ADAPS with LPC and SDI



(a) Experimental Distribution System



(b) Active and Reactive Power Changes of LPC



(c) Distribution Line Voltage Changes with LPC

Figure 48: Loop controller setup and results

Demonstration tests of the developed centralized voltage control system using voltage control devices such as SVC, LPC, etc., in ADAPS were carried out at the Akagi testing center of CRIEPI [129]-[131]. The experimental distribution system shown in Figure 48 (a) consists of a substation, 6.6 kV distribution lines, several line voltage sensors, communication network, three units of 100 kW simulated DG, three units of 200 kVA load, and the developed voltage control devices. Each DG is the inverter type generator simulating PV system. Two distribution lines of feeder 1 and feeder 2 are connected by the LPC.

Figure 48 (b) and (c) show typical test results using a 1,000-kVA LPC. Figure 48 (b) shows the LPC active power (P) and reactive power (Q) changes according to DG generation power and load consumption. The LPC absorbs surplus the active power of DG in feeder 2 and injects the power to feeder 1. As a result, the distribution line voltage of each location in feeder 2 is stably controlled under the upper limit shown in Figure 48 (c). Required device capacity and distribution line power loss can be generally reduced via a LPC compared to SVC [131].

Using Japanese average distribution line models, proper line voltage control measures according to the penetration rate of DG to distribution line capacity were evaluated by the means of demonstration tests and numerical simulations, taking account of the ability to control proper voltage range and system cost [129][131]. Results from the case in which DG is penetrating the LV distribution feeder are shown in Figure 49. In residential areas, a designed centralized control method using SVC or LPC using information of the whole power distribution system may be needed when the penetration rate reaches 65% or more. As the results show, the possible penetration rate in a feeder can reach 100% by the designed voltage control method combined with reactive power control of a PV system.

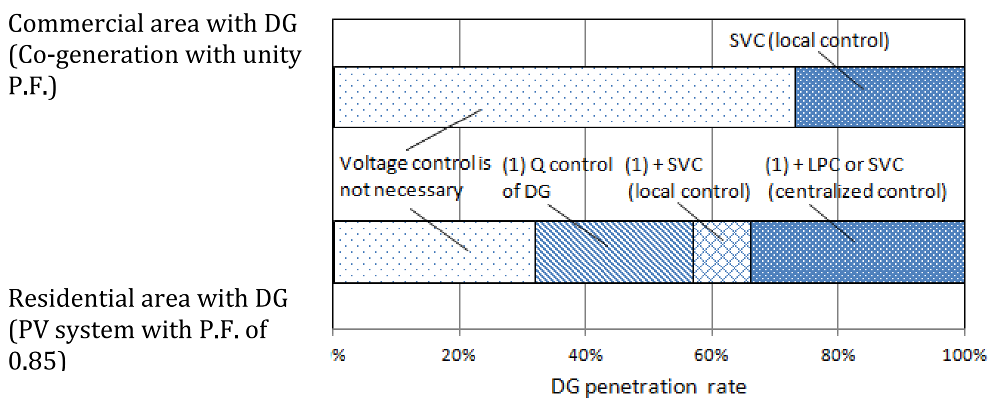


Figure 49: Evaluation results of proper voltage regulation methods according to DG penetration rate

Restraint of reverse power flow from PV systems is generally considered as an effective measure not only to maintain the power quality of the distribution line but also to restrain surplus power of whole utility system under future large penetration of PV systems. A method for utilizing PV generation power by customer's load control under the condition of limitation of reverse power given by the grid side was designed in the study concerning SDI of ADAPS [132][133]. The heat pump type water heater (HPWH) with hot water storage was mainly taken into account as the controllable load.

A proper operation of the planning method of the HPWH on the next day for each customer was developed [132][133]. The method satisfies both the required reverse power flow condition and the customer's benefit for minimizing electricity charge, preventing shortage of hot water, etc., regardless of predicted uncertainty of PV output, heat, and electric demand. The flow chart of the developed method is shown in Figure 50. Probability distributions concerning actual irradiance profile versus weather forecast, hot water demand, and other load are prepared from those past statistical data. Possible multiple scenarios of predicted profiles on the next day concerning PV generation power and the loads are extracted from those probability distributions. On the other hand, candidates of HPWH operation pattern on the next day are selected randomly. Focusing on satisfaction level to above requirements, the validity of those candidate patterns is evaluated respectively using the possible multiple scenarios of the predicted profiles. Genetic algorithm is used for selecting each operation pattern effectively. Finally the best HPWH operation pattern on the next day is selected. The method is also available to make charge and discharge plans for storage batteries including electric vehicles (EVs) for utilizing surplus PV power.

The demonstration test to evaluate the developed method was carried out using a 4-kWp PV system, 1.0 kW (3 kWh) HPWH system, and other residential electrical appliances [133].

Figure 51 shows an example of PV and load profiles on a clear day when the reverse power limit is set at 2 kW. About 50% of the expected PV generation loss can be utilized by daytime operation of HPWH according to the plan calculated by the developed method. As the results of year-round operation, average daily PV generation loss is significantly reduced from 1.34 kWh to 0.65 kWh. The reduction rate of average yearly electricity charges per customer reaches a maximum of 20%.

For future work including the ADAPS techniques, new coordinated operation and control methods of distributed smart communities and the whole power system will be investigated.

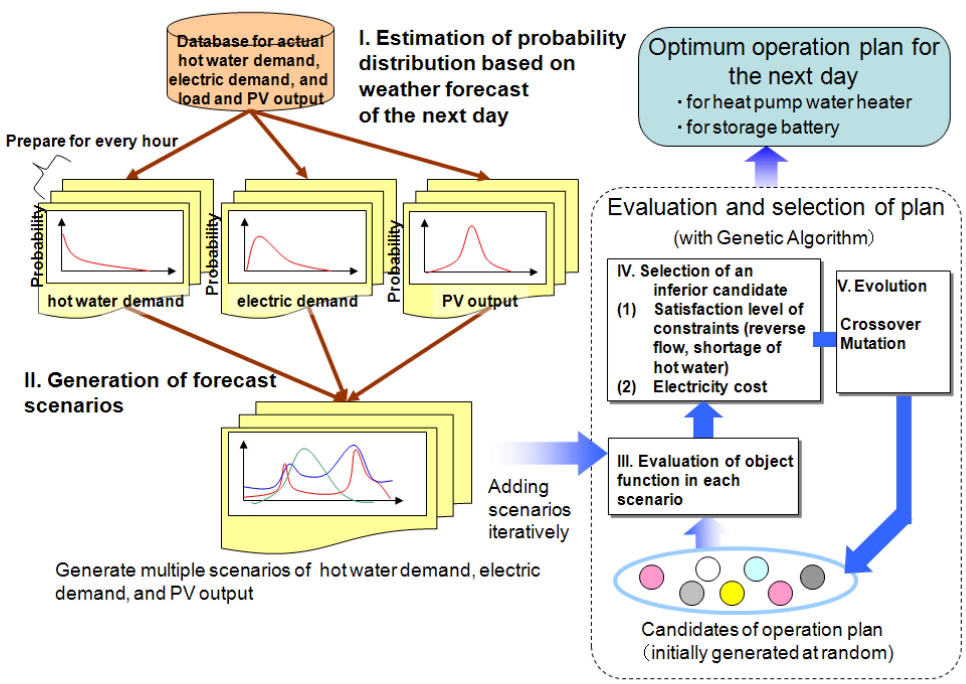
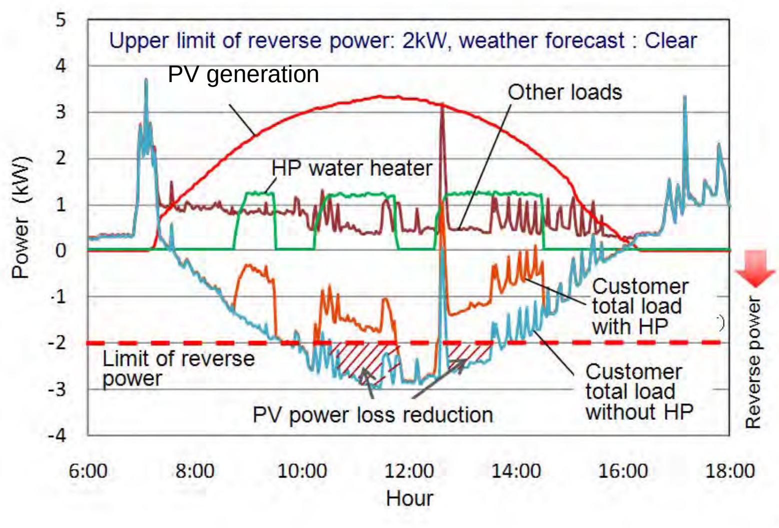


Figure 50: Flow chart of developed customer's appliances operation planning method



Note) 1 US$ = 100 yen. Electricity buying rate from utility is assumed 25.2yen/kWh from 10:00 to 17:00, 20.3 yen/kWh from 7:00 to 10:00 and from 17:00 to 23:00 and 7 yen/kWh from 23:00 to 7:00. Electricity selling rate to utility is assumed 7 yen/kWh from 7:00 to 23:00 and 5yen/kWh from 23:00 to 7:00.

Figure 51: An example of demonstration results of a developed operation planning method

Spain

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Table 41 shows relevant statistics on PV generation and power consumption in Spain.

Table 41: Statistics on PV Generation and Power Consumption in Spain

Statistic	Value	Year
Installed PV capacity (nationwide)	4682 MW (AC)	November 2013 (UNEF)
Peak load in 2013 (nationwide)	39640 MW	December 2013 (ENTSO-E)
Total generation capacity 2013 (including hydro)	104159 MW	December 2013 (ENTSO-E)
Total energy generated by PV in 2012	8,1 TWh	January 2013 (EPIA)
Share of PV on total energy consumption in 2012	2.99%	January 2013 (EPIA)
Share of installed PV capacity connected to HV level	17%	January 2013 (EPIA)
Share of installed PV capacity connected to MV level	48%	January 2013 (EPIA)
Share of installed PV capacity connected to LV level	36%	January 2013 (EPIA)
Average size of PV system	107 kW	January 2013 (EPIA)

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

The Spanish power system can be considered a partial electrical island due to its weak interconnection capacity to neighboring countries. This led to the development of two important aspects of the system operation in relation of the development of variable renewable energy sources (mainly wind) during the last decade:

- The grid codes or operational procedures (POs) required by the Spanish TSO, Red Electrica de Espana; and
- The Control Centre of Renewable Energy, CECRE, which has been in operation since 2006. CECRE is considered a worldwide pioneering initiative to monitor and control renewable power plants, specifically wind farms.

Taking into account the penetration of renewable energy in the Spanish power system, some POs apply to wind power and large PV systems, but their focus is on the prevention and resolution of system-related disturbances. This is what makes the Spanish situation unique in the European landscape compared to countries like Germany or Italy. In these countries the focus of grid code evolution has been to address mainly distribution-level challenges. However, it is worth mentioning the main characteristics of grid connection requirements for PV systems in Spain, as they could interact[12] with distribution systems operation or be extended to small PV systems:

- Forecasting of wind and PV production for unit commitment and dispatch
- P.O. 3.7.: Active power management for generators larger than 10 MW
- P.O.12.3/R/D 1565: FRT requirement (zero-power-mode) for all generators larger than 2 MW
- P.O. 12.3: Reactive current injection at FRT for all new generators larger than 2 MW

[12] Positively; the capabilities could be used for distribution system operation or negatively; their use could trigger new challenges at the distribution level.

- Submission of real-time data (V,P,Q) to the CECRE for all new generators larger than 1 MW
- Voltage support though a Q(V) static function and frequency support though a P(f) function for all new generators larger than 10 MW.

Case Studies for High PV Penetration Scenarios

Case studies presented in this section have been conducted by three Spanish DSOs: Union Fenosa Distribucion, Endesa Red, and Iberdrola Distribucion in the frame of the European project REserviceS. This revolves around two distribution networks, one at the MV level, and one at the HV level. The studied MV network is located in a peri-urban area with a mixed demand (50% residential, 20% commercial, and 30% industrial) while the studied HV network covers the central region of Spain (in Spain some DSOs operate the network up to 220 kV); in both cases, a high share of wind and PV is simulated. The study aims at analyzing the possible contributions of PV and wind generators (DGs) to the voltage control in distribution networks from an active management perspective. The following two voltage control strategies have been considered for the analysis:

- Business-as-usual (BAU) approach (current regulation):
    - Voltage control in MV networks by means of fixing MV bus bar voltages at primary substations
    - DGs produced with a constant power factor.
- Smart approach: the DSO optimizes voltage control by:
    - Fixing MV bus bar voltages at primary substations
    - Sending optimal voltage set points to generators connected to the HV and MV distribution networks (steady-state voltage control).

Moreover, ENTSOE's draft **Network Code** on demand connection reactive power requirements at the transmission/distribution interface ([134] Article 16) has been considered.

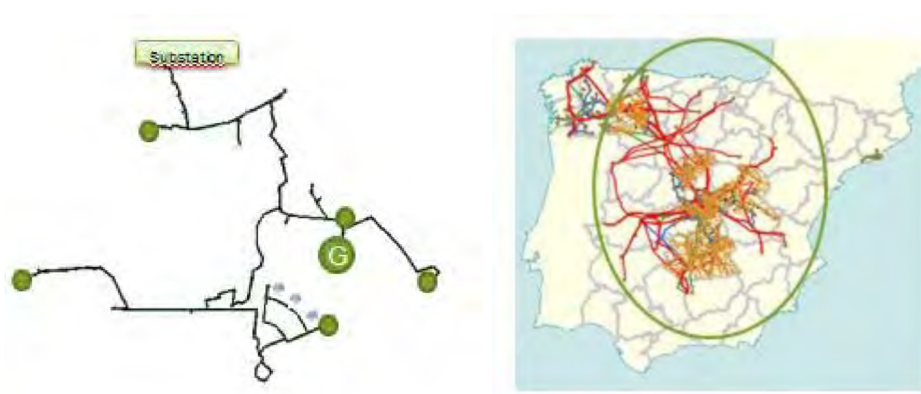

Figure 52: Overview of the networks considered in the case studied: a MV grid (left part of the figure) and a HV grid (right part) (Source: ReserviceS project 2014 [135])

The main characteristics of the two considered networks are given in Table 42.

Table 42: Characteristics of the Two Networks Considered for the Analysis. (Source: ReserviceS project 2014 [135])

	MV network	HV network
Line Rated voltage	15 kV	45-66-132-220-400 kV
Generation capacity	2.311 MW	1,300 MW
Peak Load	7MW	3,000 MW
Lines length	23 km	6,000 km
Installed PV capacity	0.331 MW	3.5 MW
Installed Wind capacity	0 MW	384 MW

Different penetration scenarios for wind and PV have been taken into account during the analysis of the two voltage control strategies. These scenarios are presented for the MW network and for the HV network.

