Technology Collaboration Programme
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International Energy Agency
Photovoltaic Power Systems Programme

Task 14 Solar PV in the 100% RES Power System

PVPS

Reactive Power Management with Distributed Energy Resources
2024

Report IEA-PVPS T14-16:2024

What is IEA PVPS TCP?

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

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

The 25 IEA PVPS participating countries are Australia, Austria, Belgium, Canada, China, Denmark, Finland, France, Germany, Israel, Italy, Japan, Korea, Malaysia, Morocco, the Netherlands, Norway, Portugal, South Africa, Spain, Sweden, Switzerland, Thailand, Turkey, and the United States of America. The European Commission, Solar Power Europe, the Smart Electric Power Alliance, the Solar Energy Industries Association, the Solar Energy Research Institute of Singapore and Enercity SA are also members.

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What is IEA PVPS Task 14?

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

ISBN

978-3-907281-51-2

COVER PICTURE

Fraunhofer IEE

TITLE

Reactive Power Management with Distributed Energy Resources

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INTERNATIONAL ENERGY AGENCY

PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

IEA PVPS Task 14

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Report IEA-PVPS T14-16:2024
March 2024

ISBN 978-3-907281-51-2

TABLE OF CONTENTS

ACKNOWLEGMENT

This report received valuable contributions from several IEA-PVPS Task 14 members and other international experts. Many thanks to:

Federal Ministry for Economic Affairs and Climate Action

The Fraunhofer IEE and the Technische Hochschule Ulm contribution are supported by the German Federal Ministry for Economic Affairs and Climate Action and the "Projektträger Jülich GmbH (PTJ)" within the framework of the project "PVin100RESPS" (FKZ: 03EE1009A/B). The authors are solely responsible for the content of this publication.

Schweizerische Eidgenossenschaft
Confédération suisse
Confederazione Svizzera
Confederaziun svizra

Swiss Federal Office of Energy SFOE

The Bern University of Applied Sciences is supported by the Swiss Federal Office of Energy (OFEN)

MINISTERO DELL'AMBIENTE
E DELLA SICUREZZA ENERGETICA

ENEA contribution was funded by the research fund for the Italian electrical through the project "Accordo di Programma 2022–2024 – Project 2.3" between ENEA and the Ministry of the Environment and Energetic Safety (MASE).

Federal Ministry
Republic of Austria
Climate Action, Environment, Energy, Mobility, Innovation and Technology

The Austrian contribution is supported by the Federal Ministry for Climate Action, Environment, Energy, Mobility, Innovation and Technology, by the FFG and by the IEA Forschungskooperation.

FFG
Promoting Innovation.

IEA Forschungskooperation
im Rahmen von open4innovation

METI
Agency for Natural Resources and Energy

NEDO Projects are supported by the Agency for Natural Resources and Energy, Ministry of Economy, Trade and Industry of Japan. The authors are solely responsible for the content of this publication.

LIST OF ABBREVIATIONS

ADAF	Advanced day-ahead forecast
CharDF	Characteristic day profile
CHP	Combined heat and power plants
DCC	Demand and Connection Code
DER	Distributed energy resources
DG	Distributed generation
DMS	Distribution management system
DSO	Distribution System Operator
E.DSO	European Distribution System Operators
EHV	Extra High Voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
HV	High Voltage
ICT	Information and communication technologies
IEA	International Energy Agency
JPAEA	Japan photovoltaic energy association
LDC	Line drop compensation
LV	Low Voltage
MAE	Mean Absolute Error
MV	Medium Voltage
NCP	Network Connection Point
NMRP	Non-discriminatory and market-based reactive power procurement
NWP	Numerical weather prediction
OLTC	On-load tap changer
P.F.	Power factor
PCC	Point of Common Coupling
PCS	Power Conditioning System
PV	Photovoltaics
PVPS	Photovoltaic Power Systems Programme
rCC	Reactive capacity credit
RES	Renewable energy sources
RFH	Reactive flexibility hour
SDAF	Standard day-ahead forecast
SIDF	Standard intraday forecast
STATCOMs	Shunt-connected static synchronous compensators
TSO	Transmission System Operator

LIST OF FIGURES

EXECUTIVE SUMMARY

The increased integration of variable renewable energy sources into the power grid can, amongst others, lead to fluctuations in voltage, which may result in issues like harmonics, flicker, unbalanced loads, and power oscillations. These factors can negatively impact power quality and the ability to transfer power effectively. Therefore, effectively managing reactive power becomes crucial for stabilizing the grid, facilitating voltage control, and ensuring high power quality. In addition, distributed energy resource (DER) systems need to take over more responsibility by providing reactive power control. This improvement in power system stability plays a key role in preventing problems like load shedding and system collapse, ultimately enhancing the overall security and reliability of the power system.

Effective reactive power management of DERs becomes indeed a crucial aspect of grid operation essentially for voltage maintenance and for ensuring the stability of the grid.

There are different solutions available for managing reactive power, each tailored to specific needs. For example, fixed power factor or reactive power setpoint for PV plants, voltage-dependent reactive power provision ($Q(V)$), or static synchronous compensator (STATCOM) functionalities provided by DER. Unlike active power management [1], reactive management and voltage control is a rather local issue, so that they need to be tailored to the local environment and may also have adverse effects if implemented uncoordinated.

Contrastingly, due to the substantial number of involved plants, especially when also including, e.g., residential PV plants, harmonization and standardization is a must to enable grid operators efficiently include respective control functionalities and lever the possibilities this flexibility brings. For larger systems, oftentimes an inclusion in centralized (optimized) system controls may be beneficent.

Standardization of decentralized solutions for effective reactive power management are crucial for system-wide usage and application. Reactive power regulations therefore play a fundamental role in shaping power system operations amid rising renewable energy integration.

This report highlights the status and the potential of reactive power management in the presence of high renewable energy sources shares. The focus is to give an overview of reactive power regulations across several IEA PVPS Task 14 countries, including grid codes and frameworks that shape the requirements for connected distributed energy resources to provide reactive power control.

In addition, the report exemplarily examines how these regulations influence the operation of power systems with increasing integration of renewable energy sources. The report therefore discusses reactive power control support potential using DER based reactive power capabilities through different research case studies.

- **Reactive power support potential by DERs:** The study focuses on the development and discussion of transparent performance indicators for the availability of DER reactive power support. Key performance indicators are introduced and defined. The results illustrate that Hydro and Thermal DER with fixed reactive power capability, as well as all DER types with STATCOM capability, can have significant contributions in terms of these performance indicators.

- **Forecasts for the reactive power flexibility potential of PV plants:** The main objective in this study is to forecast reactive power flexibility potential for MV PV plants. An evaluation of various PV forecasting approaches is obtained using different reactive power capabilities . A reliability indicator is introduced to evaluate the accuracy of reactive power flexibility forecasts in comparison to actual observations, emphasizing the importance of preventing overestimation. Furthermore, the study explores the use of a reactive power planning reserve to enhance the reliability of reactive power flexibility forecasts. It discusses the trade-off between improved reliability and the reduction of forecasted reactive power flexibility potential. While certain methods demonstrate improvements in forecasted power values, careful consideration is needed to avoid overestimating exceptionally low power values, especially in specific use cases. High reliability forecast requirements will be necessary for using DER reactive power support as an ancillary service.

DERs contribute significantly to grid stability by leveraging their reactive power capabilities. Forecasting flexibility will be necessary, emphasizing the need for a delicate balance between improving forecasts and preventing overestimation to ensure DER reactive power support.

Furthermore, research examples, including use cases from three different IEA PVPS Task 14 countries, are highlighting these reactive power management applications using photovoltaics and other renewables:

- **Application-oriented reactive power management (Germany):** The application-oriented reactive power management approach is motivated by the need of Distribution System Operators (DSOs) to control reactive power exchange at grid interfaces, supporting local voltage stability without complex infrastructure. The method focuses on controlling reactive power exchange at the 110 kV network connection point using local reactive power from DERs at the MV level. The control process involves determining target values, assessing deviations, setting reactive power set-points for controllable MV-DERs, and implementing local limitations based on extended Q(V) characteristics. In addition, the implemented solution demonstrates adaptability to different control scenarios, highlighting its flexibility in response to varying grid conditions.
- **Methods and Scenarios for Strategic Grid Planning in Distribution Networks (Austria):** The study conducted in Austrian low voltage grids aimed at a quantitative survey of the area effectiveness of future network-related measures. Aligned with European requirements, Austria mandates certain reactive power management functionalities for power electronic-based grid interfaces, such as PV inverters. However, current practices reveal limited utilization of these capabilities, with a predominant focus on $\cos \varphi = 1$ during residential PV integration. The study considered various scenarios, including the impact of climate policy goals, regionalized technology rollouts, and different operating strategies related to PV, heat pumps, and e-mobility. Identified challenges include the need for a differentiated and detailed analysis of Q(V) control contributions within DSO supply areas. Discussions around reducing reactive energy demand explored options such as PV curtailments and primary substation current compounding. The study indicates a growing consideration of Q(V) as a future option among Austrian DSOs. However, a lack of capability for large-scale grid simulations emerged as barrier, hindering a comprehensive understanding of the value of reactive power management in distribution grids.
- **Evaluation of the voltage control performance in distribution system (Japan):** In response to the growing challenge of maintaining proper voltage levels in distribution systems amid increasing PV penetration, a comprehensive project was conducted by a consortium involving TEPCO Power Grid, Tokyo Electric Power Company Holdings, Inc., and Waseda University. Supported by the New Energy and Industrial Technology Development Organization (NEDO), the project aimed to evaluate the voltage control performance under various scenarios, considering PV penetration from 2025 to 2040. While the current voltage control is conducted by fixed power factor control with different fixed values for each voltage class, the study suggested it may be difficult to maintain an appropriate voltage due to the increase in the amount of PV interconnection in the distribution system. Based on these findings, although it continues to adopt a fixed power factor control strategy, "the power factor setting value must be changed according to the request of DSOs, with a function that allows it to be changed" was stipulated in the new grid code published in 2023.

Reactive power management is an essential aspect in achieving optimal grid performance. Various new methodologies are needed and being developed considering difference scenarios and highlighting the necessity for adaptability in response to evolving energy landscapes.

In summary, advancing reactive power management is crucial in the evolving energy landscape. Research, especially in forecasting and control algorithms, is essential for efficient power systems. Regulatory frameworks need prompt updates, necessitating strengthened collaboration between TSOs and DSOs. Exploring DER potential and leveraging information and communication technologies (ICT) for enhanced coordination are key components to ensure resilience and efficiency in power systems.

1 INTRODUCTION

1.1 Power system transformation

Under the Stated Policies Scenario [2] the world's electricity generation capacity is projected to grow by 80% by 2040, reaching over 13,000 GW from 7,220 GW in 2018. Renewable energy sources are expected to play an increasingly dominant role, with their share of global power capacity rising from 35% today to 55% in 2040. Solar photovoltaic (PV) is set to become the leading source of power capacity around 2035, surpassing wind power in 2020, hydropower in 2027, coal in 2033, and natural gas in 2035 (see Figure 1) [3].

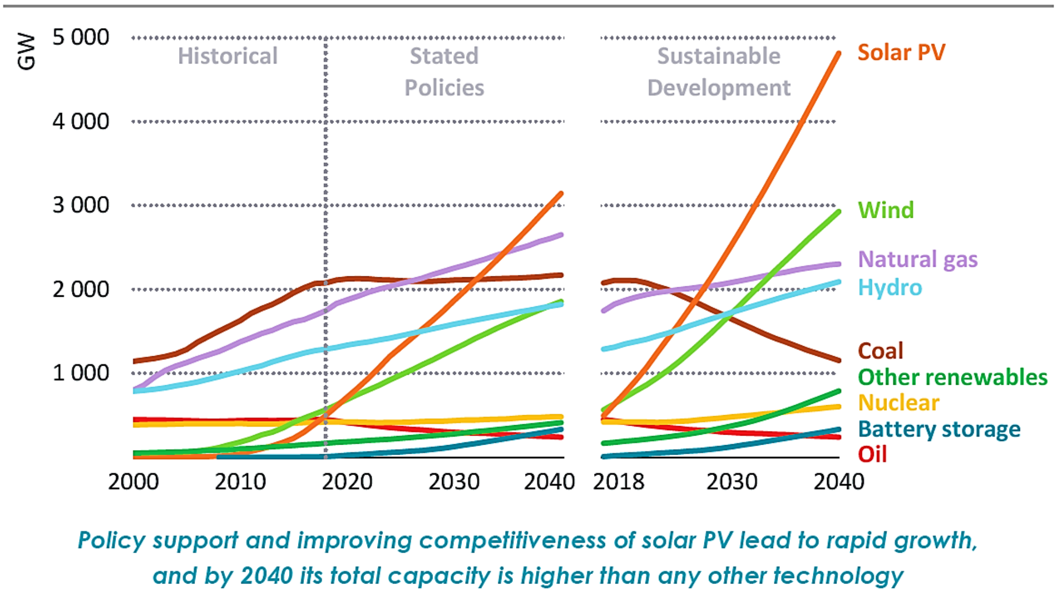


Figure 1: Global power generation capacity by source and scenario [3].

Wind power is also anticipated to experience steady growth, reaching over 1,850 GW of capacity by 2040, putting it on par with hydropower. Offshore wind is expected to play an increasingly key role in this growth. Thus, the penetration of variable and intermittent DER, especially medium voltage (MV) PV plants and low voltage (LV) residential PV are increasing at the distribution level. As a result, challenges in the distribution system operation can arise more frequently, such as congestion of grid assets and voltage violations. These challenges force distribution system operators (DSO) to operate under increased uncertainty.

1.2 Goals of this Report

The European power system change is mostly driven by three main trends called "The three Ds", namely Decarbonization, Decentralization, and Digitalization [4]. Several relevant studies reveal that the trend towards more actively managed distribution systems is set to continue [4]. In active distribution grids, the DSO can request assistance from the DER to make the grid operation more efficient and handle the increased uncertainty. Furthermore, active distribution networks can provide services and active and reactive power flexibility to the TSO.

REPORT GOAL: What is the essential role of reactive power in the power system, and how can suitable reactive power control significantly support secure and reliable grid operation?

The distribution grid has undergone significant changes, particularly with the increasing utilization of distributed energy resources, primarily derived from renewable energy sources. Effectively managing a grid that heavily relies on renewable energy sources necessitates the revision of existing practices and the development of innovative approaches to address the fluctuating nature of these resources. These novel approaches may require a more proactive stance from the DSO, such as engaging in contracts or exerting control over the flexibility of distributed energy resources to mitigate congestion and voltage-related challenges.

Therefore, to guarantee a reliable provision of electrical energy and enhance the hosting capacity of the grid, it is essential to expand and strengthen the distribution grid. Various local voltage control methods, such as Fixed cos φ, cos φ (P), and Q(V), are outlined in various electrical grid guidelines. Applying local voltage control approaches, together with the grid reinforcement and higher degrees of cabling in the future, may lead to changes of reactive power behaviors in distribution systems. However, the reactive power Q is essential in the power system since it is necessary for the operation of the entire power system. Using suitable and appropriate reactive power control could significantly support, e.g., the voltage regulation, supply quality, suppression of voltage dips, stable operation of (classical) direct current links in todays and tomorrows power system operation. For further reference, e.g., see [5–7] and the references mentioned therein.