Table 43: Wind and PV Scenarios Envisioned for the Analysis of the Voltage Control in the MV Network (Source: ReserviceS project 2014 [135])

MV Scenarios	Wind	PV	Other Generation	Demand
Current situation (DG1)	-	0.311 MW LV	2 MW CHP	Peak
PV increase (DG2)	-	0.311 MW LV 5 x 0.2 MW MV	2 MW CHP	Peak
Wind increase (DG3)	5 x 0.2 MW MV	0.311 MW LV	2 MW CHP	Peak
REserviceS scenario (DG4)	2 x 0.2 MW MV	0.311 MW LV 3 x 0.2 MW MV	2 MW CHP	Peak
Maximum DG (DG5)	5 W x 3.5 MW MV	0.311 MW LV	2 MW CHP	Peak

Table 44: Wind and PV Scenarios Envisioned for the Analysis of the Voltage Control in the HV Network (Source: ReserviceS project 2014 [135])

HV Scenario	Wind	PV	Other Generation	Demand
Current situation (DG1)	357 MW HV	3.5 MW HV	1492 MW HV	Off-peak

DG2	1000 MW HV	8 MW HV	1280 MW HV	Off-peak
DG3	357 MW HV 204 MW MV	3.5 MW HV	1290 MW HV	Off-peak
DG4	710 MW HV 510 MW MV	10.4 MW HV	630 MW HV	Off-peak

Moreover, other assumptions have been taken regarding the average R/X ratio of the MV network:

- R/X1: is the value of the R/X ration of the analyzed MV network (R/X avg = 1.5)
- R/X2 is a scenario corresponding to weak grids (R/X avg = 2.5)

Finally, different distributed generator behavior models have been developed depending on the type of technology. Wind turbines have been assumed to be equipped with a STATCOM enabling an unlimited Q provision at the point of common coupling. For MV connected PV systems, a limited Q provision with a cosφ of 0.85 has been assumed. Finally, no Q provision is assumed for LV connected PV systems and the other generators.

The DSOs involved in this analysis took also other assumptions beside the penetration levels, the R/X ratios, and the reactive power provision models for the DG. A high-level description of the methodology used to conduct the analysis and the assumptions is presented in Figure 53.

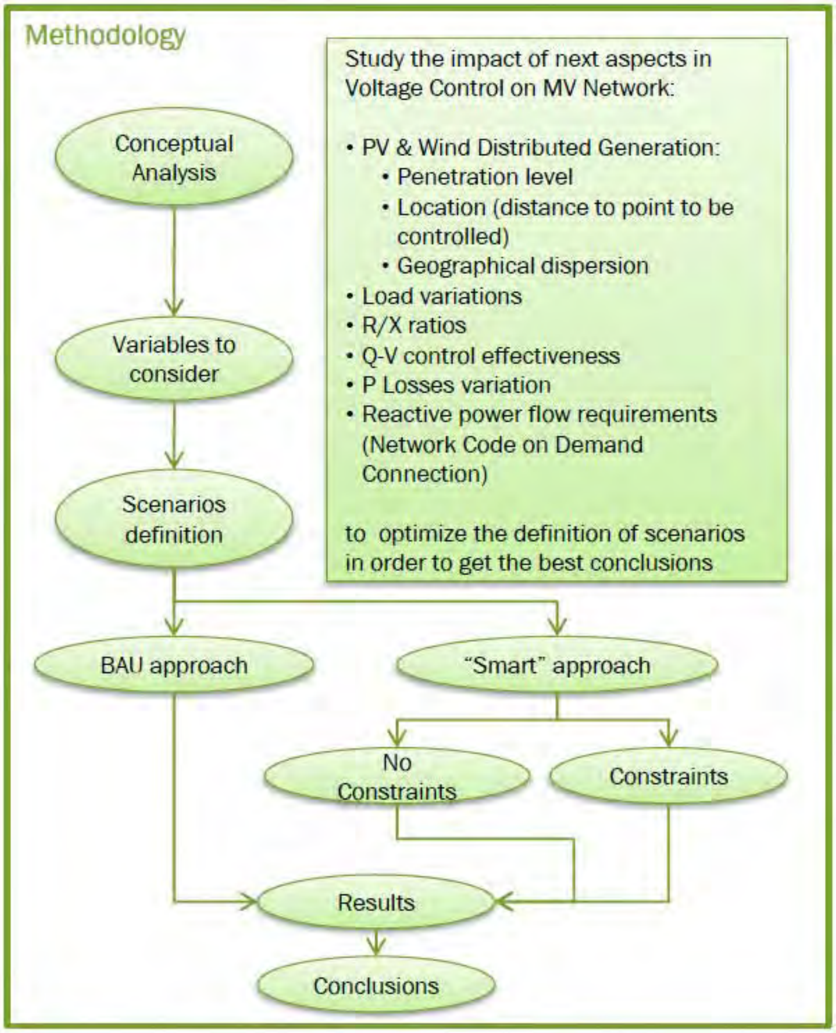

Figure 53: High-level description of the methodology and assumptions used for the analysis (Source: ReserviceS project 2014 [135])

Methodology

Two optimal power flow (OPF) analysis have been conducted using two different constraints:

- Minimization of Q provision for voltage limits fulfilment (0.93 ≤ V[pu] ≤ 1.07)
- Active power losses minimization subject to voltage limits fulfilment.

on the two R/X rations assumptions and the five (for MV) and four (for HV) penetration scenarios considered. As shown in Figure 54, the two OPF were performed to analyze four different impacts of DG penetration on the networks.

Case Study	Approach	Scenarios		Impact on Network			
		R/X ratio	Penetration of Distributed Generation	Effectiveness of Q-V control (DV, Q_{gen})	Impact of Q-V control on active power losses (P_{loss}, Q_{gen})	Reactive power flow unfulfillment ($Q_{unfulfilment}, Q_{gen}$)	Voltage Violation (V_{min}, V_{max})

Figure 54: Scope of the analysis (Source: ReserviceS project 2014 [135])

The **effectiveness of the reactive power - voltage control** is calculated as the maximum voltage variation obtained by means of the reactive power injection or withdrawal needed for both OPF solutions. Two elements will be analyzed:

- DV is the voltage variation (unit of measurement: pu)
- Q_{gen}: the reactive power provided (injected or withdrawn) by the generators (unit of measurement: Mvar)

The **impact of Q-V control on active power losses** is calculated as the maximum active losses reduction (referred to BAU DG1 scenarios) obtained by means of the voltage control defined with the collaboration of DG. Two elements will be analyzed:

- P_{loss}: Active power losses variation (unit of measurement: %)
- Q_{gen}: the reactive power provided (injected or withdrawn) by the generators (unit of measurement: Mvar)

The **reactive power flow constraint unfulfillment** is measured as the maximum deviation of reactive power flow requirement. Two elements will be analyzed:

- $Q_{unfulfillment}$ (unit of measurement: Mvar)
- Q_{gen}: the reactive power provided (injected or withdrawn) by the generators (unit of measurement: Mvar)

The **voltage violation** will be represented with the minimum and maximum voltage value in any node (V_{min},V_{max}):

- V_{min} is minimum voltage (unit of measurement: pu)
- V_{max} is maximum voltage (unit of measurement: pu)

Main results from the study on a MV network

Impact on voltage profile:

DG active power feed-in affects the voltage profile. This, added to DG forecast uncertainty introduces more complexity in the distribution system operation and limits DG hosting capacity. Q-V control provided by the generators may help to solve voltage problems caused by active power feed-in or any other reason but needs to be technically defined in a precise way. Figure 55 shows the results of the simulations for the different scenarios with different PV and wind penetration levels.

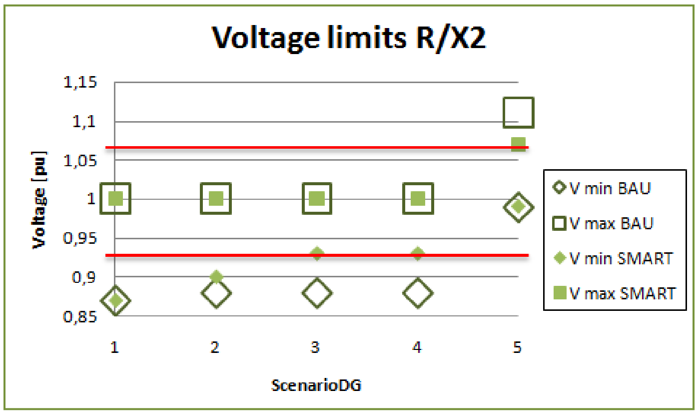

Figure 55: Results of the voltage violations analysis for the R/X2 MV network (Source: ReserviceS project 2014 [135])

The results show that even in the case of a weak network (R/X2), a smart voltage control approach based on Q set points sent to the MV connected generators can maintain the maintain the voltage within the defined boundaries if enough controllable capacity is installed. For instance, in the DG2 scenario, the five 200 kW PV systems cannot compensate the voltage rise at the MV bus bar.

Impact on P losses:

DG active power injection may cause a negative or positive effect on the active power losses depending on its penetration level. Q-V control provided by the generators is effective as long as losses reduction objectives are taken into account. On the other hand, if Q-V control is used to avoid voltage limits violations, losses may even increase.

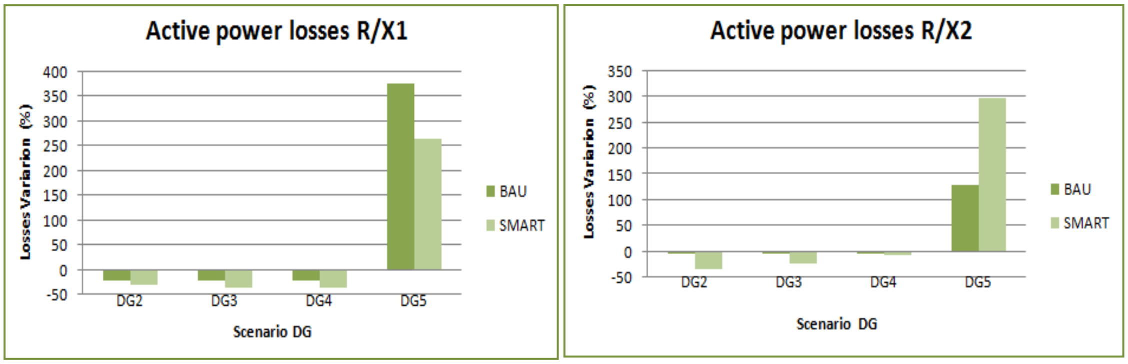

Figure 56: Impact of voltage control on active power losses (Source: ReserviceS project 2014 [135])

Q-V control effectiveness:

Q-V control demands a large amount of reactive power to be effective depending on the R/X ration as shown in Figure 57. The need for reactive power decreases as the dispersion of the resources increases.

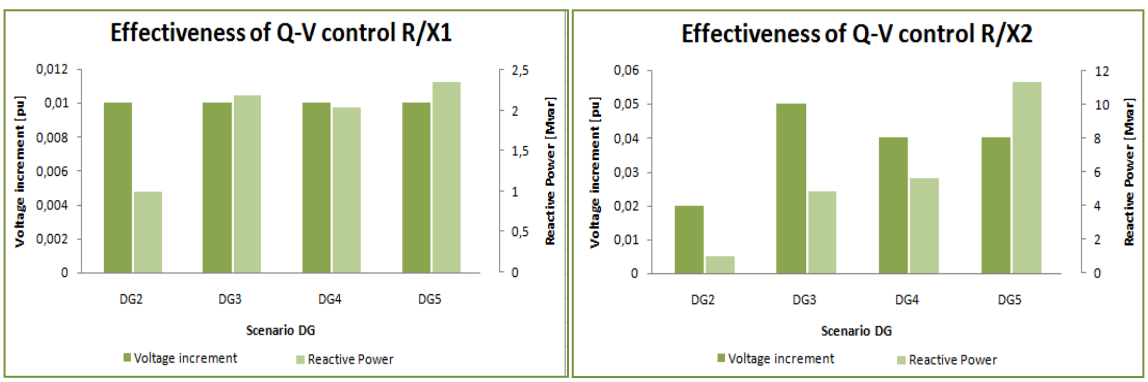

Figure 57: Effectiveness of Q-V control depending on the R/X ration and the scenario (Source: ReserviceS project 2014 [135])

Impact of reactive power flow restrictions on reactive requirements:

Fixing restrictions of reactive power flow at the HV/MV connection point (as for instance described in [134]) increases the demand of reactive power in the distribution system and causes an increase in active power losses in MV. Because of its dispersion, distributed generation's participation in Q-V control reduces the reactive power needed (by 20% in the case analyzed) to fulfil those restrictions.

Different solutions for different scenarios :

Voltage problems and possible solutions vary with network characteristics and load/generation scenarios. Therefore, a technical and economic analysis of each particular case must be carried out to identify the best solution and produce a customized approach for any considered case.

Main results from the study on a HV network

Impact of DG on reactive power exchange on HV-MV interface:

In Spain, grid codes forbid DSOs to export reactive power to the transmission system. Failing to comply with this rule results in what is considered as a "un-fulfillment". The significance of a un-fulfillment is based on the volume of reactive power exported to the transmission system.

The number of occurrences and the significance of un-fulfillments may increase or decrease with the level of penetration of DG, depending on the location of generation resources (distance to the TSO/DSO connection points).

When active power losses are minimized with a system approach (no constraints), the number and the size of unfulfillments may also increase or decrease. When DG (connected to HV and MV) are considered as reactive power resources, un-fulfillments can be reduced more as the DG penetration increases as shown in Figure 58.

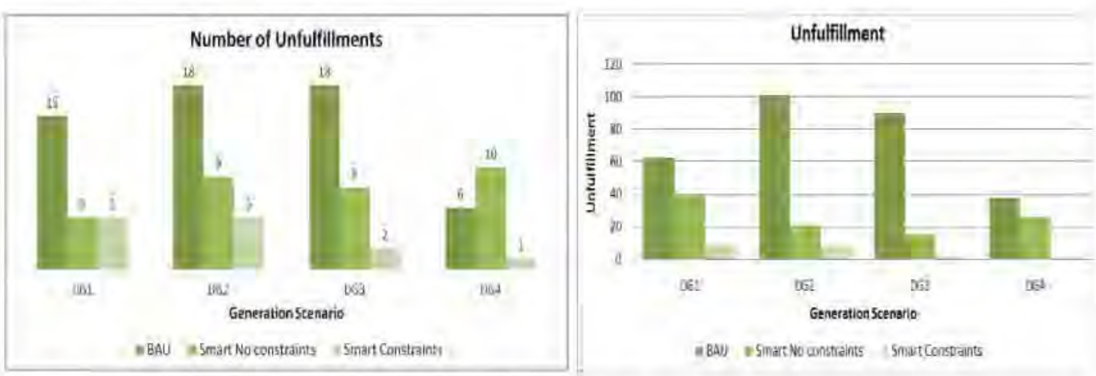

Figure 58: Number of occurrences and volume (in MVar) of unfulfillments (Source: ReserviceS project 2014 [135])

Impact of Q requirements on P losses:

For the analyzed penetration levels, DG's active power injection has a positive effect on the power active losses and that effect grows when Q-V voltage control provided is applied.