REPORT GOAL: How can optimizing reactive power flow within the power system empower DSOs to offer various ancillary services, including enhancing reactive power behavior, resolving overloading concerns, assisting in voltage limitation, minimizing overall grid losses, and facilitating reactive power balancing at interfaces between transmission and distribution grids?

Moreover, effective optimization of reactive power flow within the power system empowers the DSO to offer various ancillary services [8], including:

- Enhancing the reactive power behavior in the distribution system through local reactive power compensation.
- Resolving overloading concerns related to lines and transformers.
- Assisting in voltage limitation at higher voltage levels by supplying the requested reactive power exchange at network connection points.
- Minimizing overall grid losses, encompassing internal park losses and network losses.
- Facilitating reactive power balancing at the interfaces between transmission and distribution grids.

REPORT GOAL: What is the current status and potential of reactive power management in the presence of high renewable energy sources shares across different IEA PVPS Task 14 countries, and how do reactive power regulations influence power system operation with increasing integration of renewable energy sources?

1.3 Target Audience

This report aims to highlight the status and the potential of reactive power management in the presence of high renewable energy sources shares. The report provides an overview of reactive power regulations across several IEA PVPS Task 14 countries, including grid codes and frameworks that shape the requirements for connected distributed energy resources to provide reactive power control. In addition, examines how these regulations influence the operation of power systems with increasing integration of renewable energy sources. Furthermore, research examples, including use cases from three countries are to be featured highlighting these reactive power management applications using photovoltaics and other renewables.

The information and findings are targeted to technical experts from the utility sector, project developers as well as technical consultants, seeking for technical solutions and experiences on the implementation and usage of reactive power control. In addition, the contents of the report also are relevant for the work of standardization and professional organizations and regulatory authorities.

2 REGULATORY FRAMEWORK IN SELECTED COUNTRIES

To maintain a stable power system, all generators and DER connected to the power system must adhere to certain grid codes. Grid codes are set to secure a stable power system. These codes specify the requirements for DER regarding different power quality issues such as reactive power control.

In this chapter, the regulatory development, and the grid requirements for DER regarding reactive power capability in selected countries are discussed. In Figure 2, a comprehensive summary of reactive power regulations across the five presented IEA PVPS Task 14 countries is shown.

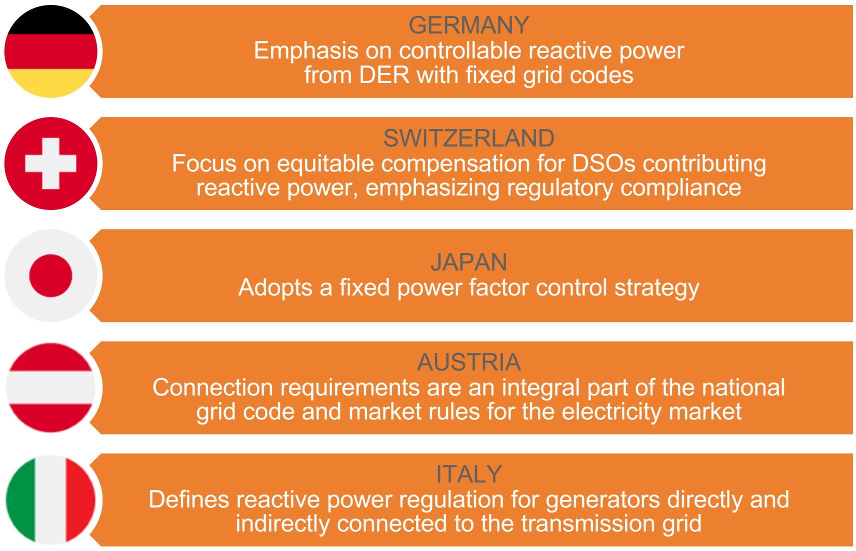


Figure 2: Overview of regulatory frameworks in five Task 14 countries.

2.1 Germany

2.1.1 Grid code (VDE-AR-N)

In Germany, current grid codes require that connected DER must be capable of providing controllable reactive power at their feed-in times. Therefore, DSO have the benefit of using the reactive power provision of DER within the predefined reactive power range in the relevant guidelines for their own objectives to provide several types of additional system services. These grid codes and requirements are given based on the connected voltage level.

2.1.1.1 VDE-AR-N 4105 (LV level)

VDE-AR-N 4105 summarizes the essential aspects to be considered when connecting generating plants to the grid operator's public LV grid [9]. It is to be used for generation plants and energy storage systems that are newly connected to the LV grid, as well as for the expansion or modification of existing plants. This introduces dynamic grid support. This is intended to prevent grid instability or grid disconnection, such as unintentional shutdown as a result of brief voltage dips or voltage increases is prevented.

In Figure 3 an illustration of the minimum technical requirements for the reactive power provision Q of DER, based on the active power feed-in P and the installed capacity S_n of the DER is presented. The values are given in per-unit. The $Q(P)$ diagram with light blue applies to DER with an installed capacity of 4.6 kVA or less, while the diagram with darker blue color applies to DER with an installed capacity greater than 4.6 kVA. In order to support local voltage limitations at the LV level, DER with a small installed capacity ($S_n \leq 4.6$ kVA) should be able to provide reactive power at their feed-in time with a minimum power factor of 0.95, according to Figure 3, for both underexcited and overexcited reactive power provision. Larger DER ($S_n > 4.6$ kVA) should be able to provide reactive power with a minimum power factor of 0.9 for both under- and overexcited conditions.

2.1.1.2 VDE-AR-N 4110 (MV level)

VDE-AR-N 4110 outlines the technical connection rules for the design, construction, operation, and alteration of customer facilities (demand facilities and generation plants, storage facilities, and mixed installations) that are connected to a medium voltage network at the grid connection point [10]. This guideline is also relevant for a situation in which a customer's facility is connected to a private low voltage network, and this private network is connected to the public medium voltage network through transformers and connection lines. It is not applicable when a demand facility or a mixed installation is connected to a private medium voltage network, but the connection of the private medium voltage network to the public network is part of the high voltage network. Instead, the technical connection rules for the high voltage network (VDE-AR-N 4120) are to be followed in such cases.

According to VDE-AR-N 4110, Figure 3 shows the minimum technical requirements for the reactive power provision capability of DER connected at the MV level. These requirements are based on the active power feed-in and the installed DER capacity and are presented as a *Q(P)* diagram in per-unit values. MV level DER must have the ability to provide reactive power with a minimum power factor of 0.95 at the time of feed-in, in order to support local voltage limitations at their point of common coupling and at the MV level as a whole. In comparison to DER at the LV level, MV level generators must be able to provide reactive power within a fixed range as long as their active power feed-in exceeds 20% of their total installed capacity. For DER with low active power feed-in ($-0.1 \leq P/S_n \leq 0$), specific requirements for reactive power provision capability are not given. However, to avoid unwanted reactive power from DER, the reactive power behavior of DER measured at the point of common coupling (PCC) should not exceed a predetermined range from 0.05 underexcited to 0.02 overexcited.

2.1.1.3 VDE-AR-N 4120

VDE-AR-N 4120 [11] the minimum technical requirements for the reactive power provision capability of generators connected at the HV level. Figure 3 presents these requirements as a *Q(P)* diagram, showing the required reactive power provision in relation to the active power feed-in and installed capacity from the perspective of the consumer. The VDE-AR-N 4120 offers three options for reactive power ranges for HV level generators to choose from. These options specify that generators connected to the HV level must meet one of the following requirements for reactive power provision.

- Variant 1: cos φ = 0.9 overexcited to cos φ = 0.975 underexcited (from −0.48 p.u. to 0.23 p.u.)
- Variant 2: cos φ = 0.925 overexcited to cos φ = 0.95 underexcited (from −0.41 p.u. to 0.33 p.u.)
- Variant 3: cos φ = 0.95 overexcited to cos φ = 0.925 underexcited (from −0.33 p.u. to 0.41 p.u.)

Based on the specific circumstances at the PCC of a generator (such as the location and voltages at the PCC), DSO have the option to choose one of the suggested options for the reactive power provision capability of the generator connected at each PCC. In addition, generators connected at the HV, and extra high voltage (EHV) levels

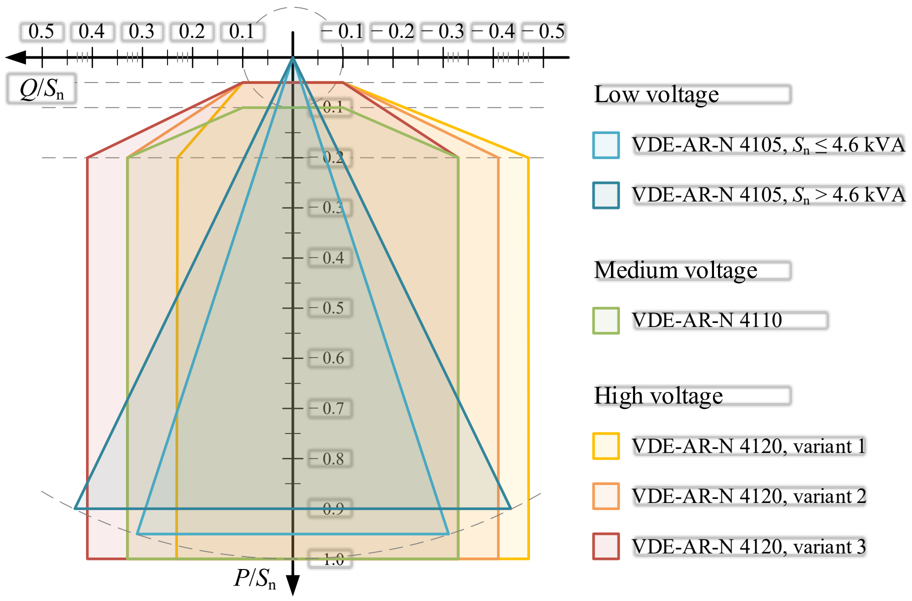


Figure 3: Requirements on reactive power provision capability for DER (based on [9–11])

should also have the ability to provide reactive power within one of the fixed reactive power ranges, as long as their active power feed-in exceeds 20% of their total installed capacity.

2.1.2 Market-based Reactive power procurement

According to § 12h of the German Energy Industry Act [12], the procurement of non-frequency-based system services by system operators has to be transparent, non-discriminatory, and market-based. New schemes draft of reactive power procurement published recently by the German Federal Network Agency in 2023 currently are in consultation. The regulation is based on the following principles:

- Non-discrimination: All market participants must have equal access to the market.
- Market-based pricing: The price of reactive power in the market will be determined by supply and demand.
- Transparency: The market will be transparent so that market participants can make informed decisions about their procurement of reactive power.

The reactive power procurement process in general comes along in a concept of three reactive power procurement sources as given in Figure 4.

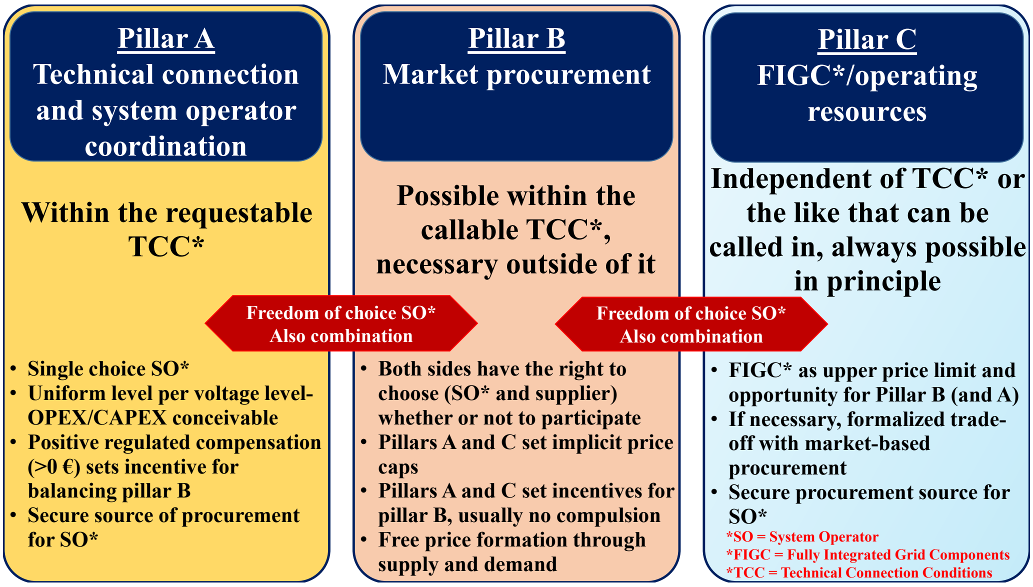


Figure 4: Overview of the three pillars of reactive power procurement (based on [13]).

A market-based procurement is intended to be only required if a corresponding reactive power requirement exists or is forecasted and if market-based reactive power procurement is classified as the most economic option for the respective system operator considering three available procurement options.

Therefore, in the following the term non-discriminatory and market-based reactive power procurement (NMRP) is used. The NMRP aims to improve the efficiency of the German power grid by allowing market participants to procure reactive power levering the following benefits, amongst others:

- Increased efficiency of the German power grid: NMRP will allow market participants to procure reactive power when and where it is needed, which will improve the efficiency of the power grid.
- Lower costs for consumers: NMRP is expected to reduce costs for consumers, as they will not have to pay for reactive power that they do not need.
- Increased competition: NMRP will create new opportunities for competition in the provision of reactive power, which will benefit consumers.

In a first step, NMRP is intended to be introduced to the EHV and HV grids but is expected to also reach out to the lower voltage levels in the future. NMRP itself is based on four standard products that are shown in Figure 5.

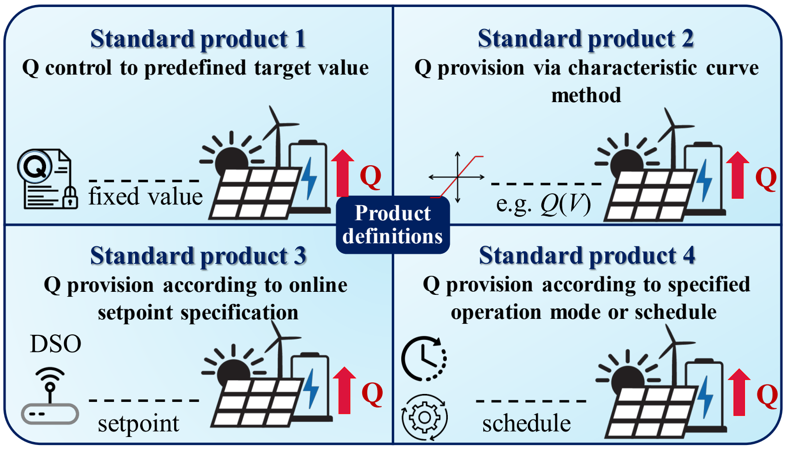


Figure 5: Defined standard products in the NMRP (based on [14]).

The procurement is intended to be conducted independently by the system operators for their own grid from providers connected to their grids, respectively. For this purpose, they may define several procurement regions within their own grid area while not affecting the grid operators' obligations to cooperate.

The system operator may demand secured reactive power (continuously available) and unsecured reactive power (not continuously available) for the products. In the case of secured reactive power, the provision is also compensated. Compensation may only be provided for reactive power or reactive power reserve beyond the technical connection conditions (see previous subsection).