When reactive power flow requirements are fixed, power losses always increase despite the power losses minimization strategy as shown in Figure 59.

A close and flexible interaction between DSO and DG helps to reduce active power losses if new tools are deployed; e.g., new infrastructure, ancillary services, variable access contracts, etc.

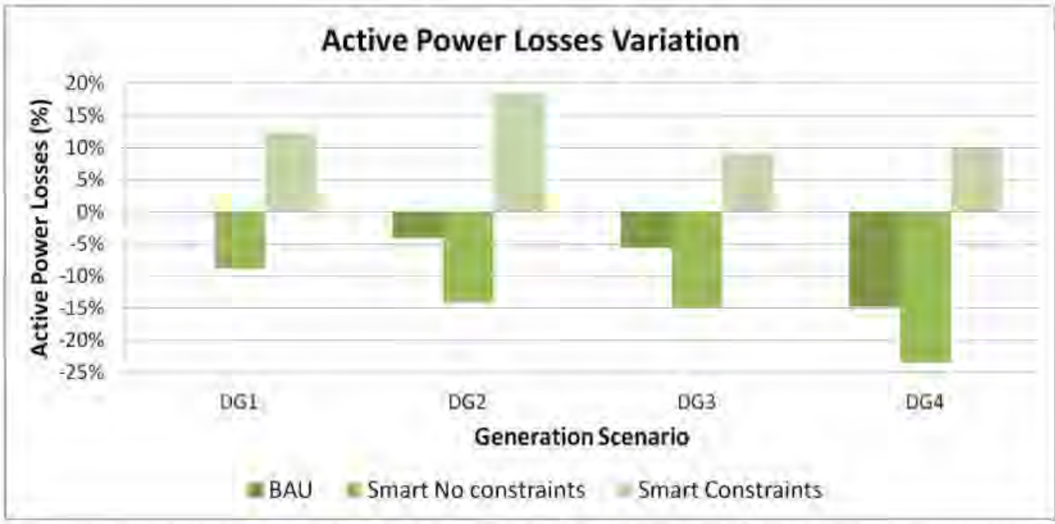

Figure 59: Active power loss variation for the different considered scenarios (Source: ReserviceS project 2014 [135])

Impact of Q requirements on reactive power generation:

Fixing restrictions of reactive power flows at the TSO/DSO interface increases the needed reactive power in the distribution system, causing inefficiencies.

Q-V control demands a large amount of reactive power to be effective. This amount highly depends on the location and dispersion of DG. Participation of DG in Q/V control helps to fulfil reactive power flow requirements at TSO/DSO connection points, but unavoidable high reactive power costs arise. Because of the dispersion and location of DG in this case study, the DG reactive power used is much higher than the avoided unfulfillment(s) in the analyzed cases.

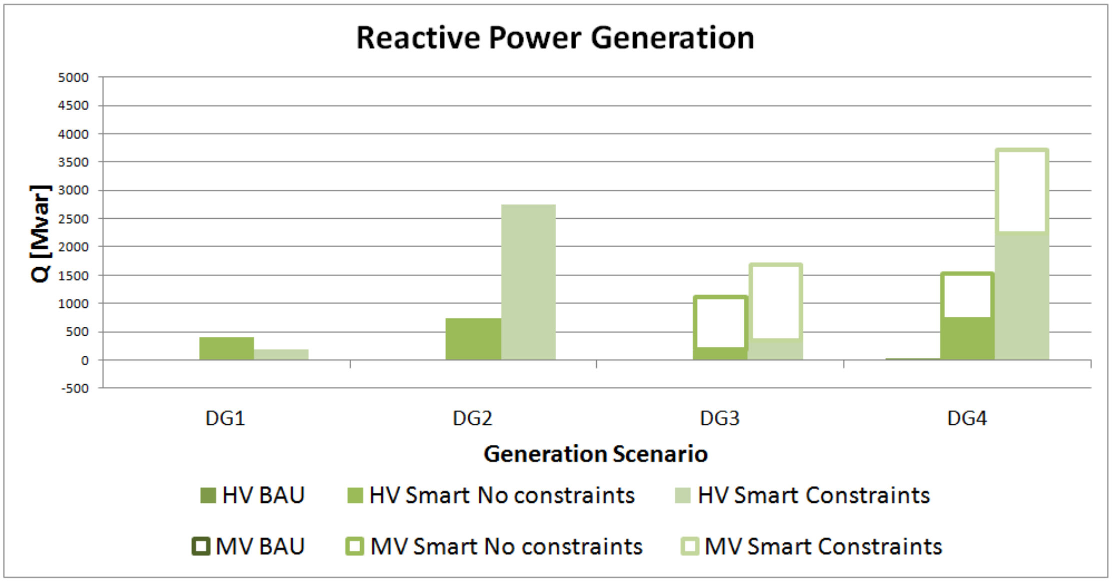

Figure 60: Reactive power generation for the different considered scenarios (Source: ReserviceS project 2014 [135])

Cost-benefit analysis of Q-V control in MV networks

Preliminary remark

All the results presented in this section are based on assumptions related to different simulations and not to any concrete project or existing network portions. The aim of this simulation is to show how the implementation of new functionalities could bring benefits at the system level, using smart grid technologies within a network configured as in the case studies presented before. As demonstrated in this analysis, the result is case dependent, varying significantly when applied to different scenarios.

Key findings

On one hand, costs occur due to new investments. The main assets considered in the cost benefit analysis are the following:

- Communication devices (e.g., routers, antennas, etc.)
- Devices to control DG active (Active Power Regulator or APR) and reactive power
- SCADA upgrade
- Grid infrastructure (e.g., cables, substations, etc.)

As shown in the case study, the proposed voltage control strategy can bring new benefits. The following benefits have been estimated and considered:

- Reduced operational and maintenance cost

- Deferred distribution capacity investments
- Reduced electricity technical losses
- Reduced outage times
- Reduced curtailment of DG.[13]

Moreover, Q-V control solution would enable an increase in DER hosting capacity so that indirect and external benefits, not monetized in this cost-benefit analysis, could also be taken into account; among these indirect benefits, one could consider the:

- Reduced CO_2 emissions and reduced fossil fuel usage
- Reduction of air pollution (particulate matters, NO_x, SO_2)
- Reduction of energy dependency,

The CBA results are presented in Table 45 [135] and are based on a 20-year net present value analysis with 2013 price references.

Two different case studies have also been considered with the same MV network, the same demand/generation forecasting, but different characteristics of the lines:

- "Weak" line scenario, where voltage problems cause outages and curtailment to be solved
- Present line scenario, where the absence of voltage problems drives loss minimization strategy.

Table 45: Results of the CBA Methodology Applied to Two Different Network Conditions. (Source: ReserviceS project 2014 [135])

REserviceS	Smart approach savings (Net Present Value)	Smart approach savings per agent			Smart approach savings per benefit				
		DSO	DG	Customers	Reduced operational and maintenance cost	Deferred distribution capacity investments	Reduced electricity technical losses	Reduced outages times	Reduced curtailment of distributed generation
Case 1- "Weak" MV network	29%	-35%	80%	-38%	-722%	98%	-70% (*)	38% (*)	100% (*)
Case 2- "Present" MV network	2%	16%	-100%	NA	-100%	-100%	20%	NA	NA
(*) Note.- losses increase because Voltage Ctrl is applied to fulfill voltage limits to avoid outages and DG curtailments									

As represented in Table 45, even though some external benefits have not been monetized, in both cases the investments and costs are compensated by the monetized benefits, which lead to a positive net present value . This means that the smart solution for DG integration

[13] Although curtailment is not allowed in Spanish regulation frame, it has been considered for this use case to extract information about benefits regarding curtailment.

is, for these two specific cases, cheaper than BAU. But different quantitative impacts are identified.

Not also the final result, but also the distribution of the investments and costs differs between the two cases, resulting on some cases on negative impact on the DSO or the DG side. Due to the differences between both cases, the distribution of savings among the different expected benefits also varies.

Switzerland

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Positioned in the center of Europe, Switzerland plays a leading role in the European electricity market. About 11% of the all the produced electricity in Europe flows through Switzerland, making it an important transmission country. Figure 1 illustrates the energy flows with neighboring countries for the year 2012.

The Swiss power plant infrastructure as a whole is characterized by a high level of capacity for peak load. This capacity covers the higher day-time consumption, in other words the peaks in demand in the morning, at midday, and in the evening, and evens out short-term imbalances between supply and demand. Peak load energy places higher technical demands on production, as either storage or flexible power plant deployment is required.

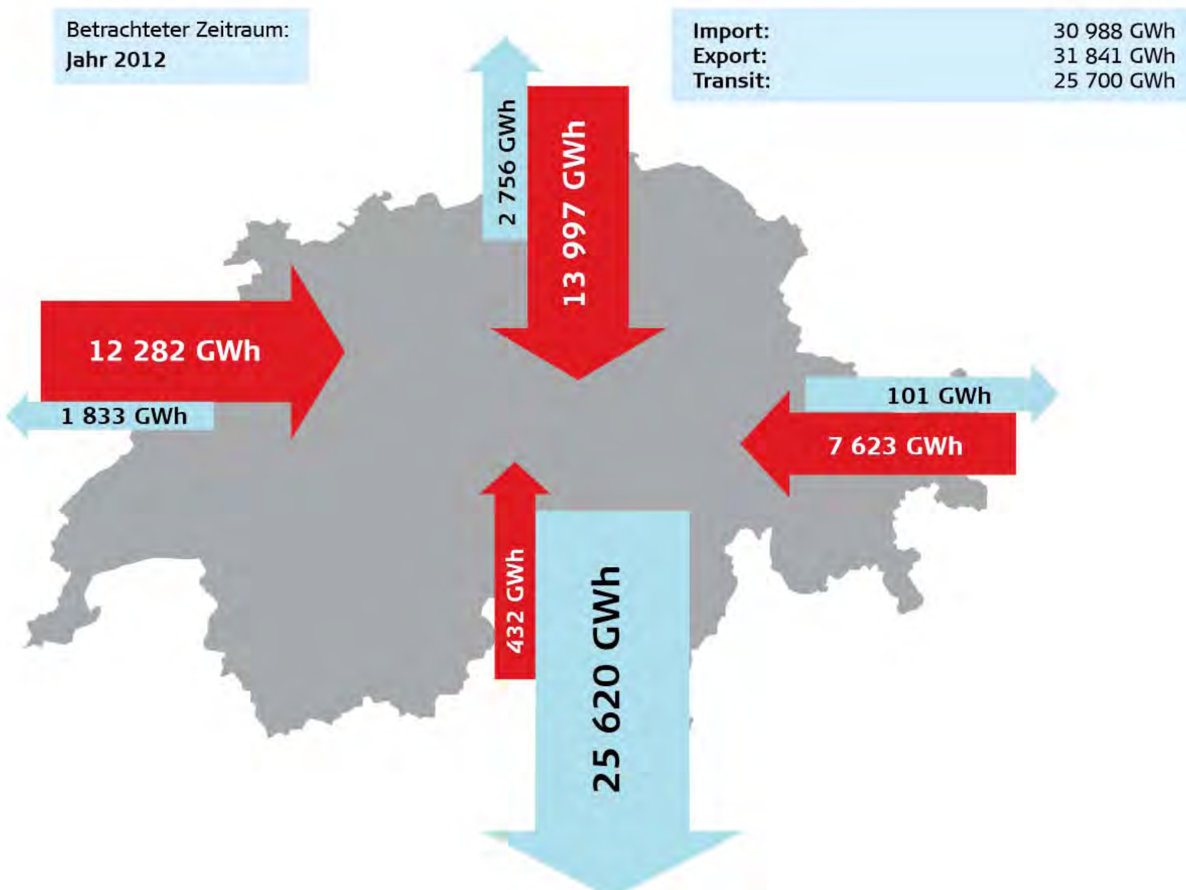

Figure 61: Overview of Swiss import/export and transmission in 2012 (Source: Swissgrid)

The National Distribution Grid Structure

The entire Swiss electrical grid covers a distance of 250,000 km.

The Swiss transmission and distribution grid consists of 7 different grid levels. Grid level 1 is the transmission grid. Levels 3, 5, and 7 are the distribution grids with varying voltages and levels 2, 4, and 6 are the intermediate transformation levels. A general overview of the Swiss electrical grid is given in Figure 62 below.

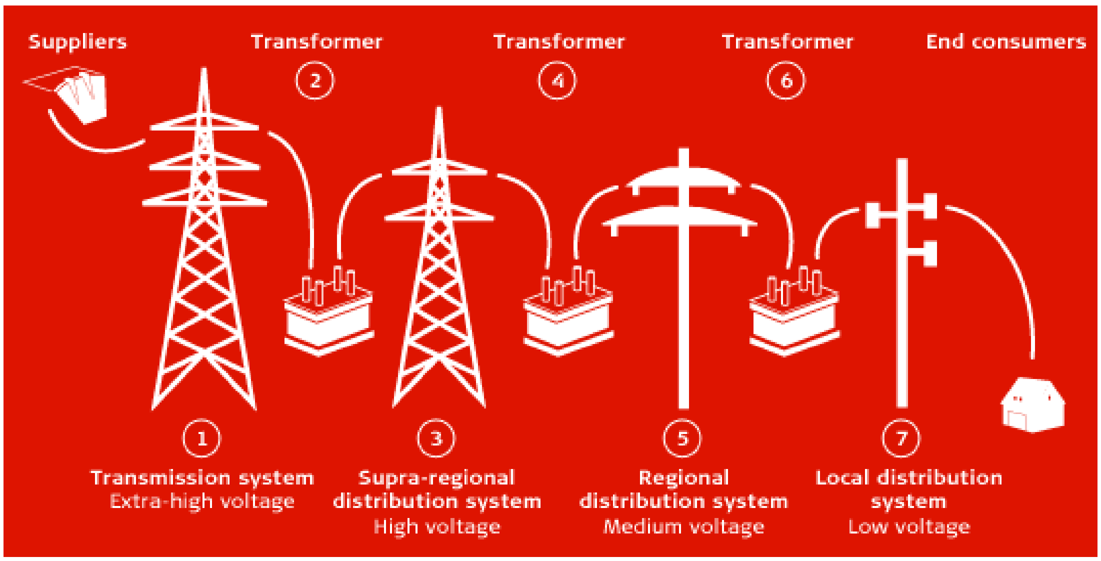

Figure 62: Overview of Swiss transmission and distribution grid (Source: Swissgrid)

The grid level **1** is an EHV **transmission** system that is fully owned and managed by the unique Federal TSO **Swiss grid** since 2013. The system operates with 380 kV or 220 kV to reduce the amount of energy that is lost due to transmission. It is used for transmitting, importing, and exporting electricity and distributing electricity to lower grid levels. The total span of the transmission system is 6,700 km.

The national **Distribution** grid system in Switzerland is very fragmented in terms of responsibilities and number of actors involved (for historical and structural reasons). There are remaining around **800** distribution grid managers (Source: Swiss grid internet site), who are acting on a territory of 47,285 km^2, each of them responsible for very various areas in terms of size, going from villages or towns up to inter-cantonal and regional scales.

The Supra-regional grid level (between level **2 to 4**) uses voltage levels from 150 kV to 36 kV and is used to supply energy to cantons, regional, and urban distribution grids as well as large industrial areas. The distribution grid represents the majority of the 250,000 km of the entire grid length and is 80% underground (Source: AES/VSE internet site / grid facts).

The supra-regional grid is owned and managed by several actors, often having also roles as producers and/or DSOs. Examples of major DSOs that may be named are EWZ, EKZ, BKW-FMB, Axpo, SIG, Groupe e, Romande Energie, REPower, CKW, FMV, EWO, AET, IWB, etc. All these actors own and/or manage various grid levels. Some actors are producers (e.g., Alpiq), some of them are not owners of their grid. Many system voltage levels can be found (e.g., 50 kV, 60 kV, 65 kV, 125 kV, 132 kV, 150 kV), and it must be expected that protection (mechanisms, relays performances) as well as network grounding (direct or inductive grounding…) are different according to levels and areas.

Grid level **5** is the MV grid. Theoretical nominal voltages range from 1 kV to 36 kV; in practice, the MV distribution grid mainly covers the standard range from 10 kV to 20 kV, with a few exceptions included in the larger range from 5 kV to 24 kV. The rated capacity of HV/MV transformers, in primary substations, is usually between 16 MVA and 63 MVA. The MV level is realized as a three-phase delta system consisting mostly of overhead lines in rural areas and underground cables in suburban areas. Meshed system topologies can be found in urban areas. In suburban and rural areas often a mixture of open- and closed-loop structures exist. In rural areas pure branch feeder configurations can be found. Typical interconnection customers are large industrial facilities as well as utility-scale generation units with a rated capacity of up to some MW.

The local distribution grid (level **7**) supplies small industrial areas and households with LV (<1 k). Many of the renewable energy power plants such as PV plants are connected to this grid level. The three-phase LV distribution level has nominal voltage 400 V/230 V. The rated capacity of Delta-Star MV/LV transformers, in “secondary” substations for energy supply to households, is typically from 250 kVA to 1,000 kVA while higher rates (typically 1600 kVA, 2,500 kVA) are possible for MV industrial users or energy producers. The nominal line-to-line voltage at LV levels is 400 V ±10% (steady-state voltage ranges defined by EN50160). The system is realized as a three-phase star system with a neutral conductor comprising mostly of underground cables. In rural areas overhead lines can still be found. Most of the LV grids consist of branch feeders only. For earthing TN-C systems, as defined by IEC 60364-1, are most common. Typical interconnection customers are private households and small commercial buildings.

Most of the Swiss PV capacity can be found at **LV levels.**

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

The structure of the main regulatory framework is described in Figure 63 below (Source: VSE/AES – association of Swiss electrical companies, which can be considered as the main representative of the electrical industry branch in Switzerland, and is also author of the main key documents).

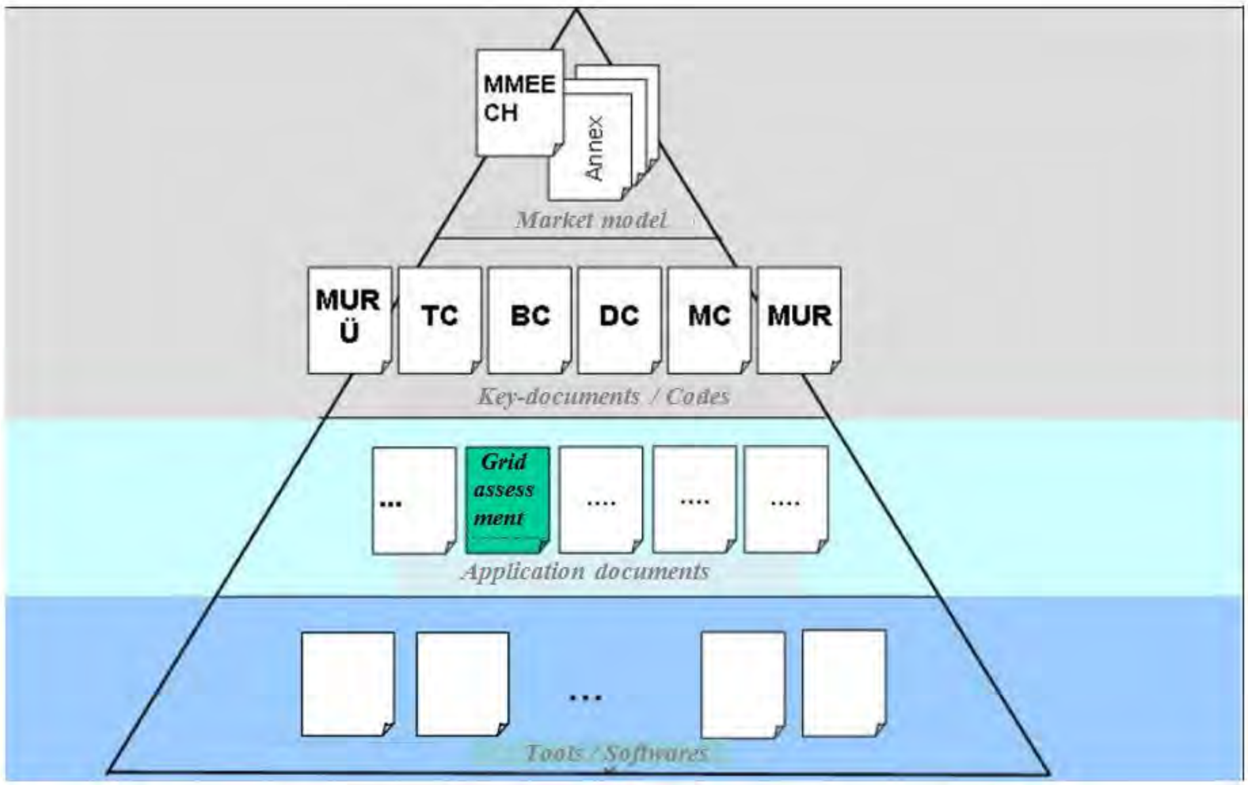

Figure 63: Structure of the documents for the liberalized market rules (Source: VSE/AES, Swiss distribution assessment)

While the laws and ordinances are directly made by federal council, the most important technical-regulatory documents giving technical details about various mechanisms and performances required are summarized below:

- MMEE CH: Market Model for electrical energy (Source and author: AES/VSE Current version: 2013). This document mainly gives the description of the market model, with details about all contractual relations required between each various electricity market actors, roles and responsibilities, etc.
- MUR T/ NNMUe: Transmission grid operation model (Source and main author: Swiss grid with AES/VSE collaboration). This document mainly describes legal relations with transmission grid, physical description of transmission grid, description of the transmission grid role and responsibilities, fares and tariffs related to electricity flux with transmission grid, etc.
- TC: Transmission Code (Source and author: Swiss Grid).This document has the most detailed requirements in terms of allowed static voltage fluctuations, PQ requirements, U/f chart, P/f chart, frequency control from Germany, FRT (Sources: chapter 6.5.2; 6.5.5) among other legal wordings concerning grid operation ancillary services and grid connection to transmission grid. Requirements for power plants' grid connection are applicable to 50 kV and above. This document will be referred below as TC 2010 (current version).

- Distribution Code: Distribution Code (Source and author: AES/VSE). This document defines technical principles for grid connection and operation for distribution grids in Switzerland (it has to be mentioned, however, that much technical information is fully delegated to local bilateral connection contracts) (e.g., position of the PCC, minimum and maximum permanent voltages, etc .). This document contains very little technical information relevant to PV (e.g., no UfPt, PQ chart, FRT, etc.). Requirements for power plants' grid connection are applicable to 50 kV and above. This document will be referred below as DC 2011 (current version).
- Others: BC (Balancing Concept), MC (Metering Code), etc.

There is **no specific code** with power system technical requirements and legal binding force that was made so far made specifically for PV.

The following documents must, however, be mentioned:

- "**Technical Rules for the assessment of Network Disturbances**" (commonly called "DACHZ") which contains both some recommendations how to assess potential grid disturbances and/or several technical requirements (e.g., short-circuit power, harmonics, maximum steady-state voltage rise, voltage imbalance, flickers…) (Authors: Joint collaboration of four associations: VEÖ from Austria, AES/VSE from Switzerland, CSRES from Czeh Republic, VDN from Germany).
- **ESTI Nr 233.0710 Solar PV:** This Swiss Norm is mainly containing reference to applicable other norms (e.g., EN) and existing legislative documents applicable. It focuses on safety, EMC, and power quality (e.g., earthing and neutral concepts and related safety measures, reference to EN norms for harmonics, etc.).

Important remark about ENTSOE draft grid code current work and its relation with Switzerland:

Some of the most impactful and most detailed technical grid code ever made to be applicable for PV and other renewable sources is currently ongoing in Brussels for application throughout Europe, via the recent current network codes developments (e.g., Requirement for generators from the "connection codes package," 24 January 2012, which will be named "ENTSOE 2012" in this document).

Even though the Swiss grid is a member of ENTSO-E, gathering 41 TSOs from 34 countries in Europe, the Switzerland federal state has special status in relation with this project, and all technical requirements will have to be subject to Swiss laws to become legally binding and applicable in Switzerland (Source: Network code for requirement for grid connection applicable to all generators, FAQ, 24 January 2012, chapter 2, ENTSOE internet site). The application of ENTSOE 2012 technical requirements to PV and other electrical power plants is therefore uncertain at the time of this report.

ENTSOE will become legally binding to all countries in Europe and it will have direct impact to all TSOs, DSOs, PV manufacturers, and the whole electrical industry in general.

Review Answer 7 of the FAQ to learn more about the European Union position concerning the relation between domestic PV and the transmission grid, and Answer 3 of the FAQ to learn about the Switzerland case (Source: ENTSOE internet site, Network code for requirements for grid connection applicable to all generators Frequently Asked Questions, 24 January 2012).

Required Control Capabilities by Photovoltaic Systems

As of today there is **no developed and detailed specific "capability and performance"** requirement(s) directly applicable to PV in distribution grids.

Transmission requirements may however give relevant information about the **desired** performance of the transmission grid in Switzerland, and may have potential implications and direct and indirect links with distribution, even for PV in households. The following list, while non-exhaustive, may give an overview of the requirements' status at all levels, to show potential future candidate requirements:

- Electrical point of reference: No fully common terminology is used despite references of injection point or connection point in the distribution grid code (Source: Chapter 6.3 from DC).

- Steady-state capabilities (voltage/frequency/power/time): There is no such information at the distribution level.

  A steady-state requirement is, however, present in the transmission grid code with potential application to 280 kV and 380 kV. It has to be noted that, at the 225 kV level, the following is required:

  - A degree of over-magnetization of 1.21 for 10 minutes (it would be interesting to check if all equipment in the Swiss transmission grid is standing such level);
  - A continuous rated power for 0.95 pu voltage; and
  - Maximum P reduction of 20% during frequency drop down to 47.5 Hz is required at the 225 kV level (Source: Chapter 6.5.2 from TC 2010).
- Frequency range: Minimum frequency of 47.5 Hz and maximum frequency of 51.5 Hz is mentioned in Figure 62 below. A continuous rated power for frequencies down to 49 Hz for 15 s is potentially applicable for 50 kV and above (Source: Chapter 6.5.2 from TC 2010).

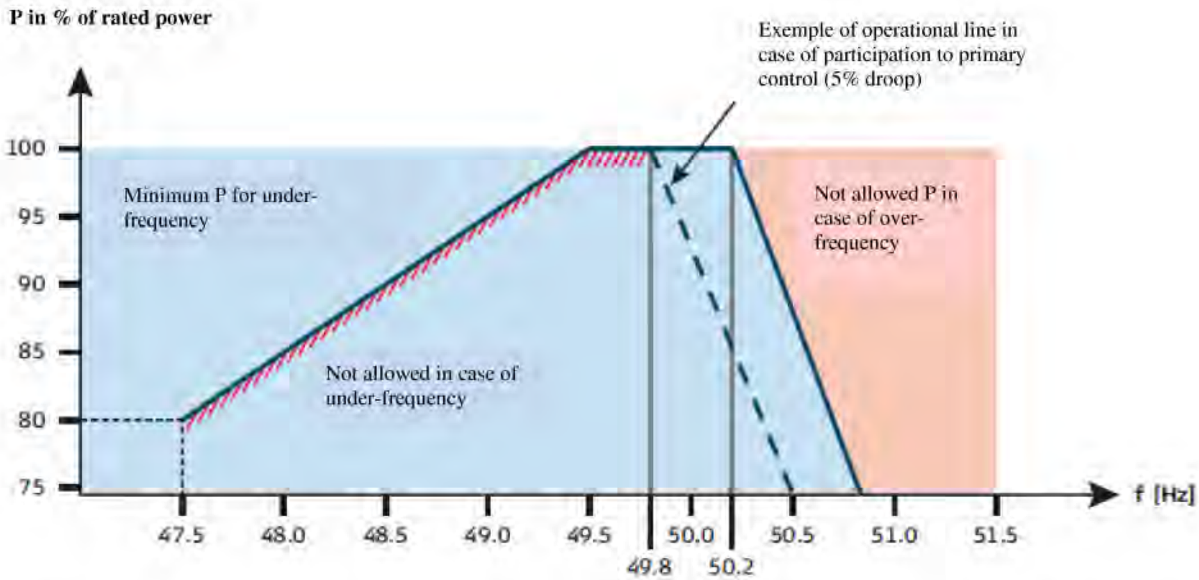

Figure 64: P requirements applicable to transmission grid (Source: chapter 6.5.2 from TC 2010).

- PQ capabilities: **No requirements are expressed for PV in distribution**. It has to be mentioned that while TC 2010 mentions a “triangle” PQ chart from cos phi 0.925 (injection/over-excited) to cos phi 0.950 (absorption/under-excited). ENTSO-E is already introducing a “full square” PQ chart with a larger range (no load Q absorption/injection capability), applicable at transmission.