2.2 Switzerland

Switzerland unofficially used to follow the German VDE AR-N 4105 and has now adopted the SN EN 50549 series. In principle, each of the 600 DSOs has its own grid connection requirements. However, most DSOs follow the recommendations of the Association of Swiss DSOs (Verband Schweizerischer Elektrizitätsunternehmen, VSE). The recommended settings are published in the country settings, available at [15]. The settings differentiate between generator Type A (800 W - 250 kW) and Type B (250 kW – 36 MW). However, for reactive power control, the standard settings are cos φ = 1, unless the local DSO requests different settings. Swiss DSOs are gradually beginning to take reactive power control into account in their network planning processes. The combination with active power management has also been discussed since around 2020. However, due to regulatory hurdles (especially feed-in priority for renewable energies), active power management is only used in individual projects if it is to the advantage of the plant operators.

2.3 Japan

In Japan, when connecting DER to power transmission lines, which vary depending on the area, but generally 22 kV or 33 kV or higher, it is required to maintain voltage within about ±1 to 2% of nominal voltage, and when connecting DER to low voltage power distribution lines, it is required to maintain the voltage at the connecting point within 101 ± 6 V for the standard voltage of 100 V and within 202 ± 20 V for the standard voltage of 200 V, according to the Electricity Business Act and the grid interconnection technical requirement guideline related to power quality established by Japanese government. In present condition, the voltage in distribution systems is mainly regulated by tap operation of On-Load Tap Changer (OLTC) and Step Voltage Regulator (SVR) of DSOs. To eliminate localized voltage violations due to DER, reactive power control such as fixed power factor control and volt-var control is applied by power conditioning system (PCS) of each DER.

While maintaining consistency with other agreements, the current Grid-interconnection Code (JEAC9701) requires that connecting DER must be set a minimum value for the power factor (cos φ = 0.85) at the interconnection point, and it is also stipulated that the power factor should not be leading (capacitive) when viewed from the grid, to restrain voltage raising. Because it makes the burden of reactive power injection fair among DER consumers and reduces the impact on the surrounding area, fixed power factor control is specified as effective in distribution systems. For low-voltage interconnecting PV (～ 200 V, for buildings and residentials) in distribution systems, which is expected to expand, the standard power factor is stipulated at 0.95 in the current Grid-interconnection Code. This is subject to change after consultation. The power factor value for medium-voltage interconnecting PV (~ 6.6 kV, which is called “high-voltage” in Japan) is set in discussion with the DSO, while typically it is set at 0.90 lagging. If these measures cannot be taken, grid reinforcement, etc. will be carried out, and the applicant will, in principle, be required to bear the expenses necessary for this grid interconnection.

To keep the voltage constant based on these regulations or set values, PCS of DER such as PV is controlled so that the value of the operating power factor is constant based on the voltage at the interconnection point. Reactive power flows into the grid at a constant rate according to the output. As a concrete example, the typical control flow for restraining voltage rise in low voltage distribution systems is as follows (see Figure 6).

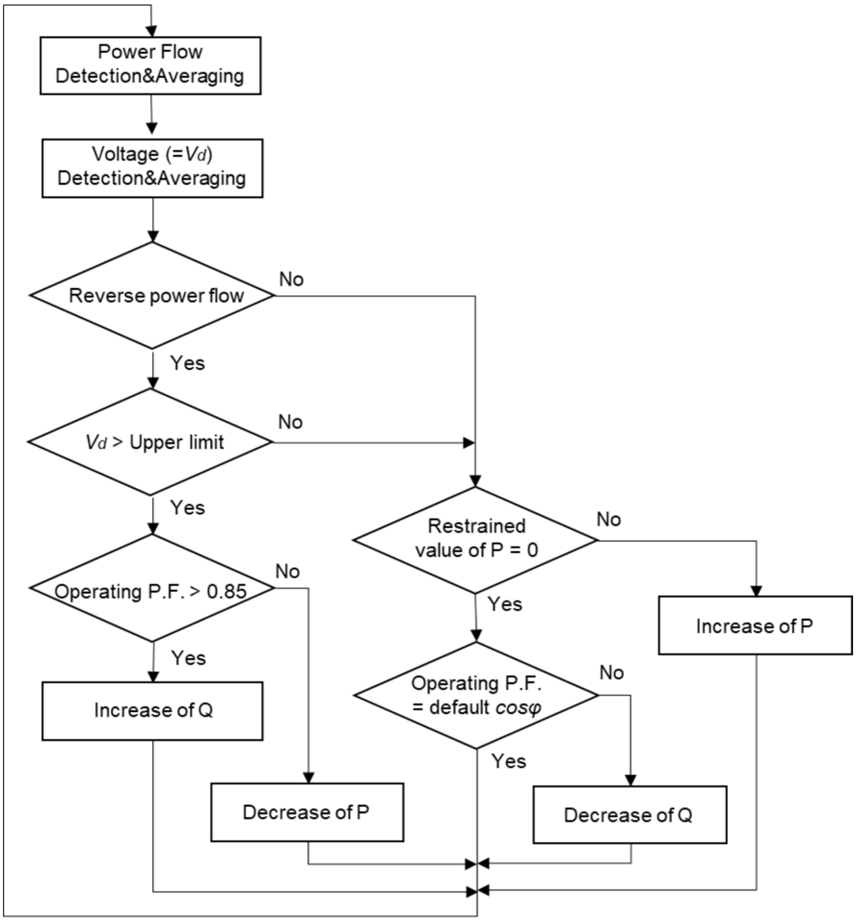


Figure 6: Typical control flow diagram for restraining voltage rise in low voltage distribution systems.

1. PCS of DER monitors the voltage (V_d) of the interconnection point of low voltage and detects whether the voltage exceeds the upper limit or not. In the case of power feeding into the grid from DER, in general, the power factor at the interconnection point should be 0.85 or higher, and it is necessary to avoid the leading power factor viewed from the grid, which means the lagging power factor viewed from the generation side, is required to prevent voltage rise.
2. If voltage V_d exceeds the upper limit and the operating power factor (P.F.) of the PCS is above 0.85, the inductive reactive power (Q) of PCS increases until operating P.F. reaches 0.85 and the voltage V_d is restrained within allowable level. If voltage V_d still exceeds the upper limit when operating P.F. reaches 0.85, the active power of PCS decreases until voltage V_d is restrained below the upper limit.
3. If voltage V_d is below upper limit and restrained value of active power of PCS is not 0, the active power of PCS increases until restrained value of active power becomes 0.
4. If voltage V_d is below the upper limit and operating P.F. is not equal to default setting value (cos φ = 0.95), the reactive power of PCS decreases until the P.F. reaches default cos φ.

While the current voltage control is conducted by such fixed power factor control and it has enabled suppressing voltage rises and smooth interconnection, in the NEDO project, due to the increase in the amount of PV interconnection in the distribution system, it was suggested that the current low voltage PV power factor value (0.95) may make it difficult to maintain an appropriate voltage depending on the medium-voltage PV fixed power factor value. Based on this result etc., "the power factor setting value must be changed according to the request of DSOs, with a function that allows it to be changed" was stipulated in the new grid code published in 2023 [16].

In addition to the voltage control function with reactive power control, the islanding detection method is also specified in the Grid-interconnection Code in Japan, and reactive power injection is used as the detection method.

2.4 Austria

2.4.1 Technical Framework

In Austria, the technical requirements for the connection of generators to the distribution grids is defined in the "Technical and organizational rules for operators and users of transmission and distribution networks (TOR)" [17]. The TOR represent the national grid code and are part of the so-called "market rules" for the national electricity market. The market rules are contractually binding for users and operators of electricity networks.

Out of the series of rules, the "TOR Erzeuger" (TOR Generating Systems, "Parallel operation of generation units connected to distribution networks") is of special relevance for the grid connection of generators. It addresses all aspects related to the connection and operation of generating systems in distribution grids, including installation, interface protection, active and reactive power control.

For the connection of generating systems, the requirements are defined based on the "generator type" as per the EU Regulation EU 2016/631 (Network Code Requirements for Generators). According to the relevant national directive ("RfG Schwellenwert-V") the national thresholds are defined as follows:

- Type A ≥ 0,8 kW
- Type B ≥ 250 kW
- Type C ≥ 35 MW
- Type D ≥ 50 MW or connected to networks ≥ 110 kV

Accordingly, different versions of the "TOR Generating Systems" are applicable (see [17] as starting point to the current versions):

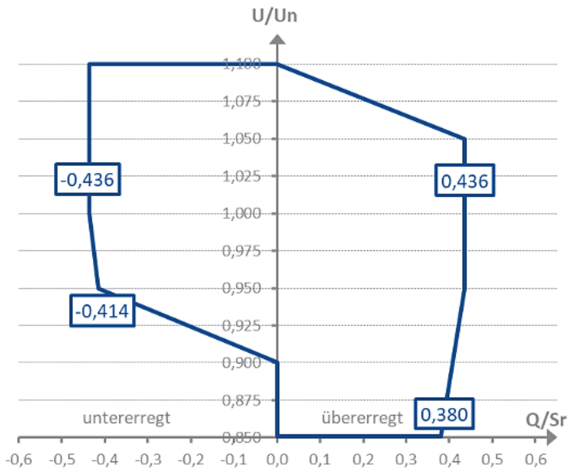
- TOR Erzeuger Typ A: Connection and parallel operation of generating system of type A and micro-generating plants (maximal capacity < 250 kW and nominal voltage < 110 kV) (see also [18])
- TOR Erzeuger Typ B: Connection and parallel operation of generating system of type B (maximal capacity ≥ 250 kW and < 35 MW and nominal voltage < 110 kV) (see also [19])
- TOR Erzeuger Typ C: Connection and parallel operation of generating system of type C (maximal capacity ≥ 35 MW and < 50 MW and nominal voltage < 110 kV)
- TOR Erzeuger Typ D: Connection and parallel operation of generating system of type D (maximal capacity ≥ 50 MW or nominal voltage ≥ 110 kV)

Besides technical requirements related to the installation and operation of the generating system, the "TOR Generating Systems" also specifies the requirements related to operational notification procedure, implementing the requirements of the European Network Code RfG.

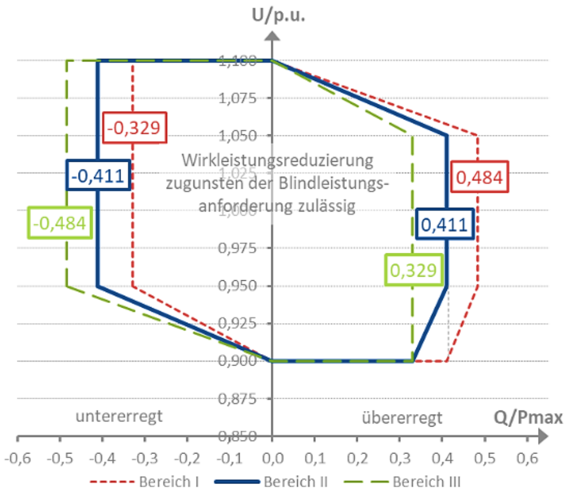
Austrian distribution network operators (DNOs) commonly follow the definitions of the "TOR Generators", however, they may specify individual settings of certain grid support functions, particularly related to voltage/reactive power control. The settings are usually specified by the DNOs based on the local grid situation and the capacity and technology of the generating system.

2.4.2 Requirements for Type A and Type B, LV and MV connected systems

Depending on the capacity of the generation plant and the network level (LV or MV), different requirements apply to the provision of reactive power. Generating units must be able to provide reactive power (LV: measured at the generator terminals, MV: at the point of connection) at maximum apparent power as per Figure 7.



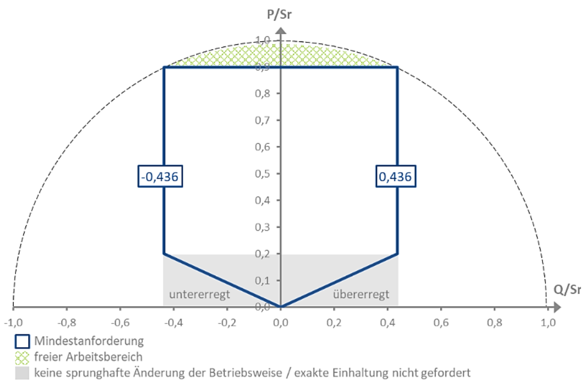
Type A, LV connection ([18], Figure 8)



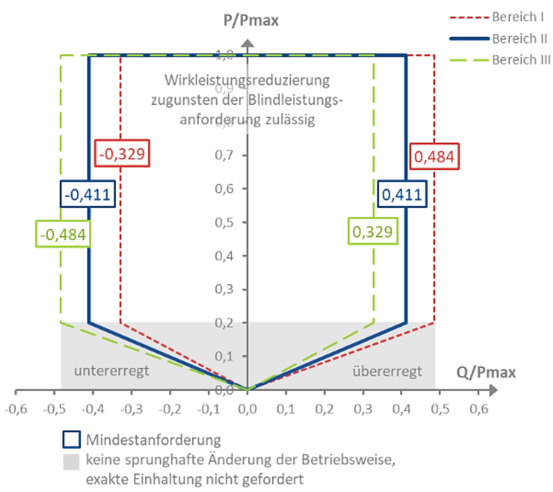
Type B, MV connection ([19], Figure 6): The range II represents the default range.

Figure 7: Reactive power requirements at maximum apparent power related to voltage ([18, 19]).

In the range $V < 0.85\ V_n$ and $> 1.1\ V_n$, reactive power shall be provided according to the capabilities of the generating units. Below the maximum apparent power, reactive power capability shall meet the requirements as shown in Figure 8.



Type A, LV connection ([18], Figure 8)



Type B, MV connection ([19], Figure 7)

Figure 8: Reactive power requirements below maximum apparent power ([18, 19]).

In the green marked area, a reduction of the active power output is allowed. It is allowed to reduce active power output in order to provide the required reactive power (reactive power priority). Reactive power is referenced to the rated apparent power capability of the generating unit (S_r). For active power levels < 0.2 P/S_r (grey marked area), the reactive power must not change abruptly, there is no requirements for the exact provision of the reactive power. If possible, the generating system shall maintain a minimum cos φ = 0.4 at active power levels < 0.2 P/S_r (indicated by the blue line in the figures above).

2.4.3 Reactive power control modes

Reactive power shall be controlled through one of the following modes, which are specified by the local DNO during the planning of the grid connection:

- Fixed cos φ: If this mode is selected, the generating unit shall operate at a fixed cosφ setpoint.
- cos φ (P): Low-Voltage connected generating systems: The generating unit shall absorb reactive power depending on the current active power output. The default cos φ (P) curve is provided in Figure 9.

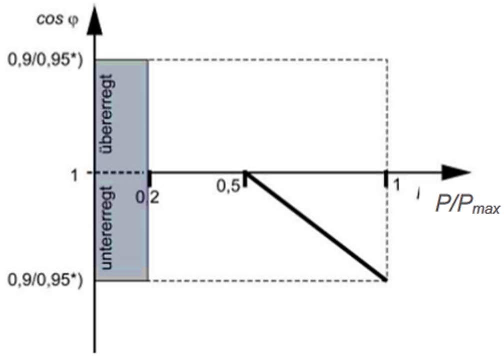


Figure 9: Default cos φ **(*P*) curve ([18], Figure 12).**

- *Q*(*V*) characteristic: The generating unit shall inject/absorb reactive power depending on the voltage (In LV, reference voltage shall be the highest phase-to-neutral voltage) at the generator terminals. Time response of the reactive power shall follow a first-order filter (PT1), with a time constant configured in the range of 3 s and 60 s (default: 5 s). The *Q*(*V*) shall be activated immediately following a change of the setpoint, with an initial delay less than 1 s). Any intentional delay shall be deactivated or set to 0. The default Q(V) curve is provided in Figure 10.

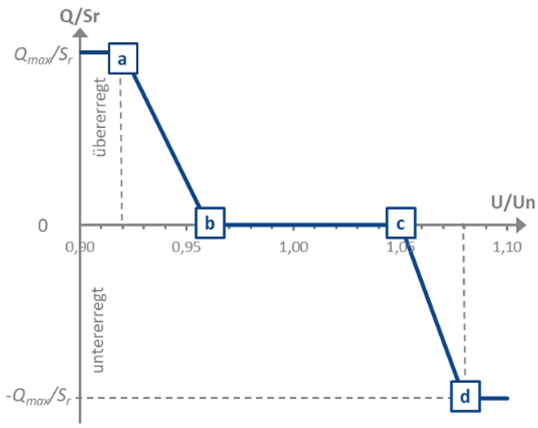


Figure 10: Default *Q*(*V*) characteristic ([18], Figure 13).

- Fixed *Q*: If this mode is selected, the generating unit shall operate at a fixed reactive power setpoint.
- Remote setpoint: For MV connected generating systems, the network operator may also request fixed values based on a (time) schedule. Upon agreement, the network operator may also request fixed values or the change of the control mode via a remote-control interface. Upon agreement, the network operator may also request fixed values for the reactive power or the change of the reactive power control mode via a remote-control interface.
  For generating systems < 1 MW, the remote control will be implemented using dry contacts, as agreed upon in the contracts between the network operator and the user.
  For generating systems ≥ 1 MW, the remote control will be implemented using state-of-the-art communication standards (e.g., IEC 60870-5-101 or IEC 60870-5-104), as agreed upon in the contracts between the network operator and the user.

If no other provisions are given by the DNO, the default setting shall be cos φ = 1.

2.5 Italy

In Italy, current grid code defines reactive power regulation for generators directly and indirectly connected to the National Transmission Grid (NTG), also including PV and wind sources [20].

2.5.1 Reactive power regulation for RES directly connected to NTG

The reactive power control of directly connected sources [20] is based on capability curves at the PCC, both for connection to NTG portion with nominal voltage equal or greater than 110 kV (Type 1 production units) and for connection to NTG buses with nominal voltage equal to 36 kV (Type 2 production units). These curves are defined for PV and wind plants in the Italian Grid Code Annex 68 [21] and Annex 17 [22], respectively. In detail, Type 1 PV sources have to continuously regulate the reactive power control according to the capability curve reported in Figure 11.

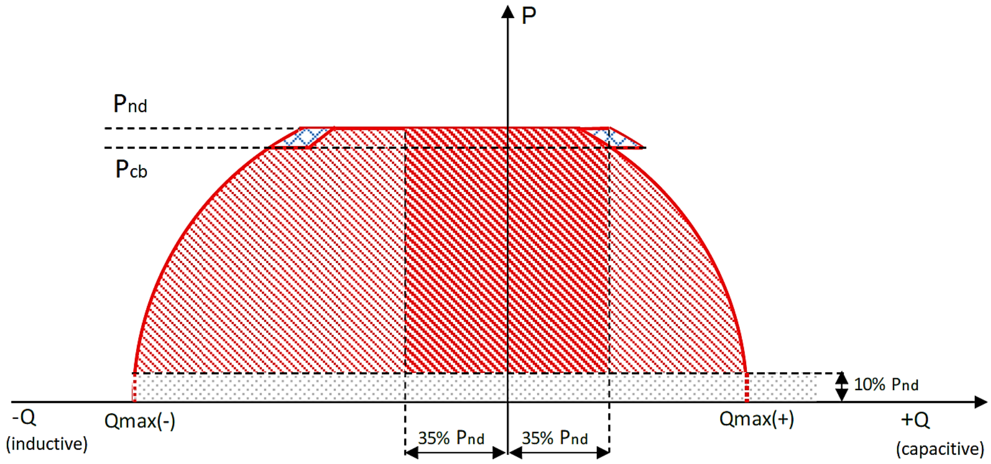


Figure 11: Requirements on reactive power provision capability for Type 1 PV plants [21].

In case of PV plants sourcing an active power greater than 10% of nominal available power P_{nd}, the capability limit in under-excitation conditions must be at least equal to 35% P_{nd} for each active power value (P_{nd} is equal to the nominal power of the PV plant (P_n) reduced by the nominal power of the not available inverters due to breakdown or maintenance operations.). The maximum reactive power is in the bent zone of the curve which depends on the considered specific plant. In over-excitation, the reactive power control has to guarantee 30% P_{nd} when the active power equals P_{nd}. For active power values lower than P_{nd}, the reactive power limit is on the semi-circular curved zone of the capability graph. Furthermore, on TSO request, capacitor banks can be connected to the NTG. They are inserted for power values higher than P_{cb} to partially compensate for the residual inductive losses, as indicated by the blue shaded area in Figure 11.

The reactive power regulation in case of active power lower than 10% P_{nd} depends on power management in the specific plant. If the reactive power can be sourced also in absence of active power, the reactive power limit is determined by the PV plant inverter specifications. Otherwise, it is gradually decreased until zero value if the reactive power cannot be provided in case of null active power.

As above mentioned, Type 2 PV production units are constituted by plants directly connected to NTG buses with nominal voltage equal to 36 kV. According to the Italian Grid Code Annex 68, these generators have to satisfy the capability curve reported in Figure 12.

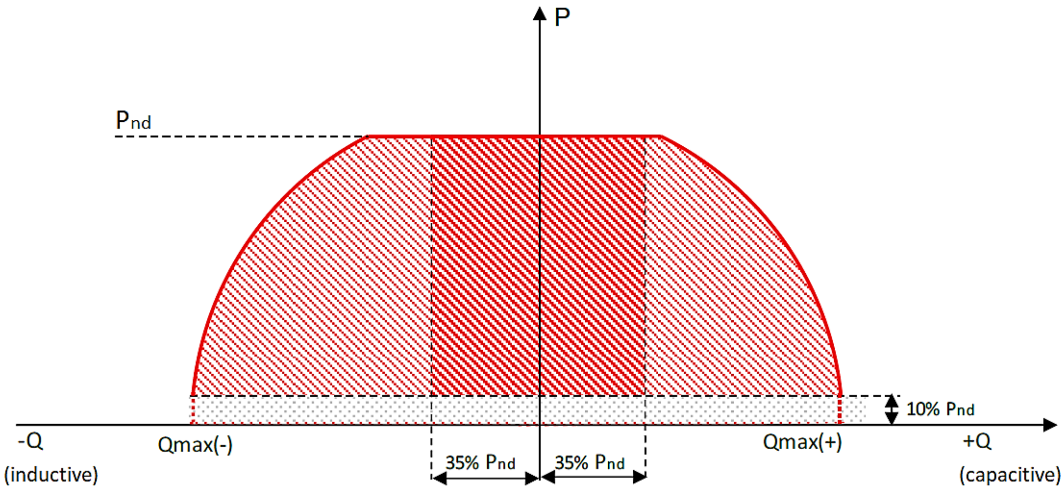


Figure 12: Requirements on reactive power provision capability for Type 2 PV plants [21].

In addition, adequate controllers equip the production units to the reactive power regulation according to specific set points. They can be locally, or real time defined by TSO. PV plants meters carry out measurement and data sending actions toward the TSO according to Grid Code timing and overshoot limits.

In the following figures, Annex 17 [20] capability curves are reported for Type 1 and Type 2 wind plants.

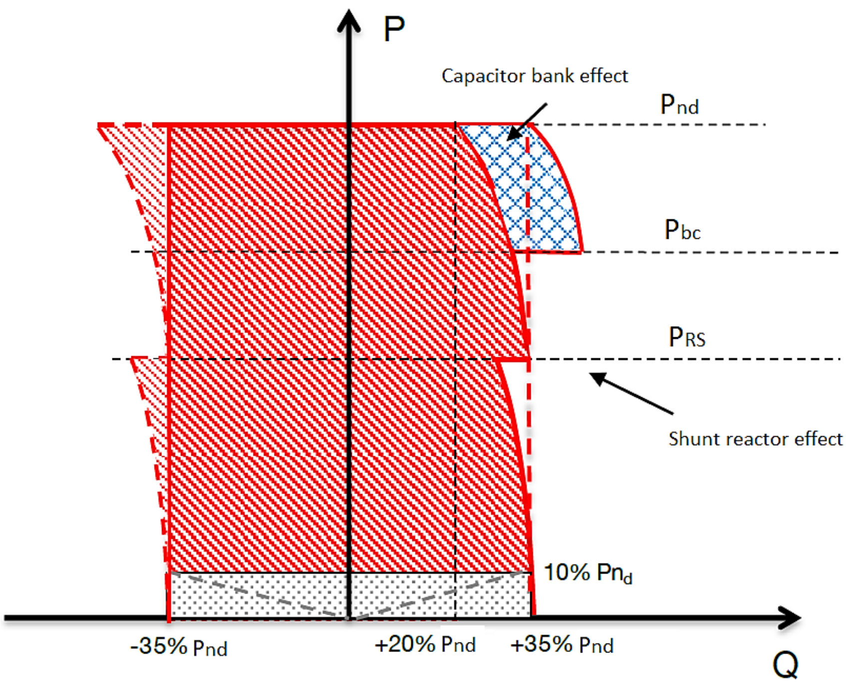


Figure 13: Requirements on reactive power provision capability for Type 1 wind plants [22].

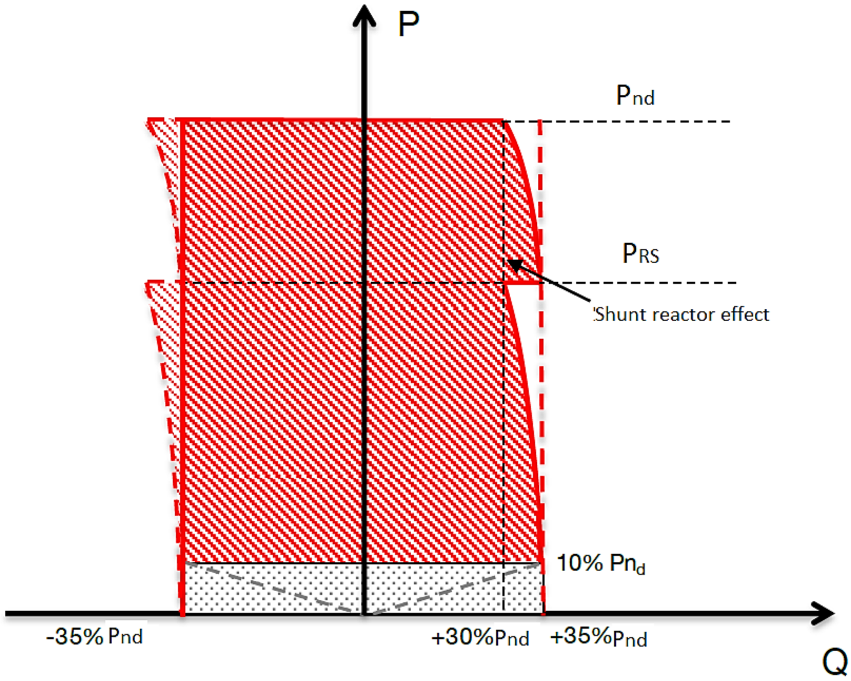


Figure 14: Requirements on reactive power provision capability for Type 2 wind plants [22].

2.5.2 Reactive power regulation for RES indirectly connected to NTG

Italian Grid Code classifies production units **indirectly** connected to the Transmission grid [20] as:

- Type 1: generators connected to the NTG through a grid portion with nominal voltage equal to or greater than 120 kV.
- Type 2: relevant generation units connected to the NTG through a portion of the grid with nominal voltage lower than 120 kV.
- Type 3: non relevant generators connected to the NTG through a grid portion with a voltage lower than 120 kV.

Type 1 plants are managed according to technical regulations for directly connected power generation units [20]. Also Type 2 sources work according to reactive power regulation rules for directly connected generators. In case of Type 3 plants, the capacity of reactive power variation has to satisfy the technical regulation reported in the Italian Electrotechnical Committee CEI 0-16 [23] and CEI 0-21 [24] normative documents.

CEI 0-16 constitutes the reference technical rules for the connection of active and passive consumers to the HV and MV electrical networks of distribution company [23]. It also includes local and remote logics which distributed generation (DG) plants have to implement at DSO request. In detail, one of the following control logics can be applied:

- Automatic reactive power sourcing/sinking according to $\cos\varphi = f(P)$ characteristic curve.
- Automatic reactive power sourcing/sinking according to $Q = f(V)$ characteristic curve.

2.5.2.1 Automatic reactive power sourcing/sinking according to cos φ = f(P) characteristic curve

Due to active power injection in the MV grid, voltage overvoltage and undervoltage conditions can occur. CEI 0-16 prescribes that all generators connected to MV grid must participate to the voltage control by reactive power sourcing or sinking actions. Since reactive power control increases power losses in MV lines, its regulation is activated only in case of grid voltage higher than a lock-in value (for example: $V_{lock\text{-}in} = 1.05\ V_{nominal}$). Considering MV grid portions and the sources features, the DSO defines the necessary (sourcing or sinking) operations and the nominal reactive power values within the capability limits (reported for different production units in CEI 0-16 Section 8.8.5.3). In particular, the reactive power has to be supplied by a local automatic controller and according to one of the following methods:

- a power factor curve function of active power cos $\varphi = f(P)$.
- a fixed and settable cos φ power factor.
- a DSO requested control logic.

The cos $\varphi = f(P)$ curve characterizing the former mode is reported in Figure 15.

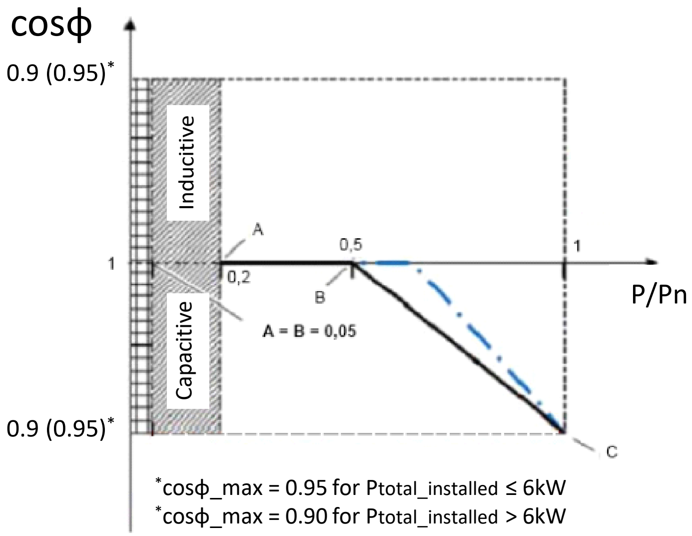


Figure 15: ENEA5 cos $\varphi = f(P)$ standard curve [23].