- PQ requirements: Maximum steady-state voltage rise is 3% in LV and **2% in MV** at "any point of connection” (Source: DACHCZ, page 137). Harmonics (individual, THD, currents, and voltages), flickers (Pst, Plt) are mainly limited to the values required in EN 50160 and 61000-2-2.

- Rate of change of frequency is **not specifically defined** nor applicable to PV in distribution, but the figure below illustrates potential requirements for plants connected to the transmission level (0.09 Hz/s) (Source: Chapter 6.5.2 from TC). ENTSOE is planning that small PV shall withstand ROCOF of 2 Hz/s, with frequency to be measured using 1,000 ms average (Source: Article 7, b, ENTSOE 2012)

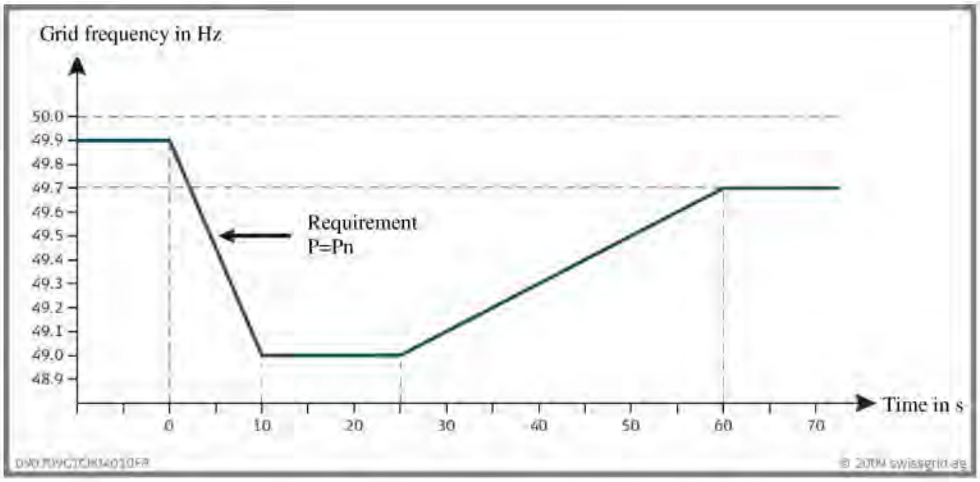

Figure 65: P delivered to be guaranteed from p power source connected to transmission grid (Source: chapter 6.5.2 from TC 2010).

- Islanding, start stop requirements, etc.: There is **no requirement known in Switzerland**. Note that ENTSOE 2012 is requiring a logic interface to enable to disconnect the power plant from the network, operable **remotely** (Source: Article 7, d, ENTSOE 2012).

- P control performance and P control modes: There **are no such requirements or details**.

- Q/cos pi /U control: There **are no such requirements or details known in Switzerland** (apart from the PQ capability chart from TC 2010 mentioned above).

- FRT requirements: No requirements are expressed for PV in distribution but it should be noted the Transmission Code refers to a FRT (Source: CChapter 6.5.6 from TC 2010). Note at this stage that FRT is first of all needed "to avoid that losing unit(s) or aggregated production larger than the largest unit, to prevent larger regional voltage collapse, or preventing collapse of important and sensitive transmission corridor" (Source: "European Grid Code Development – the Road towards structural harmonization" Authors: Frans Van Hulle, Peter Wibaek Christensen). The presence of the FRT itself is therefore **questionable** in a distribution code for small PV (e.g., Adding instead some examples of short-circuit behaviors to be tolerated? With a maximum short-circuit contribution from PV in pu at PCC?).

- Frequency control: A requirement from Germany is expressed in the Swiss Transmission Code (Source: chapter 6.5.5 from TC 2010).

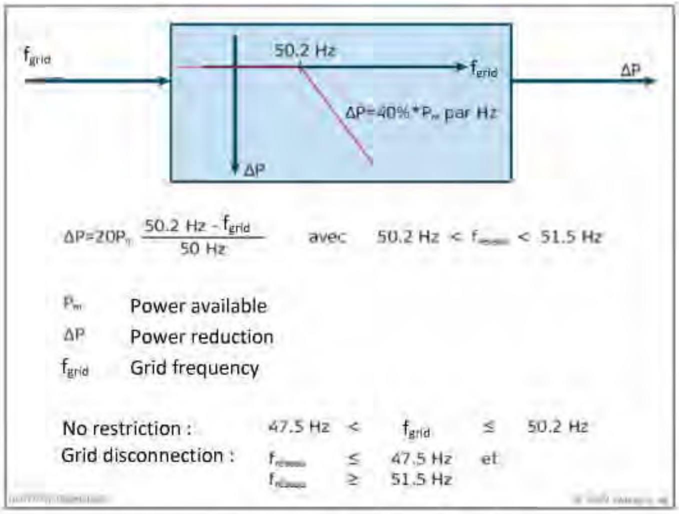

Figure 66: Main figure for frequency control (Source: Chapter 6.5.5 from TC 2010)

- It has to be noticed that ENTSOE 2012 instead gave room to flexible values, by setting thresholds from 50.2 Hz to 50.5 Hz and droop to be agreed between 2% and 12%. It is therefore assumed that national grid conditions will impact the efficiency of frequency control and specific values may be relevant to be investigated.
- Others: Inertia, damping, communication and control interfaces (e.g., forecast and meteorological information, etc.), simulation models (black box, etc.), performance verification aspects (measurements, etc.): There are **no such requirements** or details today.

Case Studies for High PV Penetration Scenarios

With an energy share of only 0.5% to 1%, solar electricity plays only a minor role in the Swiss electricity mix. Large-scale high penetration scenarios do not yet exist. In this case study, a high penetration scenario in the area "Luchswiesenstrasse" of Zurich was investigated using load flow simulations with high resolution irradiation profiles and load patterns. Definitions:

- **PV penetration in %**: Yearly electric energy produced by PV power plants divided by yearly energy consumption in the same area.
- **PV hosting capacity**: Maximum possible PV penetration.

Grid overview

Table 46 gives an overview of the most important facts and figures of the grid. The grid topology is shown in Figure 67.

Table 46: Facts and Figures of the Grid

Number of energy meters (corresponds roughly to the number of households)	1550
Number of grid connections	111
Number of main cables	28
Maximum load	1,300 kW
Average yearly energy consumption	5,200 MWh
Rated transformer power	2 x 1,000 kVA
Grid voltage	230 V / 400 V

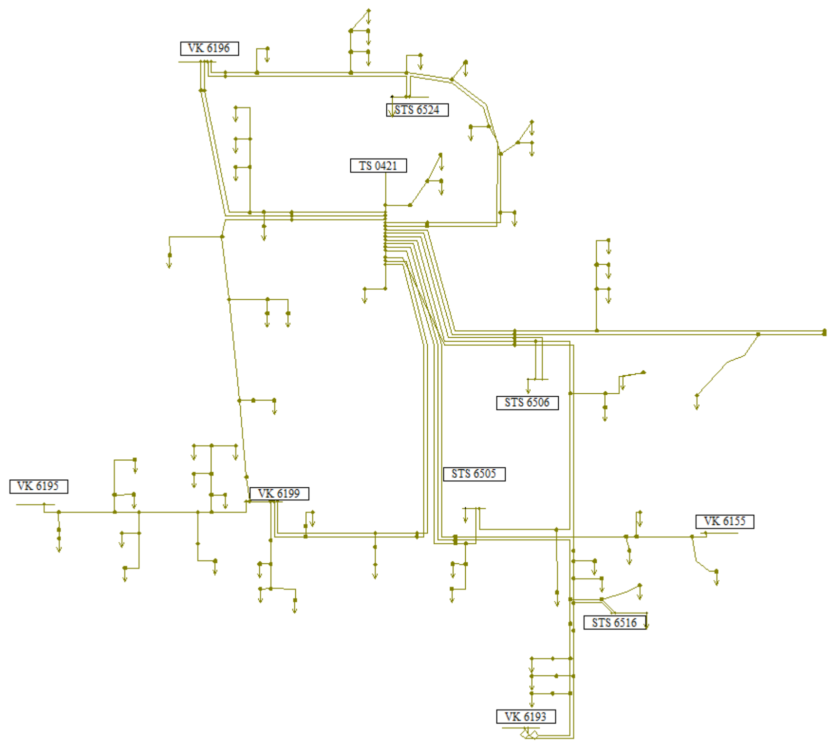

Figure 67: Grid topology of the investigated grid area “Luchswiesenstrasse”

Roof capacity for PV systems

The roof capacity of the investigated area is roughly 3,600 kWp, resulting in an energy yield of 3,270 MWh per year. This corresponds to 67% of the annual electricity consumption of the area. To reach this amount of PV, every roof needs to be completely covered with PV panels. From today's perspective, this seems to be unrealistic. However, it gives an upper limit, which is used as the maximum PV penetration in this study.

Simulation method

As most of the loads in the grid are domestic households, the loads are modeled using high-resolution load profiles (Source: Distribution Grid Analysis and Simulation with Photovoltaics (DiGASP), Christof Bucher et al., PV+Grid, PV ERA NET). The output of the PV systems is modeled using stochastic irradiance profiles developed in the same project as the load profiles.

The load flow computation is done using MATLAB and the Matpower toolbox. The temporal resolution of the simulation was chosen between 1 and 15 minutes, depending on the type of simulation. The grid is modeled using the NEPLAN model of ewz, which takes into account both the impedance and the reactance of the cables. For different grid integration measures, the PV hosting capacity of the grid was computed. The grid voltage rise was thereby the major restriction for further increase of the PV penetration.

To compute the PV hosting capacity of the grid, all roofs are homogeneously equipped with PV systems. The size of the systems is chosen proportionally to the roof surfaces and gradually increased until the voltage at any point in the grid exceeded the permitted voltage tolerance band. The same procedure is applied to find the thermal current limitation of the grid.

Results

The results are summarized in Table 47.

Table 47: Results Summary of the Case Study

	Simulation Method	Remark	Result
1	**DACHCZ: no measures**	Standard method to calculate if a particular PV system can be connected to the LV grid (max 3% relative voltage rise in LVDG)	PV hosting capacity = 370 kWp (6%), voltage limit. Thermal current limit allows 965 kWp (26.8%)
2	**Correlation with load**	Similar to 1. Not the relative but the absolute voltage investigated. PV rises the voltage, loads lower the voltage.	PV hosting capacity = 1,000 kWp (17%), voltage limit. Thermal current limit allows 1,200 kWp (33.5%)
3	**RPC: Reactive power control**	Cos(phi) is reduced to 0.9 (cos(phi) fix)	The PV hosting capacity can be increased by 20% to 450 kWp (simulation method 1) and 1,200 kWp (simulation method 2).
4	**APC: Active power curtailment**	Two curtailment scenarios: 70% AC/DC-ratio, energy loss of 3% 50% AC/DC -ratio, energy loss of 15%	41% more PV hosting capacity 85% more PV hosting capacity
6	**Storage**	Every power plant gets an energy storage of 1 h rated PV power 4 h rated PV power	Ca. 50% more PV hosting capacity Ca. 200% more PV hosting capacity

7	**DSM: Demand side management**	Assumption: Hot water Boilers can be switched on during midday.	30% - 70% more PV, depending much on the design.
8	**OLTC: On Load Tap Changer transformer**	Reducing the voltage at the transformer by 3%	100% more PV hosting capacity. Thermal current limit reached in some cases.

Figure 68 shows the voltage histogram for one year, using a temporal resolution of 5 minutes. The first voltage violation occurs between scenario 3 (PV pen. = 13.4%) and scenario 4 (PV pen. = 20.1%), while the first line overload occurs only with scenario 6 (PV pen. = 33.5%).

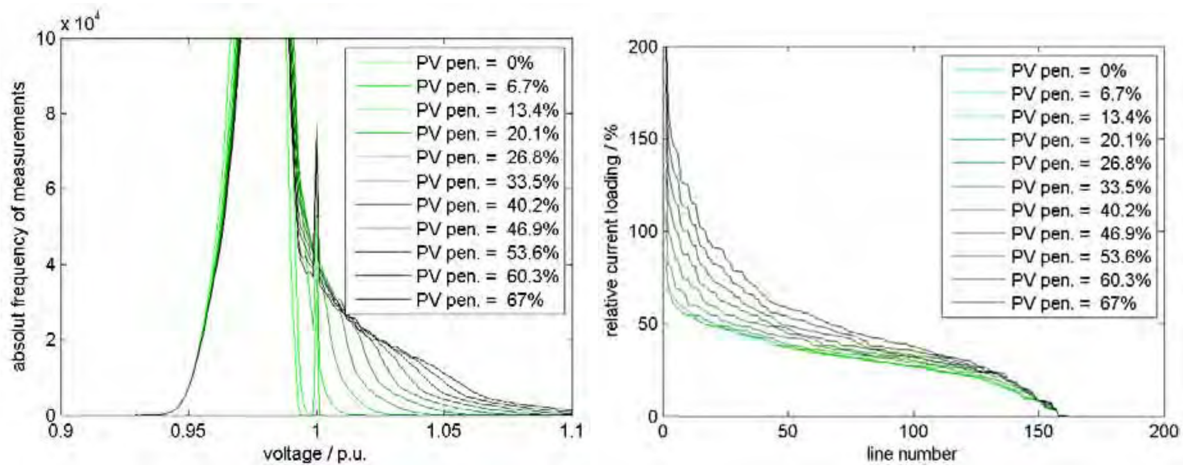

Figure 68: Voltage histogram and maximum current loading for different PV penetration scenarios

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

In 2012 PV production in Switzerland fed 340 GWh of energy into the grid (Source: BFE/OFEN). This is more than double the amount produced in 2011 (160 GWh). Compared to the country's overall energy production, solar power contributed a mere 0.5%. It is also estimated today that energy produced in 2013 would have also doubled, reaching 1% of the energy mix (Source: Swiss solar internet site).

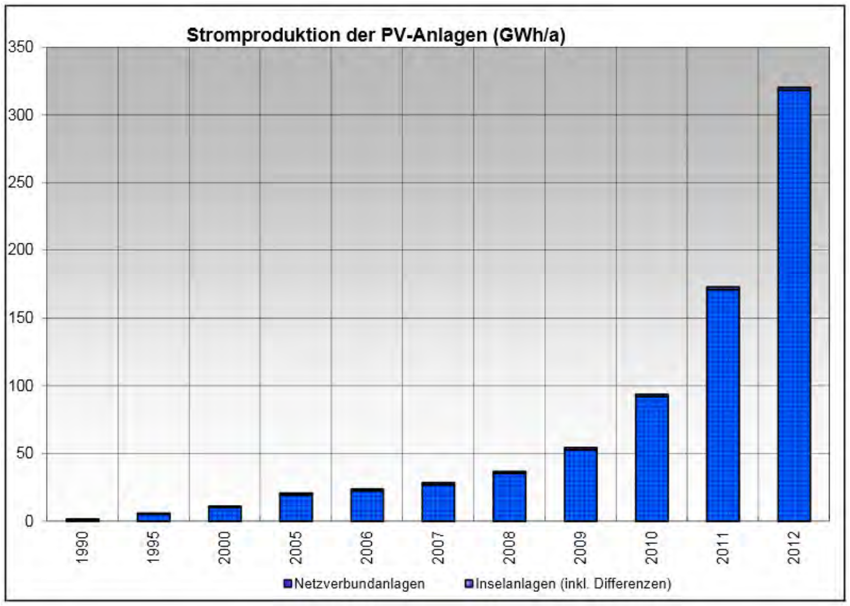

Figure 69: PV energy production in Switzerland since 1990 (Source: Swissolar)

Even though PV in Switzerland today represents a small part of the energy mix (0.5% to 1% of the produced electricity), it is growing fast. It is therefore strongly suggested in the present document to analyze grid needs in anticipation, to observe the requirements from a panel of countries' grid codes, and to investigate potential opportunities for PV performance.