Static generators must work according to the above represented curve guaranteeing the reactive power regulation at their converter's terminals within 10 s. In case of a production unit providing an active power equal to 50% of the nominal power P_n ($P = 0.5\ P_n$) and the relative voltage V_{rel} at the converter output results lower than a lock-in value $V_{lock\text{-}in}$, the generators work with cos $\varphi = 1$. In operative conditions characterized by converters voltage V higher than $V_{lock\text{-}in}$ value, the reactive power is regulated according to curve shown in Figure 15 within 10 s. This control stops its action as soon as the voltage V becomes lower than a lock-out value $V_{lock\text{-}out}$ or in operative conditions with $P < 0.5\ P_n$ regardless of the terminal voltage value. It is noting that $V_{lock\text{-}in}$ and $V_{lock\text{-}out}$ are DSO defined values.

In addition, the reactive power regulation is activated also in case of $P > 0.5\ P_n$ with voltage level higher than allowed limits. In such case, the plant operative conditions are modified in order to match the standard curve in the actual active power (within 10 s). This curve can be modified by DSO depending on grid, load type and injected power. Blue dotted lines report a variant to the standard curve in Figure 15.

Referring to the second method with a fixed power factor, it is underlining it constitutes the default mode for Full Converter and Doubly Fed Induction Wind Generators.

Furthermore, on DSO request (third method), the wind production units must match the cos $\varphi = f(P)$ curve reported in Figure 15. Such mode has to be enabled either locally or remotely via a control interface.

2.5.2.2 Automatic reactive power sourcing/sinking according to Q = f(V) characteristic curve

The CEI 0-16 document also prescribes reactive power sourcing/sinking operations in dependence of grid voltage value. Such regulation must be assured in accordance with a characteristic $Q(V)$ curve and it is activated by local settings or remote DSO requests.

In case of static generators up to 6 MW, the $Q = f(V)$ curve is represented in Figure 16. It is characterized by positive reactive power in sourcing mode (over-excitation) and negative reactive power in sinking one (under-excitation). $+Q$ and $-Q$ limits are defined by the generator capability curve (Section 8.8.5.3 of CEI 0-16) while k parameter is defined during the system configuration process. In operative modes characterized by $V > V_{1s}$ or $V < V_{1i}$, the plant converter verifies the active power value. In case of $P < P_{lock\text{-}in}$, the generator works with cos $\varphi = 1$. If P results higher than the lock-in power limit ($P > P_{lock\text{-}in}$), the converter regulates the reactive power matching the $Q(V)$ curve within 10 s. This control finishes its action in case of $P < P_{lock\text{-}out}$ regardless of voltage value or in operative conditions characterized by the terminal voltage in the ($V_{1s} < V < V_{1i}$) range.

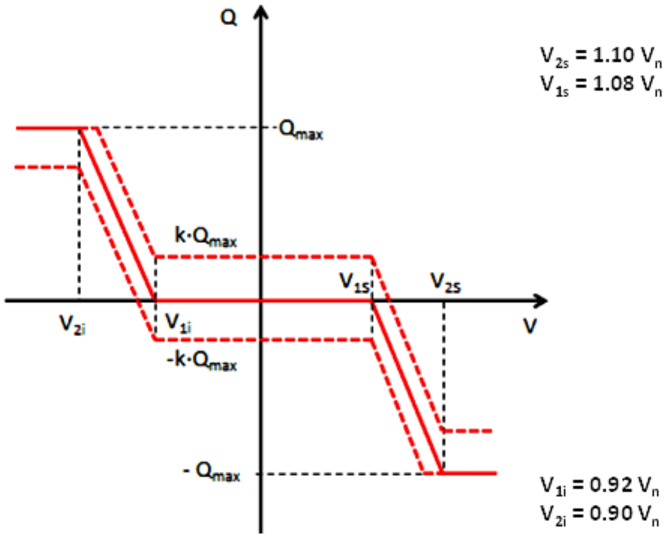


Figure 16: $Q = f(V)$ standard curve [23].

The $Q = f(V)$ curve for static generators with power higher than 6 MW have the same shape represented in Figure 16, but their operative points change as reported in the following:

- $V_{1i} = 0.95\ V_n$
- $V_{2i} = 0.90\ V_n$
- $V_{1s} = 1.05\ V_n$
- $V_{2s} = 1.10\ V_n$

Finally, the reactive power regulation for LV production units is prescribed in CEI 0-21 [24] which constitutes the reference technical rules for the connection active and passive users to the LV electrical utilities. Also, in LV sources the automatic reactive power sourcing/sinking operations are conducted according to cos $\varphi = f(P)$ or $Q = f(V)$ characteristic curves.

The CEI 0-21 document reports P/Q capability curves and characteristic (cos $\varphi = f(P)$ or $Q = f(V)$) curves for different production units. Annex E provides details, operative modes and working points for plants whose power results lower or equal to 11.08 kW (only cos $\varphi = f(P)$ control mode) and for plants whose power is higher than 11.08 kW (cos $\varphi = f(P)$ and $Q = f(V)$ control modes).

3 DER BASED REACTIVE POWER CAPABILITIES

Reactive power control by DER implementation can vary relatively between different DSOs. This chapter introduces some reactive power control and management strategies that have been investigated in various research studies.

3.1 Coordination between TSO and DSO

In this section, the technical and regulatory aspects of coordinating reactive power between TSO and DSO as part of grid management will be discussed. There are many national and international regulations and guidelines in place for cooperation between grid operators and consumers at the cross-grid and cross-border level. At the European level, the "Demand and Connection Code (DCC)" and the regulation on transmission system operation are particularly noteworthy [25]. In 2016, the ENTSO-E adopted a dedicated guideline "Reactive Power Management at T-D Interface" specifically for managing reactive power at the TSO-DSO interface. Additionally, organizations such as ENTSO-E and others (e.g., E.DSO for the DSO) have released studies, guidelines, and position papers highlighting the significance of this topic. These regulations are laid down on DCC, that specifically regulates how the distribution systems directly connected to the transmission system should respect the reactive power limits in normal operation.

As depicted in Figure 17, the limitations on the amount of reactive power that consumers and distribution grids can produce or consume are established in accordance with guidelines set by ENTSO-E-DCC and Swiss grid. Swiss regulations are referenced because they also compensate for reactive power.

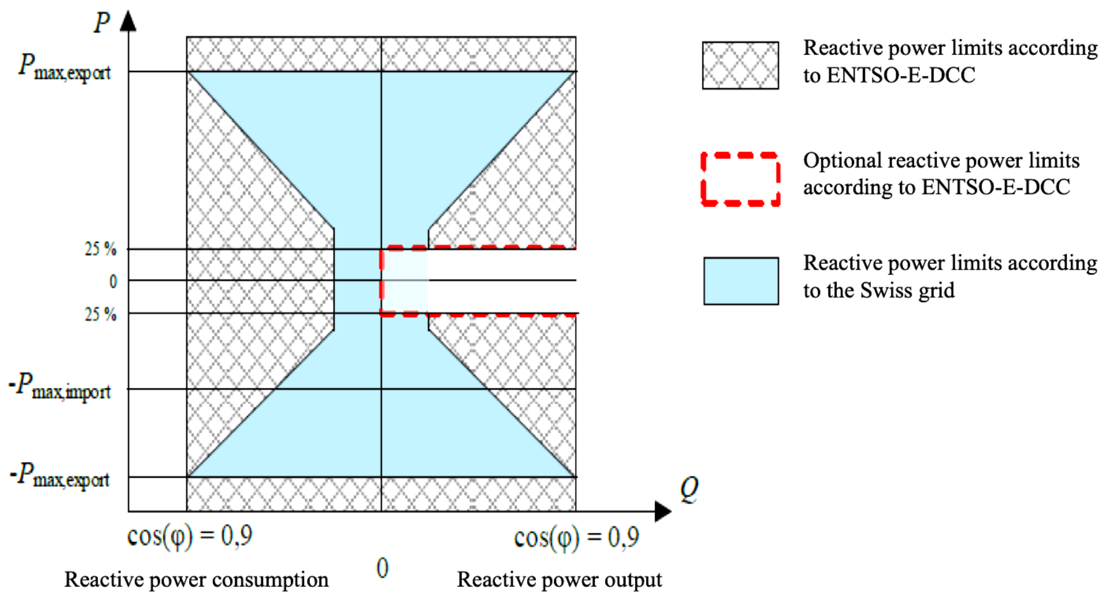


Figure 17: Reactive power limits of loads and distribution systems with the transmission system according to ENTSO-E-DCC [25] and to a Swiss regulation [26].

The shaded area in the diagram represents the range of permissible values as per ENTSO-E-DCC. The hatched area is surrounded by a dashed line and represents an optional limitation according to the DCC. The DCC specifies that the relevant TSO may decide that distribution systems connected to the transmission system should not be able to inject any reactive power at the point of connection to the grid (at a reference voltage of 1 p.u.) if the active power flow is less than 25% of the maximum reference capacity. In Switzerland, Swiss grid has developed a concept which compensates DSO if they provide reactive power to the grid. These limits of the Swiss concept [15] are shown in blue in Figure 17. Whether compensation is paid in Switzerland still depends on the respective demand situation of the TSO. If the actual voltage (V_{act}) at the grid interconnection point in the TSO is above the target voltage (V_{set}), then a reactive power consumption is remunerated by the TSO. If the actual voltage (V_{act}) is lower than the set point voltage (V_{set}), reactive power consumption is compensated by the distribution system.

Figure 18 illustrates the principles for determining whether reactive power input and output should be compensated for. The voltage deviation ΔV_{dev} is shown, and it represents the range of allowable deviation (±2 kV for 220 kV and ±3 kV for 380 kV) within which compensation is not given. If the voltage V_{act} falls outside of these limits in the compliant regions, then the integral reactive power W_Q measured over 15 minutes is compensated. No compensation is provided if the voltage deviation falls outside of these limits in the non-conforming regions.

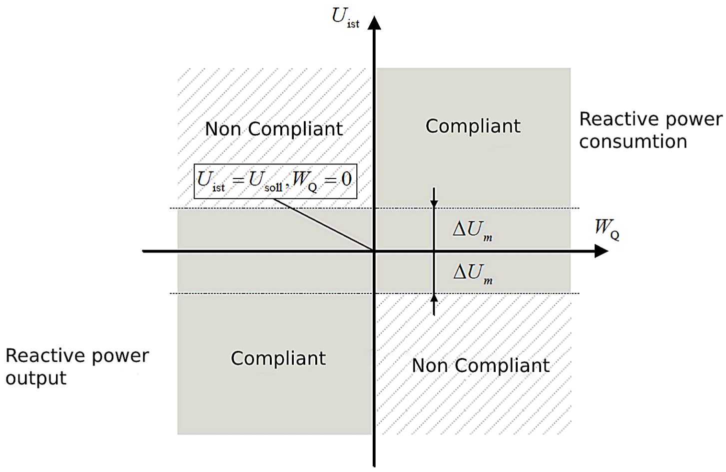


Figure 18: Principles of compliance of reactive power input and output of the Swiss regulation [26].

3.2 Reactive power support by DER

3.2.1 Changes of the German power system due to high DER penetration

The penetration of variable and intermittent DERs especially wind and PV are rapidly increasing at the distribution level. This has resulted in a more variable and dispersed energy production within the German power system. Since renewable energy sources, such as solar and wind power plants, are spread out across different locations and primarily connected to the distribution level, the structure of the German power system has undergone significant changes and now displays a more decentralized layout. This is particularly evident during periods of high solar radiation or strong winds, when there is a flow of power from the distribution level back to the transmission level within the German power system as can be seen in [8].

As a result of the significant uptake of renewable energy sources and the resulting bidirectional power flow in the German power grid, German DSOs are currently confronting different challenges like reactive power balancing issues at the grid interfaces and voltage problems and violations.

The difficulties result in extra expenses for both DSOs and TSOs in Germany. To guarantee a dependable electricity supply and minimize the need for investment, particularly in an energy system with a high proportion of renewable energy sources, German DSOs and TSOs are investigating viable alternatives, such as reactive power management and control.

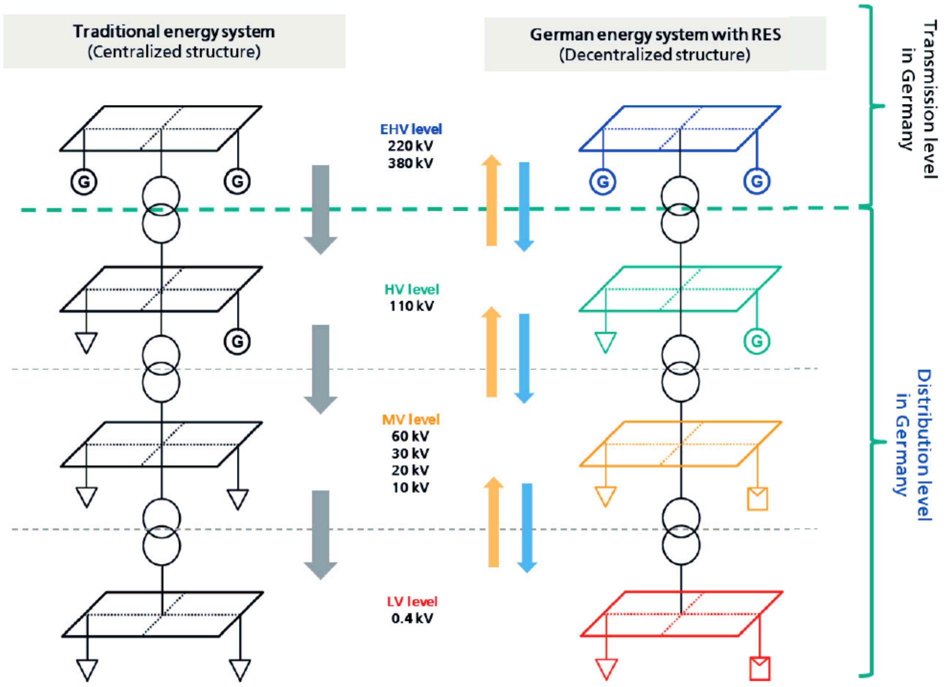


Figure 19: German energy system changes due to increased penetration of RES [2].

3.2.2 Case study: Reactive power support potential by DERs

The objective of this research study is development and discussion on transparent and comparable performance indicator for the availability of DER reactive power support in reactive power grid adequacy studies. Key Performance indicators include Reactive flexibility hours (*RFH*), Reactive capacity credit (*rCC*), reactive energy credit (*REC*).

3.2.2.1 Time series model

The passage is discussing the use of a time series model to analyze the reactive power support potential of DER in a distribution network. The model considers the reactive power capability of the DER and their active power feed-in, considering forced outages, maintenance intervals, and market operation.

The model assumes that the reactive power support of all DER types is modeled as a negative reactive power demand, depending on the type of support required (underexcited or overexcited operation). The reactive power support potential of DER is derived from the considered DER reactive power capability and coincident feed-in data, which allows for the consideration of complex correlations between reactive power support potential of different DER units and the reactive power support demand in the case study area.

The time series approach is relatively simple to apply but requires several years of analysis to derive robust results. It can be used for all DER types and is particularly useful for DER with variable reactive power support potential, such as those with fixed power factor and fixed reactive power capability. For the DER with STATCOM capability a perfect reliability is assumed (full reactive power potential for all annual hours). The data is provided in 15 minutes or one hour resolution and for the theoretical and technical assessment one hour time resolution is applied in the time series model. Therefore, 15 minutes data is re-sampled by the hourly mean value.

3.2.2.2 Reactive flexibility hours (RFH)

The RFH is a measure that quantifies the total number of hours in a year that a distributed energy resource (DER) can provide reactive power support within specific operational limits, such as full or partial range reactive power support. The *RFH* does not consider the reactive power demand in the grid section. It is particularly useful when assessing the potential for DERs to provide reactive power support in a specific grid section, where the demand is not known.

The reactive flexibility hours, as outlined in [27], are as follows explained:

- Reactive flexibility hour *RFH*: sum of annual hours with any DER reactive power support potential.
- Partial-range reactive flexibility hours RFH_{part}: sum of annual hours with reactive power support potential above zero and below the nominal DER reactive power support capability.
- Full-range reactive flexibility hours RFH_{full}: sum of annual hours with nominal DER reactive power support capability.

The DER reactive power support capacity in the time-based model is determined by analyzing active power measurement data from the DER units, which takes into account both unplanned outages (such as forced outages) and scheduled outages (for example, maintenance for “PF fix” and “Q fix” capability). The STATCOM capability is assumed to have complete flexibility throughout the entire year. Additionally, this model also incorporates a probabilistic approach to assessing reliability. The full-range reactive flexibility hour $RFH_{\mathrm{full}}^{\mathrm{prob}}$ can be calculated using equation 1, where T_{year} is the total number of annual hours and FOR_{DER} is the forced outage rate (probabilistic reliability model) of the generators.

$$\boldsymbol{RFH_{\mathrm{full}}^{\mathrm{prob}}} = (\mathbf{1} - \boldsymbol{FOR_{\mathrm{DER}}}) \cdot \boldsymbol{T_{\mathrm{year}}} \tag{1}$$

The annual partial-range reactive flexibility hour $RFH_{\mathrm{partial}}^{\mathrm{prob}}$ partial for the probabilistic reliability model is set to zero, as the model only considers two possible states ($Q_{N,\mathrm{DER}}$ or zero).

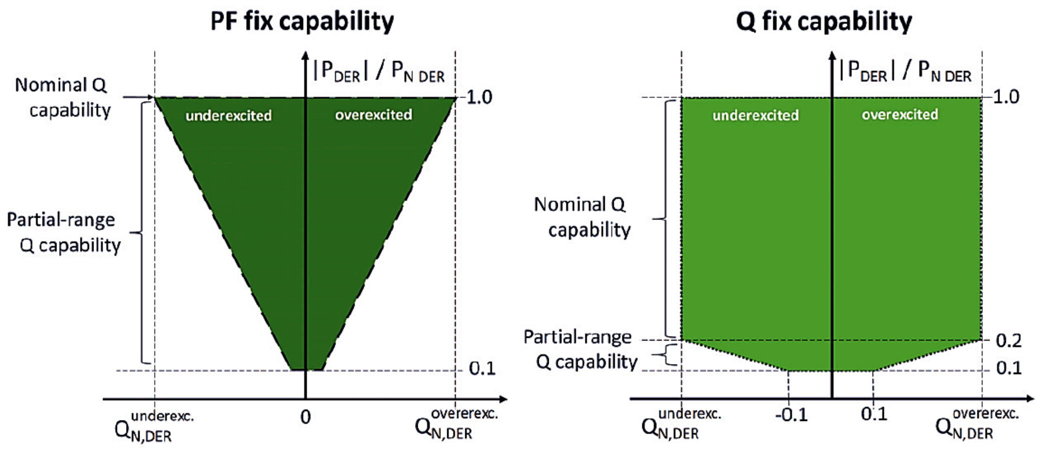


Figure 20: Specification of reactive power potentials for PF fix (left) and Q fix (right) capabilities [27].

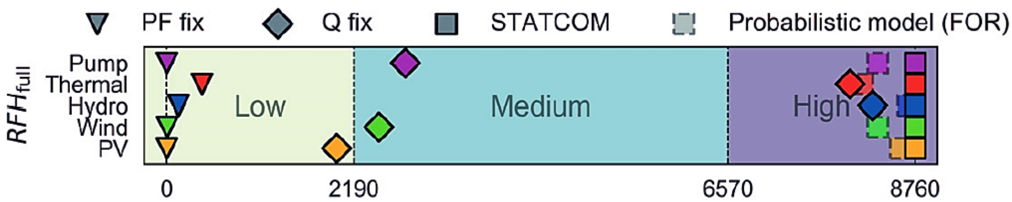


Figure 21: Overview of full range reactive flexibility hours [27].

Figure 21 illustrates the full range of reactive flexibility hours (RFH_{full}) for various types of DER and their Q(P) capability characteristics. In general, Hydro and Thermal DER with fixed reactive power capability and all DER types with STATCOM capability have the highest RFH_{full} values. However, the RFH_{full} for the probabilistic generator model is slightly lower than the STATCOM capability in the time series model due to the inclusion of forced outage rates of the generators.

3.2.2.3 Reactive capacity credit (rCC)

The reactive capacity credit is a measure of how much support DER reactive power provides to ensure there is enough reactive power in a specific section of the grid. It predicts how well DER reactive power can provide support during the time of the year when the highest amount of undesired reactive power exchange occurs at the T-D interface, whether it is import or export. The rCC can be calculated for diverse levels of compliance targets at the T-D interface, such as 100% or 98% of annual values. This performance indicator, *rCC*, is particularly useful when there is a fixed target level for the reactive power exchange at the T-D interface.

The *rCC* can be calculated for various levels of compliance targets (denoted as t_{req}) concerning the reactive power exchange at the T-D interface. For instance, Figure 22 illustrates the determination of *rCC* for the 0th percentile ($rCC_{Sx,p0}$), representing the maximum annual deviation of $devQ_{T\text{-}D}$ for the specific scenario. When conducting adequacy studies for reactive power grids, an exclusive emphasis on annual extreme values and extremely high compliance target levels may not be advisable. This caution arises from the fact that such extreme values can result from rare events and unconventional switching configurations within the grid section. Additionally, addressing reactive power inadequacies at the distribution level may involve supplementary measures. Consequently, alternative compliance target levels (in this case, the 2nd and 5th percentiles of annual time steps) for *rCC* are also derived. For a better comparability of different DER units or DER types the *rCC* is normalized by the total nominal reactive power capacity $Q_{N,\mathrm{DER},Sx,\mathrm{sum}}$ of the considered DER systems in S_x.

$$rCC_{S_x}(t_{\mathrm{req}}) = \frac{devQ_{\mathrm{T-D},S_0}(t_{\mathrm{req}}) - devQ_{\mathrm{T-D},S_x}(t_{\mathrm{req}})}{Q_{N,DER,Sx,sum}} \qquad [\mathrm{pu}] \tag{2}$$

$$rCC_{S_x}(t_{\mathrm{req}}) = devQ_{\mathrm{T-D},S_0}(t_{\mathrm{req}}) - devQ_{\mathrm{T-D},S_x}(t_{\mathrm{req}}) \qquad [\mathrm{Mvar}] \tag{3}$$

where:

$$rCC_{S_x,\mathrm{p}_0} \quad \text{with} \quad t_{\mathrm{req},p_0} = 0 \cdot T_{\mathrm{year}} = 0 \ \mathrm{h/year}$$
$$rCC_{S_x,\mathrm{p}_2} \quad \text{with} \quad t_{\mathrm{req},p_2} = 0.02 \cdot T_{\mathrm{year}} = 175 \ \mathrm{h/year}$$
$$rCC_{S_x,\mathrm{p}_5} \quad \text{with} \quad t_{\mathrm{req},p_5} = 0.05 \cdot T_{\mathrm{year}} = 438 \ \mathrm{h/year}$$

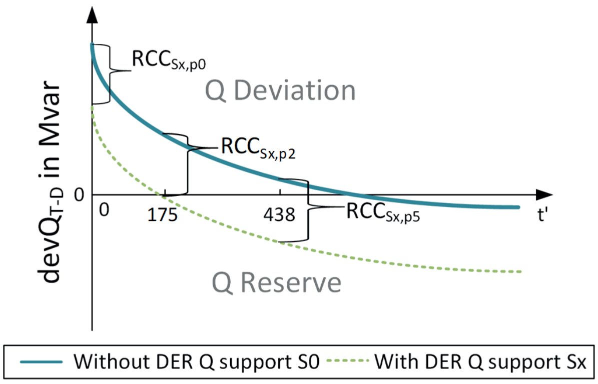


Figure 22: Methodology for the determination of the reactive Capacity Credit (*rCC*) [27]

Figure 23 gives an overview of the rCC_{p2}, which is the compliance target for 98% of annual values, for different types of DER and their Q(P) capability characteristics. The Hydro DER and some Thermal DER with reactive power fix capability, as well as all types of DER with STATCOM capability, have high rCC_{p2} values. Additionally, PV DER have a medium rCC_{p2} with Q(P) capability and the reactive power import use case since a high reactive power import only occurs with high PV generation in the grid section. The rCC_{p2} for the probabilistic generator model are lower than those for STATCOM capability in the time series model, as they consider the forced outage rates of the generators.

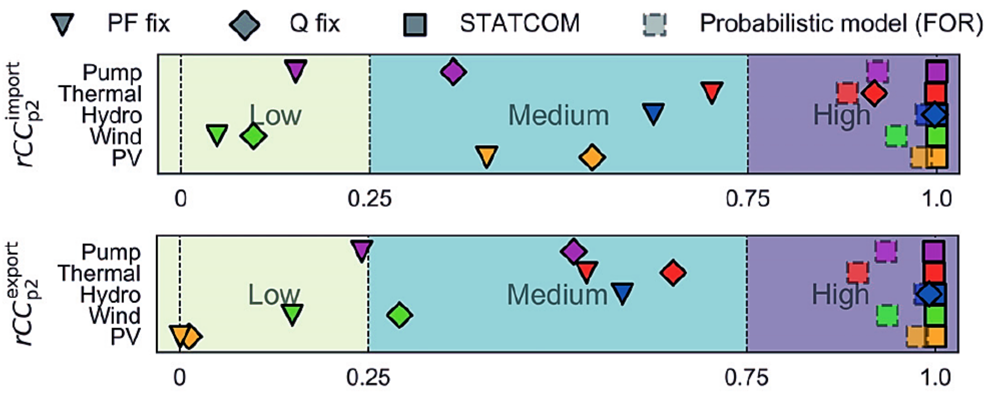


Figure 23: Overview of reactive power capacity credits for different DER and Q(P) capability characteristics [27].

3.2.3 Case study: Forecasts for the reactive power flexibility potential of PV plants

3.2.3.1 Introduction

Currently in Germany, there is a discussion regarding the use of a fair, open and transparent procedure to procure reactive power [28]. This makes it increasingly important for distribution grid operators to anticipate the demand for reactive power and the potential for flexibility in their service area. Another example involves the centralized management of reactive power for all photovoltaic power plants exceeding 500 kWp within a particular section of the grid. The main objective of this case is to forecast the active power supply and reactive power flexibility potential for a single large MV PV plant with a capacity of $P_{N,\mathrm{PV}} = 1.82\ MWp$.

3.2.3.2 Simulation environment

A simulation environment has been created for a genuine section of the MV grid located in the southern region of Germany, which is distinguished by a significant penetration of PV. This portion of the grid is summarized, and the steps taken to prepare time series data and verify the accuracy of the simulation environment are explained.

The MV grid under investigation, which operates at a voltage of 20 kV, consists of two transformers that convert high voltage to medium voltage. There are also two main supply areas, one of which supplies power to a commercial area with large PV systems, while the other serves a rural region with mostly small rooftop PV systems (see Figure 24). Table 1 provides information on the installed capacity in this section of the grid, which includes not only PV generators but also biopower and combined heat and power plants (CHPs).

The investigation involves performing quasi-static time series simulations of the grid section for a period of 9 months, from January to September 2017, with a time resolution of 15 minutes. Initially, a simulation is created to reproduce observations of the grid section using representative measurement data for loads and several types of generation. Power estimates for PV units without measurements are calculated using satellite data, while representative measurement profiles from the SimBench Project [29] are used for loads without measurement data, based on the standard load profile type and expected annual energy consumption. The observation simulation is validated using power flow measurement data at the HV/MV transformer and is used as a reference for evaluating different grid forecasting simulations.

The grid forecasting simulations focus on the impact of improved PV power forecasts, but also consider forecasting errors for loads and other DER types in a practical manner. Average daily profiles are applied for loads and other generators (except PV) in the grid forecasting simulations, depending on the season and day type (workday or non-workday for loads). The grid forecasting simulations differ only in the approach used for PV forecasting. The following approaches are considered:

- CharDF: This method applies an average characteristic day profile for PV generators in the grid section, based on the annual season. It is a simple forecasting method that relies solely on historical experience values and measurements from the investigated grid.

- SDAF: For PV units, a standard day-ahead forecast (SDAF) is applied based on numerical weather prediction (NWP) data. However, the PV power forecast is not optimized for the investigated grid section, considering the slope and orientation of the PV units.
- ADAF10: This approach uses an advanced day-ahead forecast (ADAF) based on NWP and real-time satellite data for PV units. The ADAF is simulated by combining forecasted irradiance from NWP models with 10% of irradiance derived from satellites. For PV units with measurement data, an optimized slope and orientation is applied.
- ADAF20: Like ADAF10, but with 20% of satellite-derived irradiance data mixed into the forecasted irradiance.
- SIDF: A standard intraday forecast (SIDF) is applied for PV units, with a forecast horizon of one hour based on cloud motion vectors from satellites and NWP model data. However, the PV forecast is not optimized for the investigated grid section.

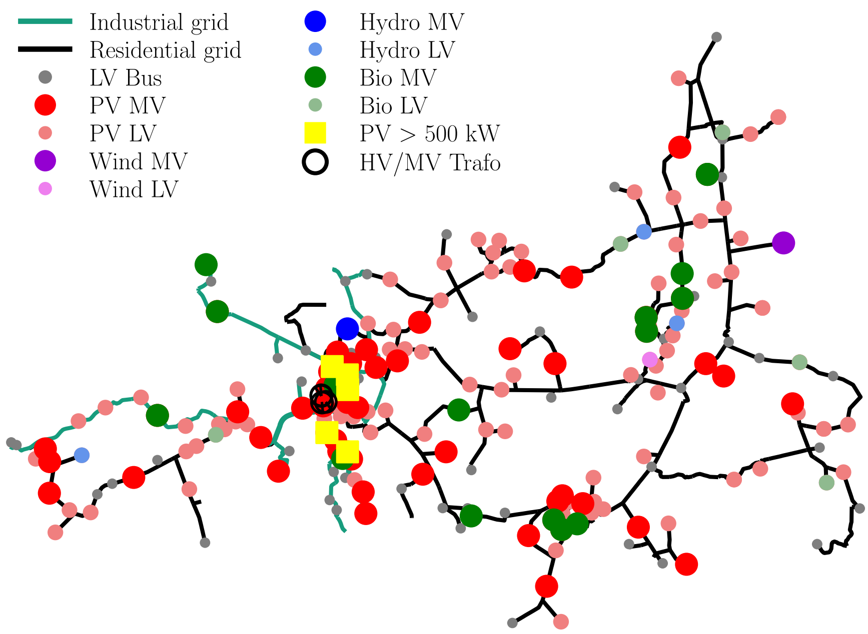


Figure 24: Investigated MV grid section[30].