Section 2.10.3 above gave the following indications about the potential grid needs and/or potential capabilities that could be investigated:

- Frequency range
- Frequency control
- Islanding
- P control
- Forecast and communication.

PQ capabilities:

- Steady-state voltage control
- Signals and control.

Taking into account the very fragmented nature of the distribution grid management structure in Switzerland (approx. 800 DSOs and one TSO), Switzerland's big challenges will be, among others, to develop robust, simple, and generic requirements to be relevant both for the whole grid and for the PV industry.

The Tk8 committee from «electrosuisse» is likely to work on potential evolution of the «DACHZ » (Source: internet site of electrosuisse) or potential other norms or standards, and ESTI is also working on its norm applicable for PV. It can only be assumed that a working group will be raised in the near future to work on the requirements mentioned in the present document.

The following two projects are to be mentioned:

- VEIN project, led by consortium VEiN (Contact: Samuel.plaffen@misurio.com): This project aims to exploit the flexibility of a pool of thermal storage devices for balancing the electrical grid. A highly intelligent system aggregates the existing flexibility, generates best bids on behalf of the system operator, and guarantees an optimal overall operation. The project investigates economical, physical, and legal requirements that guarantee sustainable implementation (http://www.vein-grid.ch/index.html).

- Cooperation D-A-CH Smart Grids: The cooperation D-A-CH Smart Grids is based on a Memorandum of Understanding between the three neighboring countries in Germany, Austria, and Switzerland. The main goal of this effort is to closely collaborate in the field of R&D and dissemination in the emerging smart grid area. To coordinate the work of specific cross-cutting topics, four task forces have been established.

United States of America

Author:

Barry Mather[1]

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National Distribution Grid Structure

Figure 70 shows a simplified picture and electrical one-line diagram of the entire electrical power system typically used in the United States. Traditionally, generation has been located relatively distant from the bulk of electrical load requiring power produced by generators to be delivered via transmission, subtransmission and distribution systems to the end users. Some large-scale industrial customers connect to the subtransmission system directly, but the majority of electrical power consumed is delivered through the distribution system. Generally, voltage levels below 50 kV are considered to be distribution systems whereas subtransmission systems typically have operating voltages below 100 kV but above 50 kV. Subtransmission systems are often employed in urban areas with the subtransmission system using either a networked or ring type architecture to improve the power delivery reliability of the system. Distribution systems in the United States are typically radial in nature but often have built-in flexibility for circuit reconfiguration (e.g., switching segments of the circuit or an entire circuit to another distribution circuit) to accommodate outage recovery efforts and to allow the distribution utility to isolate portions of a distribution circuit for equipment maintenance without causing an outage on the entire distribution circuit.

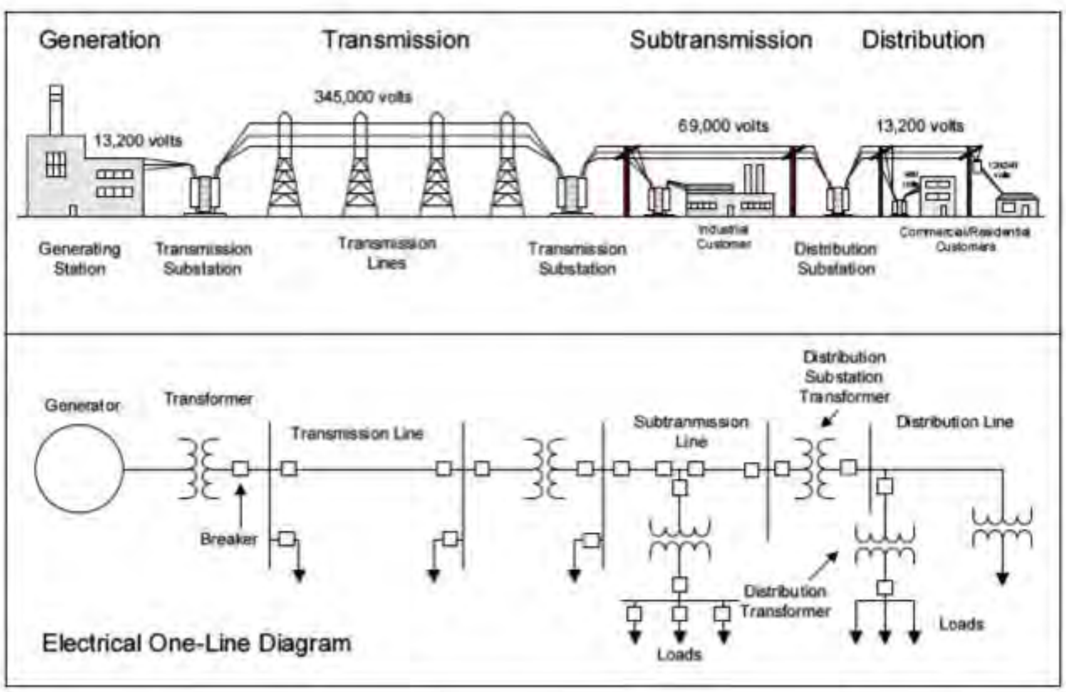

Figure 70: Typical simplified electrical power system structure in the United States

Typical distribution circuit nominal operating voltages are 34.5 kV, 33 kV, 24 kV, 13.8 kV, 13.2 kV, 12.47 kV, 12 kV, and 4.16 kV. Many more nominal operating voltages are used by individual utilities but are typically within the range of voltages shown above. For instance, a utility may use equipment designed for 12.47 kV nominal operating but will operate with a nominal distribution circuit voltage of 12 kV resulting in a 3.7% lower per unit voltage. There are approximately 3,000 distribution utilities in the United States—consisting of about 200 investor-owned utilities (IOUs), 840 electrical cooperatives, and the remainder being municipal utilities [138]—and each system is planned and operated in a different way. This fact, added to the cultural and climatic diversity present across the 50 states that comprise the United States, makes it is easy to see that there is a lot of variation in the topology of the distribution circuits. Taking this into account, the following discussion attempts to present a description of typical distribution system topology.

Typical Distribution Circuit Length and Voltage Level:

Most distribution circuits in the United States are MV circuits with nominal voltage ranges between 14 kV and 12 kV. Lower voltage circuits (i.e., 4.16 kV) are generally being phased out and upgraded when possible. Higher voltage circuits (i.e., 34.5 kV) are not common but are representative of circuits that may have been built relatively recently and likely serve relatively rural areas (long circuit length) with significant load.

The length of a typical 15 kV Class (i.e., 12.47 kV) distribution circuit depends heavily on the density of the load it serves as well as the types of loads it serves, such as industrial, commercial, and residential. In areas with higher load density a circuit may be as short as 3 miles long. In very rural areas and for distribution circuits that serve mainly rural residential loads, a distribution circuit may be 30 or more miles long. The vast majority of distribution circuits are bracketed by the two examples given above.

Typical Distribution System Equipment and Controls:

Distribution system equipment often used in the United States includes: load tap changing transformers, voltage regulators, fixed and controlled capacitor banks, and manual and remotely controllable pole switches. Load tap changing transformers allow the voltage of the distribution circuit or circuits supplied by a single substation transformer to be regulated within a desired tolerance. Line drop compensation (LDC) is often used which effectively regulates the voltage at a predetermined point on the distribution circuit down the line from the substation. Voltage regulators operate in much the same was as load tap changing transformers except that they can be located anywhere on the distribution circuit. Voltage regulators have controllers very similar to load tap changing transformers and often implement LDC as well. Capacitor banks are used by utilities to supply some or all of the reactive power requirements of the loads operating on the distribution circuit. Fixed capacitor banks are sometimes used if reactive power support and/or voltage support is needed on the circuit at that specific location at all times of the day. Otherwise, controlled capacitor banks are employed to connect and disconnect the capacitor from the distribution circuit when appropriate. Pole switches are used to reconfigure the distribution circuit and/or are used to isolate sections of the distribution circuit for maintenance. Some utilities use remotely controllable pole switches to enable automatic or remotely controlled distribution circuit restoration. Generally, manually operated pole switches are much more common.

Additionally, the substations that supply the distribution circuits often have Supervisory Control and Data Acquisition (SCADA) systems that enable remote visibility of distribution circuit operation (voltage level, circuit loading, and substation breaker configuration are typical) in near real-time. Voltage regulators, controlled capacitors, and remotely controlled pole switches are also often connected to the substation SCADA system and typically communicate their current status to remote operators. These SCADA-connected devices that are located outside of the distribution substation, often many miles from the substation, connect to the utility SCADA system most typically using application-specific radio communication links.

Typical Voltage Regulation Scheme:

Many different methods are used to regulate the voltage along distribution circuits within the United States. Some utilities typically use only load tap changing transformers located at the substation and then size the distribution circuit conductors so that no additional voltage regulation is necessary. Other utilities use voltage regulators, particularly on long distribution circuits, to keep the voltage profile of the distribution circuit within the acceptable voltage range as defined by ANSI C84.1 range A [139]. Other utilities rely on fixed and controlled capacitors to raise circuit voltage when necessary effectively regulating the voltage profile along the entire distribution circuit. Many more utilities use a combination of load tap changing transformers, voltage regulators, and fixed and controlled capacitors to regulate the voltage along a distribution circuit and manage reactive power flows through the circuit.

Interconnection of Photovoltaic Systems: Technical and Regulatory Framework

Technical Framework:

In the United States, the most common technical requirements specifications document used in regards to the interconnection of distribution-connected PV systems is the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems [140]. This document is often the technical requirements document specified by utility regulators (see next section) in respect to the interconnection of any distributed resource with a distribution system. IEEE 1547 describes the technical requirements for interconnection at the point of common coupling of the distributed resource. For PV systems this is most often the low side of a distribution transformer owned by the distribution utility. A related document, UL 1741 Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources [141], specifies the equipment requirements and how they need to be tested and certified.

Recently, an amendment to IEEE 1547, IEEE P1547a [142], has been under development. The amendment is considering technical requirement changes for the active regulation of point of common-coupling voltage, over- and under-voltage trip levels and times, and over- and under-frequency trip levels and times.

Regulatory Framework:

Distribution utilities are regulated in a variety of ways in the United States. Investor-owned utilities (IOUs) are typically regulated by state-level public utility commissions (PUCs). All IOUs within a state are all regulated by the singular state PUC. Electric cooperatives and municipal utilities are usually regulated or advised by representatives from their constituents. While many states have aggressive renewable portfolio standards (RPSs) that encourage the development of renewable energy resources such as PV energy, it is not a general requirement that all PV systems must be interconnected. Generally, PV system installers or owners file a formal request for interconnection, and this request is processed in a prescribed and regulated manner. Figure 71 shows a simplified flow diagram of the typical steps in a formal request of interconnection.

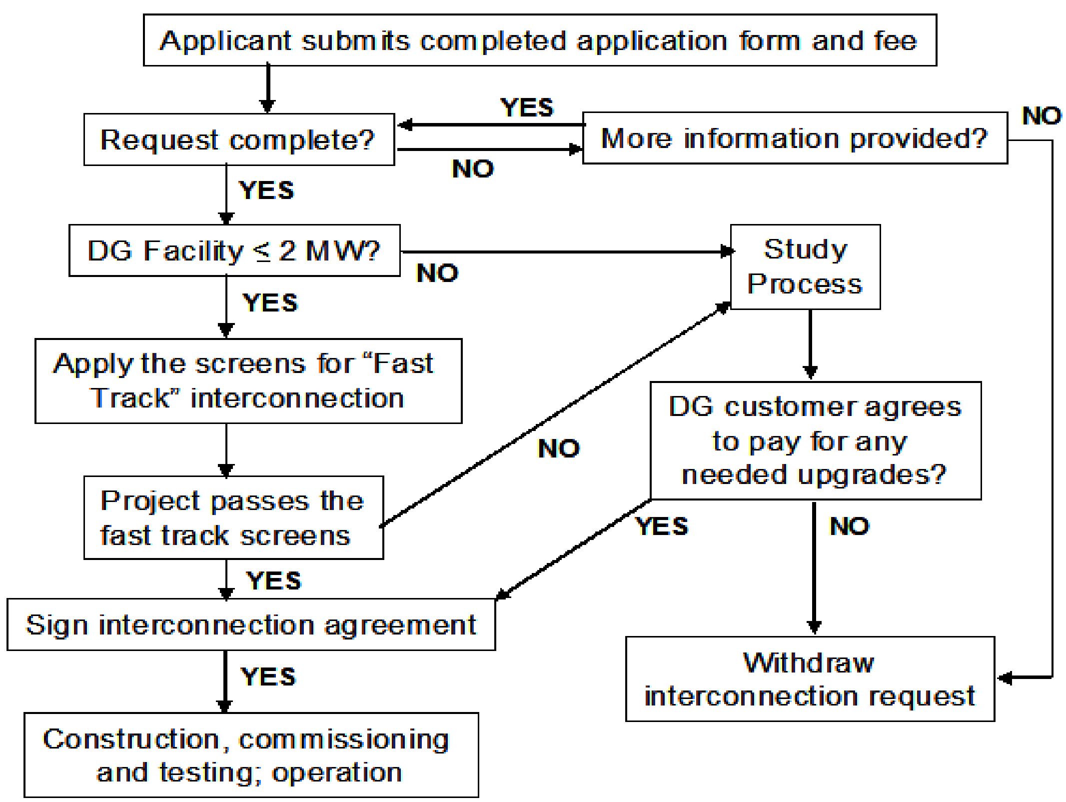

Figure 71: Typical simplified flow diagram of the interconnection process of interconnecting DG

In the typical interconnection process, as mandated by the utility regulator, there are usually a number of screens that are applied to the interconnection request to filter out requests that will have little to no impact on the distribution system to which they interconnect. These are often based on the total nameplate rating of the generating facility and the voltage which it interconnects. These are often referred to as the "fast track screens." If a project fails one of the fast track screens, a study is completed (usually at the cost of the PV developer). This study is meant to determine the impact the interconnected system will have and also to determine any upgrades required to accommodate the requested interconnection. If upgrades are required, they are to be paid by the PV developer.