Table 1: Installed capacity of investigated grid section [30].

	PV DER	Wind DER	Hydro DER	Bio & CHP	Peak Load
Capacity in MW	24.8	2.0	0.1	16.7	19.9

3.2.3.3 Scenario definition

Reactive power capabilities of the plant that are considered:

- Cosphi capability: minimum power factor capability (see Figure 25, left, black line). This is the minimum capability according to the former German MV guideline.
- VDE4110 capability: capability according to the current German MV grid code VDE AR-N 4110 (see Figure 25, right, black line). Constrained reactive power capabilities (with reactive power potential reserve) for the MV PV are applied in subsection 4.3 (see Figure 25, right, grey dashed lines).

To evaluate the reactive power flexibility potential, the highest overexcited and underexcited potentials are calculated over a simulation period of 9 months. The PV plant is situated close to the HV/MV substation, and issues with voltage violations and line congestion are not considered when determining the maximum overexcited and underexcited PV reactive power. As a result, only the active power feed-in affects the plant's maximum reactive power flexibility potential. The plant has the same absolute reactive power flexibility potential for both overexcited and underexcited operations.

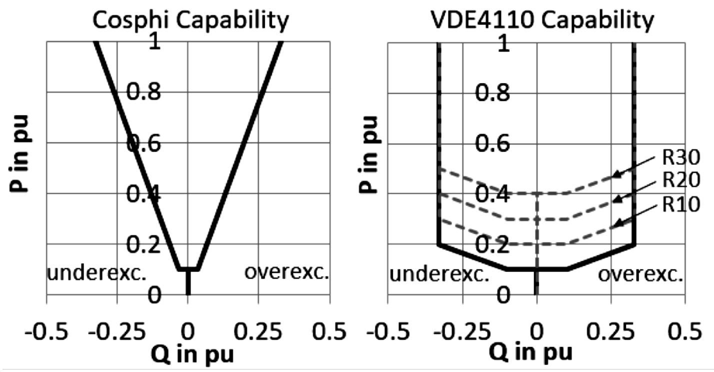


Figure 25: Considered MV DER Q control and Q capability characteristics [30].

3.2.3.4 Assessment of PV reactive power forecast errors

Figure 26 shows the PV feed-in and the resulting reactive power flexibility potential for the observation simulation (black lines) and two PV forecasting methods (colored lines) for one day with significant forecast error. The per unit values are normalized by the installed PV capacity. For the cosphi capability (dashed lines, right), the PV active power forecast error directly affects the reactive power flexibility forecast error, due to the widely linear relationship of PV feed-in and maximum reactive power potential (see Figure 26, left). For the VDE4110 capability, no reactive power potential is available with PV feed-in below 0.1 p.u. and full reactive power potential is available with PV feed-in above 0.2 p.u. Consequently, significant reactive power flexibility forecast errors can appear with rather small PV feed-in forecast errors (see Figure 26, right, solid lines).

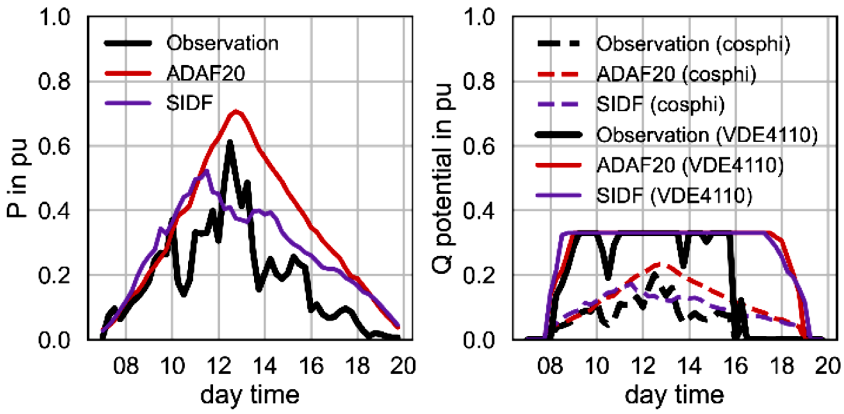


Figure 26: PV active power feed-in (left) and reactive power flexibility potential (right, overexcited) [27].

The MAE (mean absolute error) of PV active power feed-in and reactive power flexibility forecast for various PV forecast methods is presented in Figure 27. The reactive power flexibility forecast (cosphi capability) has an MAE that is approximately one third of the active power forecast MAE. However, the absolute reactive power flexibility forecast error is higher for VDE4110 capability compared to the cosphi capability. Despite this, the overall reactive power flexibility potential (accumulated energy base) is approximately 2.1 times higher for VDE4110 capability than for the cosphi capability. For the VDE4110 capability, the SDAF with 0.09 Mvar has the lowest MAE, while the CharDF with 0.13 Mvar has the highest MAE. The advanced day-ahead forecasts (ADAF10 and ADAF20) and the intraday forecast (SIDF) do not demonstrate any improvement compared to the standard day-ahead forecast (SDAF). The tilt and orientation of the PV systems are optimized for ADAF, resulting in optimized RMSE. However, this leads to an averaging of forecasted power values, which means that exceptionally low power values are over-estimated and not specifically optimized. This is not beneficial for this use case. This result shows the importance of use case dependent PV forecast optimizations. With the VDE-AR-N 4110 capability it is especially important to forecast low solar radiation times (e.g., fully cloudy days) accurately. The next chapter shows, how the reliability of the PV reactive power flexibility forecasts can be improved by simple reactive power capability reserve.

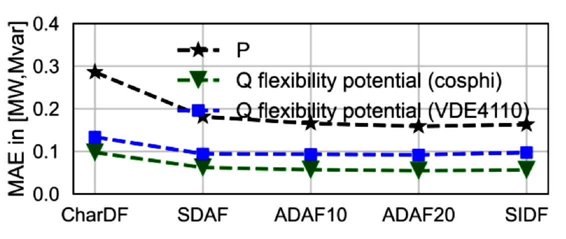


Figure 27: Mean absolute error of PV forecasting methods in daytime hours [27].

3.2.3.5 Improvement of PV reactive power flexibility forecast reliability

The distribution level's requirements for potential DER reactive power flexibility forecasting have not been established. Nevertheless, it is anticipated that high reliability forecast requirements will be necessary for using DER reactive power support as an ancillary service. This section examines the reliability of various reactive power flexibility forecasts using a basic reliability indicator $rel_{\mathrm{PV,flex}}(t)$ [27]

$$\boldsymbol{rel}_{\mathbf{PV,flex}}(\boldsymbol{t}) = \begin{cases} \mathbf{1}, & \mathbf{if}\ \left|\boldsymbol{Q}_{\mathbf{PV,flex}}^{\mathbf{forecast}}(\boldsymbol{t}) \leq \boldsymbol{Q}_{\mathbf{PV,flex}}^{\mathbf{observ}}(\boldsymbol{t})\right| \\ \mathbf{0}, & \mathbf{if}\ \left|\boldsymbol{Q}_{\mathbf{PV,flex}}^{\mathbf{forecast}}(\boldsymbol{t}) > \boldsymbol{Q}_{\mathbf{PV,flex}}^{\mathbf{observ}}(\boldsymbol{t})\right| \end{cases} \tag{4}$$

The reliability indicator $rel_{\mathrm{PV,flex}}(t)$ takes into consideration the necessity of preventing an overestimation of the forecasted reactive power flexibility potential $Q_{\mathrm{PV,flex}}^{\mathrm{forecast}}$ in comparison to the actual observed reactive power flexibility potential $Q_{\mathrm{PV,flex}}^{\mathrm{observ}}$ [30].

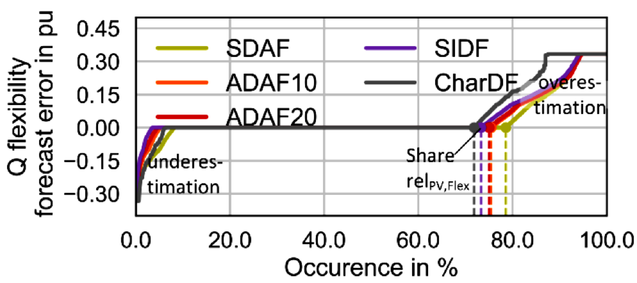


Figure 28: Duration curve of reactive power flexibility forecast errors (VDE4110) in day-time hours [30].

The percentage of accurate predictions for reliable reactive power flexibility (as shown by the dashed vertical lines in Figure 28) ranges from 72% (CharDF, VDE4110) to 79% (SDAF, VDE4110). Nevertheless, it is important to note that forecast errors for reactive power flexibility can be significant and may even reach the maximum potential of 0.33 p.u. for DERs for a considerable number of time steps.

In additional simulations, the forecast simulations take into account a decreased capability for reactive power (using the reactive power potential planning reserve R10, R20, R30 indicated by the dashed grey lines on the right side of Figure 29). The purpose of this reserve is to improve the reliability of the reactive power flexibility forecasts. By increasing the reserve, the reliability of the reactive power flexibility forecast is further enhanced (as seen on the left side of Figure 29). For instance, using the reactive power potential planning reserve R30 results in a reliable forecast of between 90% (CharDF) and 98.9% (SIDF). On the other hand, Figure 29 (right) reveals that all PV forecasting methods overestimate the reactive power flexibility potential (based on accumulated energy) when the reactive power planning reserve is not applied. The drawback of utilizing a planning reserve is that it reduces the forecasted reactive power flexibility potential, which means that less DER reactive power potential can be included in the operational planning processes of the grid operators.

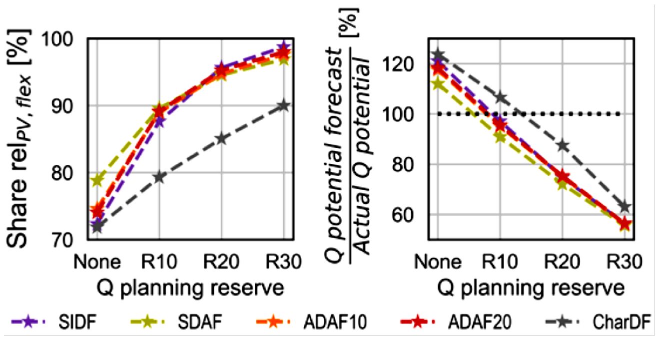


Figure 29: Share of reliable reactive potential forecast (left) and ratio of forecasted reactive power energy potential to actual reactive power energy potential (right) in daytime hours [30].

4 RESEARCH AND APPLICATION EXAMPLES WITH PV AND OTHER RENEWABLES

4.1 Application-oriented Reactive Power Management (Germany)

Authors: Haonan Wang, Abdullah Altayara, Denis Mende (Fraunhofer IEE)

Objective: control the reactive power exchange at the 110 kV-NCP using local reactive power provision from DERs at the MV level

Case study test region: smart grid region located in Southern Germany

Considered PV systems: 15 large PV systems (total: 10.7 MVA), 1450 small PV systems (total: 30.4 MVA)

PV inverter function: Q(V)

4.1.1 Motivation

Application oriented reactive power management approach allows DSOs to control the exchange of reactive power at the gird interfaces and support local voltage stability without requiring complex information and communication technology infrastructure [8]. Major factors are considered when designing this reactive power management concept as following:

- Allow the controlled exchange of reactive power at the connection point between different voltage levels.
- Adaptable with the existing local *Q(V)* control.
- Implementation with limited online information from the grid to compensate for the absence of online measurements.
- Stable and easy to incorporate into the current grid operation system.
- Applicable to other grids and at different voltage levels.

4.1.2 Method

The method aims to control the reactive power exchange at the 110 kV-NCP using local reactive power provision from DERs at the MV level. It only needs the actual reactive power exchange at the 110 kV-NCP as its online measurement for distribution management system (DMS), which makes it suitable for distribution systems, where only limited online information is available [8].

Control process (see Figure 30):

1. Determine the target value of reactive power exchange at 110 kV-NCP
2. Determine the current deviation of reactive power exchange at 110 kV-NCP
3. Determine the reactive power set-point deviation for all controllable MV-DER

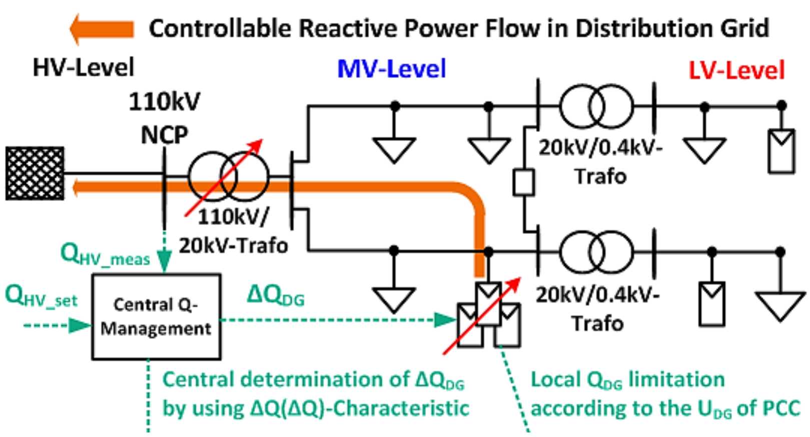


Figure 30: Proposed application-oriented reactive power management approach [8].

4. Send the reactive power set-point default to MV-DER-controller
5. Local limitation according to the extended *Q*(*V*)-characteristic
6. Set the reactive power provision of controllable MV-DERs

4.1.3 Selected case study area

A smart grid region located in Southern Germany is selected as a case study area (illustrated in Figure 31), which included voltage levels of MV, HV/MV and LV and has one connection point to the HV level. The region has 15 large PV systems connected to the medium voltage level at 12 grid connection points with a total installed capacity around 10.7 MVA, and approximately 1450 small PV units at the LV level with a total installed capacity of around 30.4 MVA.

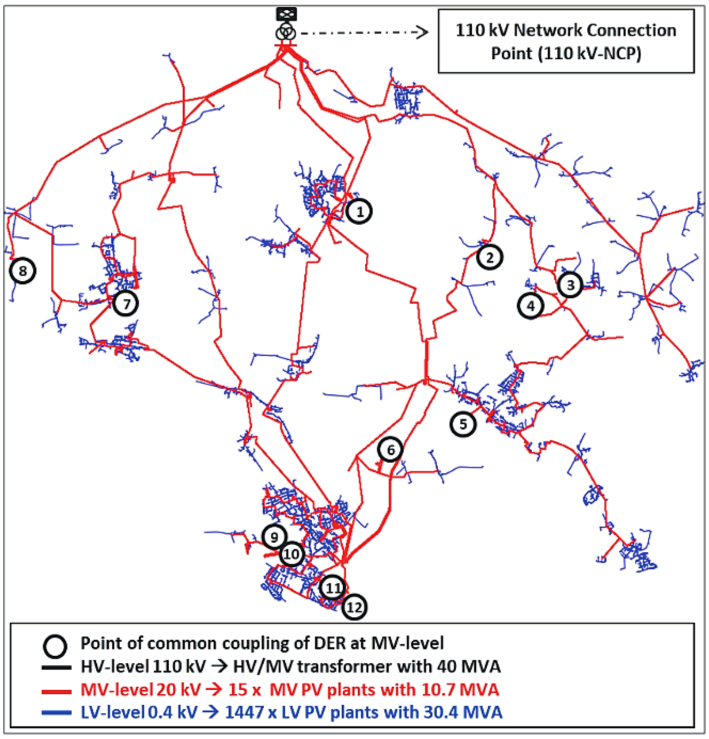


Figure 31: Developed multi-voltage grid model for the smart region Seebach [8].