Required Control Capabilities by Photovoltaic Systems

As per IEEE 1547 distribution-connected PV systems are required to implement considerable autonomous control designed to allow the system to operate in coordination with the rest of the electrical power system. These controls include under- and over-voltage trip points and times, under- and over-frequency trip points and times, and the requirement that the inverter disconnect from the utility within 2 seconds if a local utility island is formed. IEEE 1547 does not specify how these controls are to be implemented but instead specifies the required performance of the overall system at the point of common coupling.

In addition to IEEE 1547 requirements some U.S. utilities have required additional control capabilities specifically for some PV systems. These include the ability to remotely turn off or curtail the real power output of the PV system by the interconnected utility. Additionally, to mitigate the potential for the creation of utility islands, some PV systems have been required to incorporate a direct transfer trip (DTT) communication signal into their system controls that quickly disconnects the PV system from the electric power system if the DTT signal indicates that the substation breaker feeding the distribution circuit that the PV system is interconnected to has opened. This type of control aims to both prevent the formation of utility islands and to better coordinate PV system operation with distribution circuit recloser operation.

Case Study for High PV Penetration Scenarios

The U.S. Department of Energy (DOE) and the California Public Utility Commission (CPUC) have been activity funding a number of research projects focusing on the technical challenges of high-penetration PV grid integration through their respective SunShot Initiative [143] and California Solar Initiative (CSI) RD&D Program [144]. One of the projects funded by both programs is the "Analysis of High Penetration Levels of PV into the Distribution Grid in California Project" operated in collaboration between the National Renewable Energy Laboratory (NREL) and Southern California Edison (SCE). The high-penetration PV case studies, one based on an existing high-penetration PV distribution circuit and one focusing on a model-based assessment of the impacts of high-penetration PV integration, presented in this section were completed under the auspices of this project, which is also known at the "NREL/SCE High-Penetration PV Integration Project" [145]. Three other high-penetration PV case studies in the United States are provided in a condensed format in [146].

Fontana, CA High-Penetration Case Study:

In 2009 SCE began the Solar Photovoltaic Program (SPVP), with the goal of installing 500 MW of primarily rooftop PV in their service territory by 2015. This program focused on distribution-connected utility-scale (approximately 1–5 MW) PV systems that would be either utility-owned generation or built and operated by independent power producers. The first PV system installed as part of the program was a 2 MW PV system located on a warehouse rooftop near the city of Fontana, California. The distribution circuit with which the 2-MW PV system is interconnected is shown in Figure 72. This circuit was chosen as one of three study circuits to be studied under the NREL/SCE High-Penetration PV Integration Project.

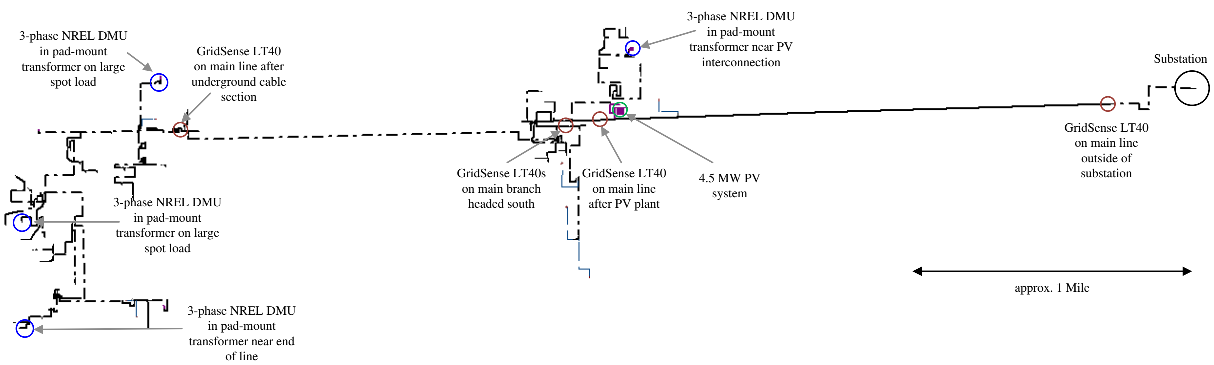

Figure 72: Circuit diagram of the NREL/SCE High-Penetration PV Integration Project's Fontana, California, study circuit

As SCE's SPVP project progressed, an additional 2.5 MW (for a total of 4.5 MW) of PV were installed on the Fontana, CA study circuit in two stages. First, the original 2-MW system was expanded to 3 MW and later an additional 1.5-MW system was added with a POI very near the original PV installation. The circuit was instrumented using both commercially available GridSense LT40 MV line current monitors and an NREL developed distribution-level voltage phasor measurement unit (PMU) called a distribution monitoring unit (DMU) [147]. Instruments were placed on the circuit to measure the impacts of high-penetration PV integration developed by the eventual 4.5 MW of installed PV.

The 4.5 MW PV plant is connected to the local 12 kV distribution system about two miles from the local substation. The entire length of the interconnected distribution circuit is 7.8 miles including all mainline and branch circuits. The distribution circuit serves primarily commercial customers, as most of the area served by the circuit is a warehouse district. Near the end of the distribution circuit other types of commercial loads, such as retail shops in a mall, are served.

Voltage regulation of the circuit is accomplished by switched capacitor banks placed along the length of the mainline of the distribution circuit. The capacitors are controlled using a time schedule with a voltage override. The voltage override operating set points are adjusted automatically if the ambient temperature, measured at the capacitor bank controller, is above 90° F. Voltage regulation at the substation is also accomplished using switched capacitors located at the substation. The capacitors at the substation are operated to both regulate the voltage at the substation bus bars and compensate Var flows in the subtransmission system.

The circuit consists of an express overhead run of 653 ACSR (336 ACSR on the neutral) conductors running just past the PV system installation. Then the circuit continues to additional loads via primarily underground cabling. The mainline cabling is mostly 1000 mil JCN but tapers to 750 CLP near the end of the mainline circuit. Overall, the PV system being nearly the first interconnection to the distribution circuit after it leaves the substation, along with the large conductor size, means that the PV system is connected to a relatively stiff (from a voltage standpoint) interconnection.

The peak load on the interconnected distribution circuit is approximately 4.2 MW, resulting in a PV penetration of potentially 107%. As the load profile is dominated by commercial loads, specifically warehouses, the circuit loading on days when the warehouses are not operating, such as holidays and weekends, the circuit peak load for the day can be much lower. The peak loading for an off-peak day is estimated to be 2.6 MW. Reverse power flow along the distribution line to the substation is common during clear days particularly since the PV system was increased by 2.5 MW.

As part of the analysis completed on the Fontana, California, study circuit an investigation into the possible mitigation of the voltage related impacts of the existing high-penetration PV integration was undertaken. Specifically, the use of advanced inverter capabilities such as off-unity power factor operation, constant Var operation and other POI voltage-responsive Var output capabilities were modeled and analyzed. Figure 73 shows the result of one such investigation looking at the relationship between potential off-unity power factor operation, the effect of partial generation variation on a minute-to-minute timescale due to weather conditions, and the resulting voltage difference seen at the POI of the operating PV system (in this case the larger 3 MW PV system). As shown in the surface plot the voltage variation seen at the PV system POI due to the variations in PV system power output over short time periods can be partially mitigated by the implementation of a constant off-unity power factor operating set point for the operating PV system. Limiting these circuit-level voltage variations is important for two reasons. The first is that voltage variations at the PV system POI will be seen at other customer service POIs along the entire circuit, particularly customers located on the distribution circuit after the PV system POI. Secondly, the voltage along the length of the Fontana, California, study circuit is regulated solely by switched capacitors attached to the MV distribution circuit, and the voltage variations caused by the interconnected PV system could potentially disrupt the expected operation of these devices whose control depends partially on the circuit voltage seen at their locations on the distribution circuit. Further, both of the reasons listed above are commonly the limiting factor regarding the amount of variable generation, such as PV, that can be accommodated on a distribution circuit without the need for potentially expensive distribution circuit upgrades. By limiting the amount of voltage variation caused by the interconnected PV systems, it is very likely that more PV systems could be accommodated before another PV impact limit is reached.

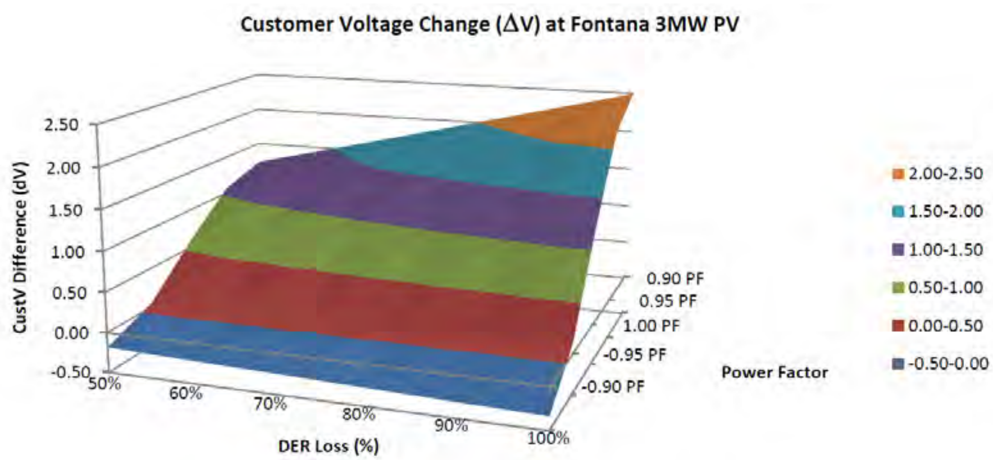

Figure 73: Surface graph of POI voltage change for a range of operating power factor set points and for a range of power production loss metrics

As Figure 73 shows, the optimal mitigation strategy (based on a constant power factor set point in this case) requires the determination of the likely maximum minute-over-minute power production loss or gain that is expected from the given operating PV system characteristics. Table 48 shows the results of analysis completed to determine the number of instances during the year 2011 that the operating PV systems would experience at minute-over-minute loss or gain of power production of 33%, 50%, or 75%. This analysis was completed using data derived from weather satellite data and was processed using cloud motion vector analysis (CPR). The result is that for the aggregated systems on the Fontana, CA study feeder, that are located in close proximity, there are no instances when the short-term variation is greater than 75%. At the variation level of 50% the number of occurrences is on the order of two or three dozen. Instances when the PV plant output changes by 33% are quite common. Using this data it was then possible to plan for the relatively rare occurrence of a 50% minute-over-minute power production loss or gain and use the resulting modeled POI voltage change to select an appropriate PV system power factor operating set point.

Table 48: PV Power Output Variation Expected for Modeled Year 2011

PV Output - Minute over Minute Variation		
Change in Output	Loss of output (instances)	Gain in output (instances)
> 1/3 of Rated Output	51	75
> 1/2 of Rated Output	17	15
>3/4 of Rated Output	0	0

It is important to consider the amount of voltage variation being introduced by the integration of PV systems on a distribution circuit in relation to distribution circuit voltage variations caused by ordinary loads also interconnected. There are many potential ways to estimate the reasonable amount of voltage variation that could be tolerated for a given PV interconnection. They include: limiting the voltage variation to one half of the nearest automatic voltage regulation equipment's voltage control deadband, limiting voltage variation based on voltage flicker concerns, and limiting the voltage variation to typical constraints also applied to new customer interconnections. For this study, a combination of these voltage variation limitations were taken into account, and a conservative level of 0.7 V on a 120 V base was selected to both significantly limit the voltage variation impact of the PV systems and to allow for the potential further integration of PV on the distribution circuit. Table 49 shows the modeled voltage variation results for a range of power factor set points and for expected PV system variation (% loss). From this table a recommended power factor set point to 0.95 inductive (absorbing) Vars was selected as this set point, which greatly reduces the PV systems voltage impact on the distribution circuit over a wide range of potential PV power down ramps. It should be noted that 100% loss of a PV system is possible due to the PV system shutting down due to an internal operational issue or even the PV interconnection breakers tripping during periods of high output due to improper breaker settings. Because these issues impact PV power production, it was assumed by this study that such issues would be resolved quickly and would not become regularly occurring events.

Table 49: Magnitude of PV Systems Point of Interconnection Voltage Change Related to Operating Power Factor Set Point and Expected Production Power Loss (Red Numbers Indicate Voltage Variation Higher than 0.7 volts on a 120-V base.)

		Power Factor				
		-0.90 PF	-0.95 PF	1.00 PF	0.95 PF	0.90 PF
Final DER Loss	50%	-0.18	0.05	0.59	1.06	1.23
	60%	-0.22	0.07	0.72	1.28	1.48
	70%	-0.25	0.08	0.84	1.50	1.73
	80%	-0.28	0.10	0.96	1.72	1.99
	90%	-0.31	0.12	1.09	1.94	2.24
	100%	-0.33	0.14	1.22	2.16	2.50

The NREL/SCE High-Penetration PV Integration Project plans on operating the existing PV systems on the Fontana, California, study circuit using the study recommended PV inverter power factor set point. Aforementioned installed data acquisition systems on the circuit will measure the realized effectiveness of using a constant power factor operating set point to mitigate the voltage-based impacts of high-penetration PV integration. Extensive laboratory testing of the ability of commercially available PV inverters to realize the desired advanced capabilities and the verification of the effectiveness of the identified mitigation strategies has been investigated, and the testing methods and findings are presented in [148] and [149].

Model-Based Assessment of High-Penetration PV Impacts:

In addition to the modeling and simulation completed on the three NREL/SCE study feeders (including the one summarized above), the project has completed a considerable amount of modeling and simulation on IEEE test feeders [150] to determine the expected impacts of high-penetration PV integration on distribution circuits that differ from distribution circuits in SCE's service territory. Studying these circuits was crucial to developing an understanding and a way of quantifying the various distribution circuit impacts seen on circuits that use load tap changing transformers and/or voltage regulators for voltage regulation along the length of the distribution circuit. The model-based assessment summarized below specifically investigated the increased voltage regulator operation due to the voltage variability on the distribution circuit introduced by high penetrations of interconnected PV [151]. Other work completed by the project includes determining the temporal limits of quasi-static time-series simulation by comparing transient level simulation results with quasi-static time-series simulation results completed at various simulation time steps [152].

Figure 74 shows the topology of the IEEE 34 node test feeder that was used for this model-based case study. Although this circuit is presented as a generic test model, the basis for this circuit is an actual distribution circuit in the Desert Southwest of the United States. The circuit is a 24 kV system with a total main circuit length of nearly 36 miles. The circuit uses two voltage regulators to regulate the voltage profile along the length of the circuit. The data needed to perform a yearlong quasi-static time-series simulation with a 1 minute time step was developed and is detailed in [151]. Once time-varying load data, modeled PV plant output data, and the time-dependent models of the circuit's voltage regulators were developed, a number of analyses were completed to gain insight into how the impacts of high-penetration PV integration impacted the distribution circuit.

The impact that high-penetration PV integration has on the POI voltage is shown in Figure 75. These color graphs show the per unit voltage (on the MV side) for every minute of the model year 2010. The voltages shown are for node 840, which is representative of a requested PV interconnection near the end of a rural distribution circuit. The base case, circuit operation with no interconnected PV, is presented as well as the voltages seen when a 2-MW system (assumed to be a fixed rooftop-mounted system with no tilt) is interconnected. Both the diurnal and seasonal impacts of the PV system interconnection can be seen. At 2 MW, the voltages present at any given time do not necessarily exceed the circuit's operational limits, but the change in the circuit's operational characteristics (i.e., voltage level) is apparent.

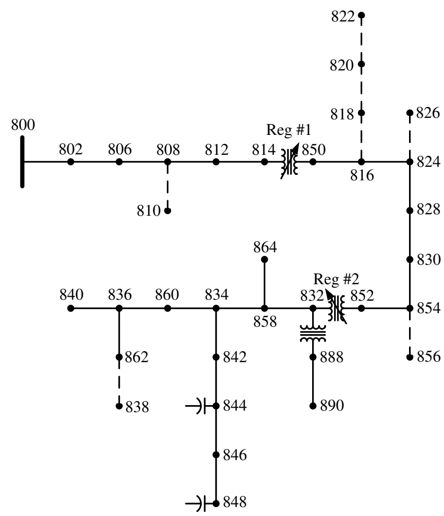

Figure 74: Single-line diagram of the IEEE 34 node test feeder showing the location of the two voltage regulators and two fixed-shunt capacitors

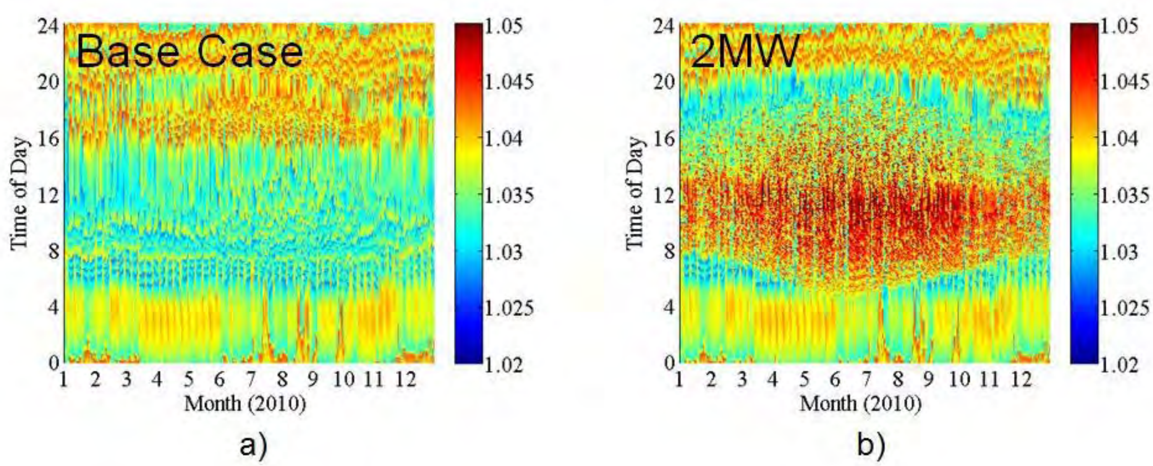

Figure 75: Color graphs of the POI voltage (node 840) for every minute of the year in 2010 with a) no PV interconnected and b) a 2-MW PV system connected at node 840

Figure 76 shows the results of a further investigation into the modeled operation of the two voltage regulators for the case of a 1 MW system interconnected at node 840 (end of the mainline). The modeled power output of the PV plant is shown time-aligned with the tap positions of the two voltage regulators. As shown, there is a direct correlation to voltage regulator operation (tapping up or down) and variability in the PV systems power output. This is clearly shown in the graphs that show the same data for a time period between 10 a.m. and 1 p.m. Additional quasi-static time-series simulations were completed to determine the locational sensitivity of the PV interconnection location on the impact of the two voltage regulators. The results of that analysis are presented in Figure 77. This figure shows the percentage increase modeled for both voltage regulators when a 1 MW PV system is interconnected at any node along the length of the mainline distribution circuit. This type of analysis provides considerable insight to distribution engineers tasked with evaluating the impact of requested PV interconnections on their distribution system. As shown, the impact on voltage regulator operation is minimal if the PV system is interconnected within about 7 miles of the substation. Voltage regulator #2 is not heavily impacted unless the PV is interconnected past voltage regulator #2 (about 20 miles from the substation in this case).

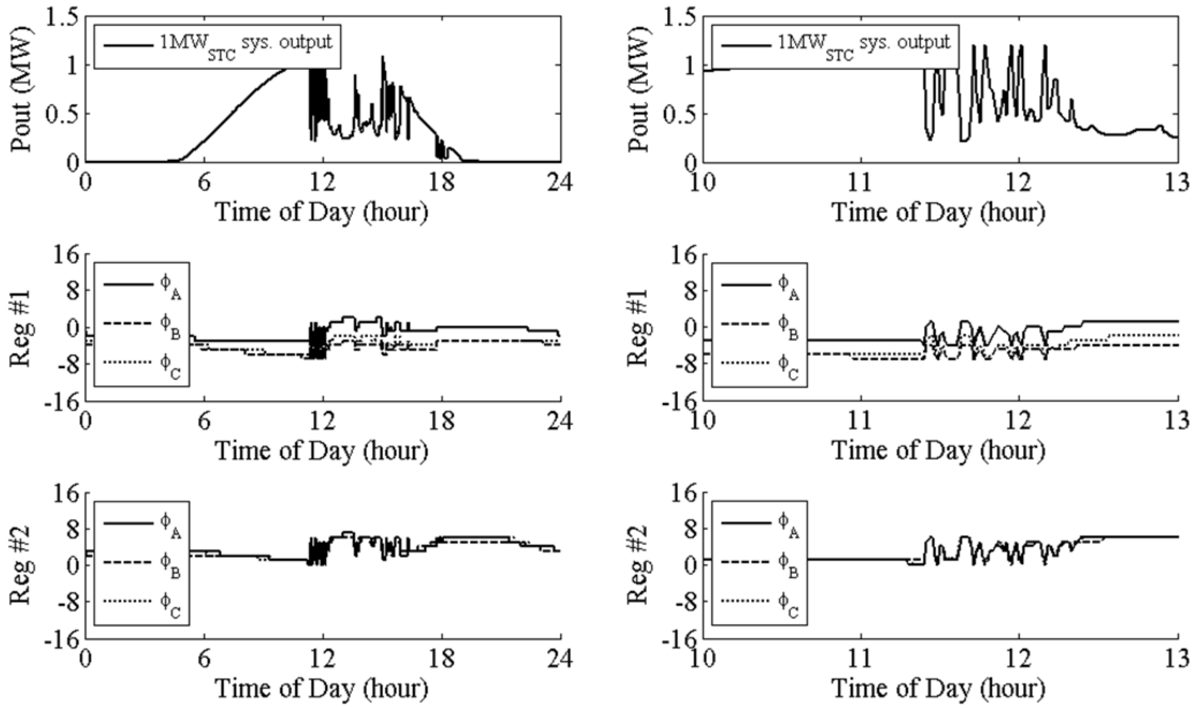

Figure 76: Model results of voltage regulator operation during periods of highly variable generation on June 16, 2010. The graphs on the right show regulator operation during the entire day. The graphs on the left show operation from 10 a.m. to 1 p.m.

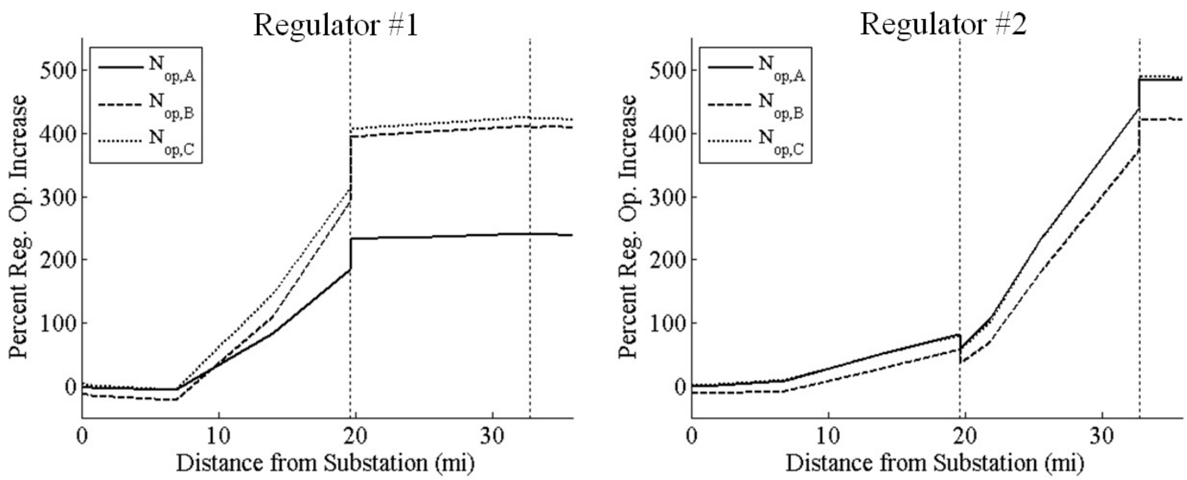

Figure 77: The modeled voltage regulator operation impact of interconnecting 1 MW of PV at any point along the distribution circuit

Upcoming Regulatory Changes and Future Challenges for High PV Penetration

As penetration levels of PV integrated into the U.S. distribution grid increase, a number of already present challenges will garner more attention and will need to be addressed more aggressively. Three future challenges to the increased penetration of PV are discussed below. While this is not an exhaustive list of future challenges, it presents some of the larger known challenges.

Standards:

As mentioned above recent amendments have been undertaken to the primary technical standard relating to PV interconnection, namely IEEE 1547 [140]. In addition to an amendment, a complete revision of the entire standard is likely in the near future. Many of the discussions about proposed changes to the standard include the possible requirement of PV inverter operation during abnormal frequency and voltage events. Additionally, many advanced inverters (sometimes referred to as smart inverters) are being proposed and may be required for some PV interconnections. For standards to appropriately address many of these issues, a great deal of research focused on determining the electric power system impacts of high-penetration PV is needed. For instance, there are still major questions regarding what minimum frequency and voltage ride-though characteristics should be required on distribution-connected PV systems to no adversely impact the overall reliability of the larger subtransmission and transmission systems. Further, very little research has been completed that shows how PV inverters implementing some advanced capabilities interact with other PV inverters and other distribution system equipment. Rule 21 in California [153], the tariff that describes the regulated process of DG interconnection, is also currently being revised, and developments in revisions would benefit from similar technical inputs as mentioned above in regards to IEEE 1547.

Regulatory Policy/Business Models:

Net metering, when on-site generation directly offsets on-site load in terms of energy cost and not necessarily power usage, has been relatively widely implemented in the United States for small, typically residential, PV systems. Additionally, other tariffs and regulated interconnection agreements have been developed that are also not revenue neutral in respect to the cost of the utility to serve the customer load versus the loss in energy and demand charges. As more and more of these systems have been installed, a growing concern by utilities has arisen regarding the future prospects of maintaining a viable business under their current business model. To maintain the overarching benefit that electric utilities have been providing for more than a decade, it is now being discussed that alternative business models and cost recovery structures will need to be implemented. To provide as smooth as possible transition to these new business models, the impacts of these proposed business models on present and future PV integration should be studied.

Increasing the Efficiency of PV Integration:

While the technical challenges of integrating high penetrations of PV onto the electric power system are now better understood and quantified for a number of cases, challenges remain to make the technical process of PV integration more efficient. For instance, the effectiveness and accuracy of PV interconnection request screens (i.e., the "fast track screens" shown in Figure 71) are being investigated in a new research effort funded by the CPUC and DOE [144]. The goal is to develop advanced PV interconnection screens that accurately identify PV interconnection requests that do not need to be studied further. Additionally, the information required to implement the screens are based on easily attainable, general data, as to not necessitate considerable effort just to check the developed interconnection screen.

Another valuable approach is to develop fast and more automated ways to determine the impact of any given PV interconnection request. A number of commercial and government funded projects currently have this goal.

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Appendix

Table 50: Applied Local Control Strategies in German Case Study [84]

Category	Scenario	Applied Parameterization
Grid Reinforcement	No Voltage Control	No active voltage control of MV/LV transformer and PV Inverters
On-load tap changer of MV/LV transformer	OLTC with Vset=1.0 p.u.	V_{Set}= 1.0 p.u. at MV/LV-transformer (LV-Side) Deadband = V_{Set} ± 0.02 p.u.
	OLTC with Vset=0.98 p.u.	V_{Set}= 0.98 p.u. at MV/LV-transformer (LV-Side) Deadband = V_{Set} ± 0.02 p.u.
Autonomous Inverter Control Strategies	CosPhi(P)	According to VDE AR 4105
	Q(V) with PF limitation	V_1 = 1.05 p.u., V_2 = 1.08 p.u., $\cos\phi_{min}$=0.95
	Q(V) without PF limitation	V_1 = 1.05 p.u., V_2 = 1.08 p.u.
	Q(V) / P_{max} 70% limitation	V_1 = 1.05 p.u., V_2 = 1.08 p.u., P_{max}=70% P_{STC}
	Q(V) / P(U)	V_1 = 1.05, V_2 = 1.08, V_3 = 1.08, V_4 = 1.09, P_{min}=70% P_{STC}

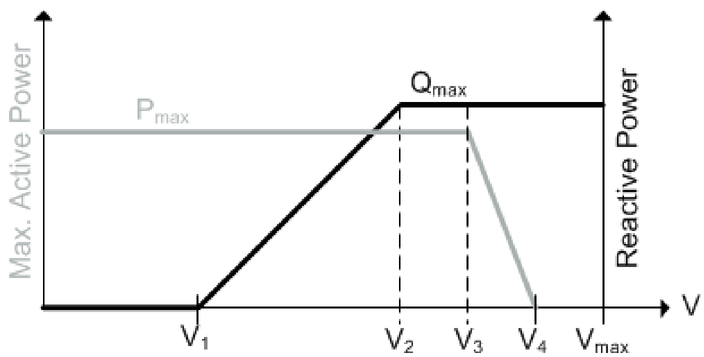

Figure 78: Applied Q(V)/P(V) characteristic in the German case study [84]

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