4.1.4 Case studies

4.1.4.1 Minimization of reactive power exchange at 110 kV-NCP

Assumptions:

There should be no exchange of inductive or capacitive reactive power at the 110 kV network connection point (NCP). The set point for reactive power exchange at the 110 kV-NCP is therefore set to zero, so that the proposed reactive power management approach should fully compensate for any reactive power exchange at this point. Using the established simulation environment, daily simulations are then run for a selected sunny day and a cloudy day at a resolution of one minute.

Control objective:

Minimize the exchange of reactive power at the 110 kV-NCP by centrally controlling the DER at the MV level.

Results:

Figure 32 illustrates the fluctuation of reactive power exchange at 110 kV-NCP over the course of a sunny day (top). The blue line represents the original reactive power exchange without the use of reactive power management, while the red line shows the controlled reactive power exchange with reactive power management applied.

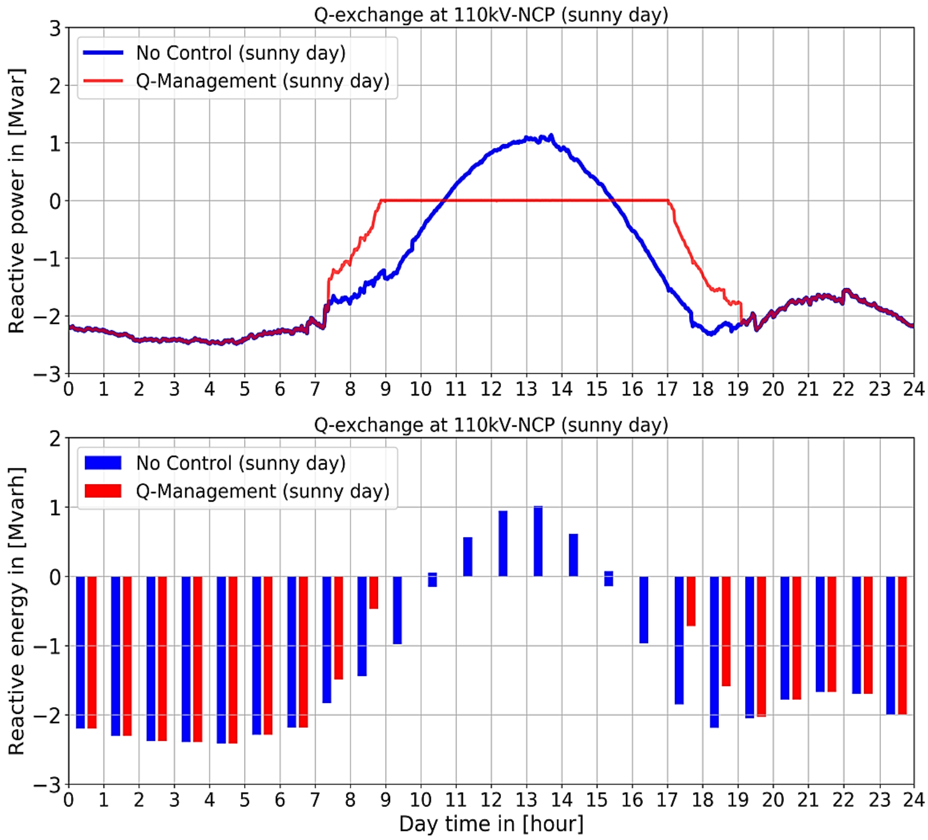


Figure 32: Reactive power exchange at 110 kV-NCP (top) and the reactive energy exchange at 110 kV-NCP (bottom) for the investigated sunny day [8].

Due to changes in PV generation, changes in the loading of grid components such as transformers and cables, and changes in the reactive power consumption of consumers, the reactive power exchange at the 110 kV-NCP varies continuously throughout the sunny day (blue line). The use of the reactive power management approach helps to significantly reduce the reactive power exchange (red line).

During times of high PV generation and high reactive power provision potential from PV (such as from hour 9:00 to 17:00), it is possible to see almost complete compensation of reactive power exchanges at 110 kV-NCP. This suggests that even though the relationship between reactive power provision from PV and the resulting reactive power changes at 110 kV-NCP is simplified in the proposed reactive power management concept, there is little deviation from the desired control in times of high PV feed-in. This indicates that the control accuracy is satisfactory for sunny days with low PV variability and low variability of the reactive power exchange at the high voltage/medium voltage interface.

In addition, Figure 32 (bottom) also displays the resulting reactive energy exchange at 110 kV-NCP (in Mvarh) over the course of the simulated sunny day. The blue bars represent the reactive energy exchange in the reference scenario without control, while the red bars show the reduced reactive energy using the proposed reactive power management concept. The proposed control approach has the potential to significantly reduce the exchanged reactive energy, particularly during times of high PV feed-in. For example, during the period between hours 9:00 and 17:00 on the sunny day in question, there is approximately 3.3 Mvarh of underexcited reactive power exchange and 2.2 Mvarh of overexcited reactive power exchange in the reference scenario without reactive power control, which is undesirable and should be fully compensated. With the proposed reactive power management, this compensation is achieved by using controllable PV systems at the medium voltage level, resulting in almost full compensation of the reactive power exchange at 110 kV-NCP. Over the entire simulated sunny day (hours 0:00 to 24:00), there is a total of 3.3 Mvarh of underexcited reactive power exchange and 34.9 Mvarh of overexcited reactive power exchange. The proposed reactive power management approach enables almost complete compensation of the underexcited reactive power exchange, but only about 15.2% of the total overexcited reactive energy exchange can be reduced, with around 29.6 Mvarh still needing to be compensated. As a result, the potential for energy savings is limited during times with no or low PV feed-in, when the selected grid section Seebach (which has a high cabling degree) typically has exceptionally low loading of grid components and therefore exhibits overexcited reactive power exchange at 110 kV-NCP.

4.1.4.2 Requested reactive power provision at 110 kV-NCP

Assumptions:

In case study 2, it is assumed that the high voltage grid operator may request different reactive power set points at the 110 kV-NCP. To meet these different set points, the reactive power exchange at the 110 kV-NCP of the medium voltage Seebach grid is controlled using the proposed reactive power management concept.

Control objective:

The ability to control the exchange of reactive power at the grid interface between two voltage levels is seen as a crucial ancillary service that can be provided by distribution system operators using the reactive power provision capabilities of distributed energy resources in their networks.

Results:

The results in Figure 33 show how the controlled exchange of reactive power at 110 kV-NCP responds to different set point requests from the high voltage grid operator. When there is sufficient reactive power available from controlled photovoltaic units, the requested setpoints can be met with minimal deviation from the control. However, when the requested set point is 2 Mvar (overexcited), it may not always be possible to meet the request due to limited overexcited reactive power availability from distributed energy resources and high voltages at the point of common coupling of the distributed energy resources.

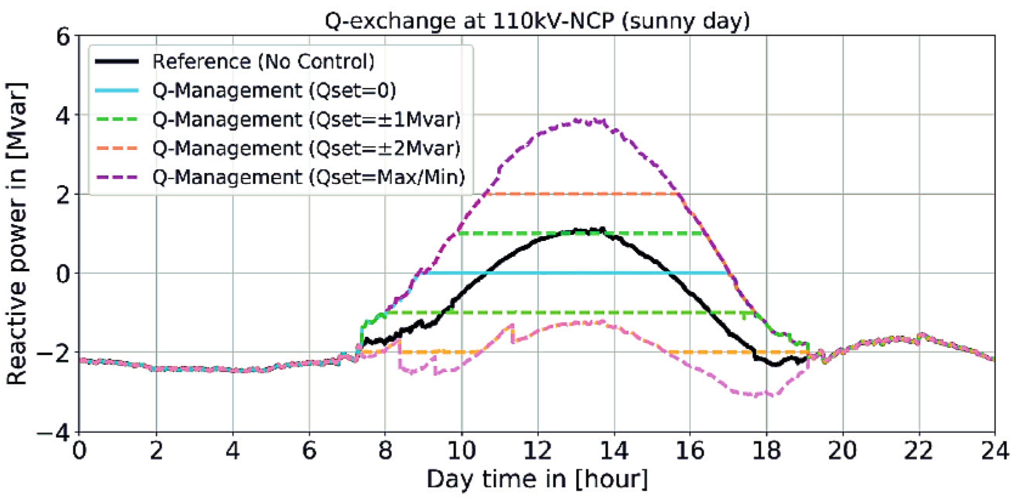


Figure 33: Reactive power exchanges at 110 kV-NCP with different reactive power setpoints [8].

By comparing the minimum and maximum exchange of reactive power, it can also be observed that at times of high photovoltaic feed-in (hour 13:00), there is a significant potential for reactive power provision at 110 kV-NCP, ranging from 1.2 Mvar (overexcited) to 4 Mvar (underexcited). The proposed reactive power management concept allows the medium voltage grid operator to provide any requested reactive power exchange at 110 kV-NCP within this range at hour 13:00.

4.1.4.3 Parallel operation with local voltage controls at LV level

Assumptions:

The study utilizes a time series simulation to examine a clear sky, sunny summer day using the Seebach multi-voltage-level grid model. A case study is conducted in the Seebach area, where 25% of the PV units at the LV level, representing 25% of the total installed PV capacity at the LV level, are randomly selected. The selected LV PV units are actively controlled using different local voltage control strategies such as fixed cos φ, $P(V)$, $Q(V)$. Additionally, a reactive power control approach is implemented for larger PV systems at the MV level.

Control objective:

The goal of the control is to minimize the reactive power exchange at the 110 kV-NCP to 0 Mvar.

Results:

Figure 34 illustrates the impact of the proposed reactive power management on the active and reactive power exchange at 110 kV-NCP for a clear sky summer day, taking into account different local voltage control strategies at the low voltage level with 25% of the low voltage photovoltaic systems actively controlled.

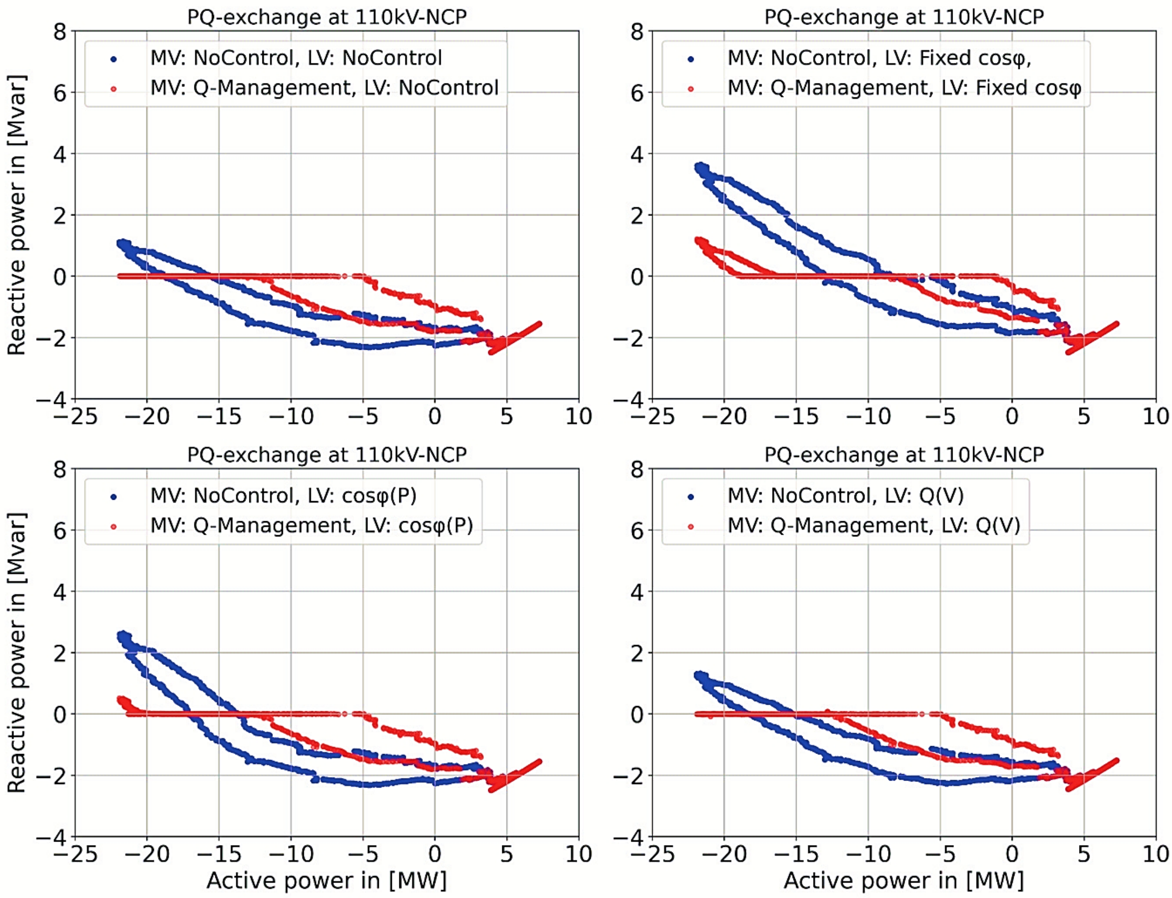


Figure 34: Active and reactive power exchange at 110 kV-NCP using proposed reactive management at MV level and different local voltage control strategies at LV level [8].

Applying both local voltage controls (fixed power factor and power factor proportional to power) to the low voltage photovoltaic systems significantly increases the underexcited reactive power exchange at the 110 kV-NCP (represented by the blue dots in Figure 9). In comparison, the local reactive power to voltage control has only a small effect on it. This aligns with previously mentioned results in [31]. By using the central reactive power management developed in this work, both the underexcited and overexcited reactive power exchange at the 110 kV-NCP can be significantly reduced in all four investigated scenarios (represented by the red dots in Figure 34). This effect is particularly evident in both scenarios with no control and reactive power to voltage control applied to low voltage photovoltaic units, in which full compensation of reactive power exchange at 110 kV-NCP can be observed during times of high photovoltaic feed-in and reverse power flow (−5 MW to −22 MW). In both scenarios with fixed power factor and power factor proportional to power applied to low voltage photovoltaic units, full reactive power compensation at 110 kV-NCP cannot always be achieved due to the significant impact of both local voltage control strategies. However, the proposed reactive power management concept still enables significant reactive power reduction at the grid interface, with about 2 Mvar reactive power reduction during times of maximum reverse power flow (−22 MW). With the so-called Q at Night functionality [32], some photovoltaic units can also provide reactive power during times without photovoltaic feed-in. With this additional functionality applied to medium voltage photovoltaic systems, a significant reduction in reactive power exchange at 110 kV-NCP should also be possible during times of little or no photovoltaic feed-in.

4.2 Methods and Scenarios for Strategic Grid Planning in Distribution Networks (Austria)

Authors: Helfried Brunner, Roman Schwalbe, Clemens Korner, Roland Bründlinger (All AIT – Austrian Institute of Technology)

Objective: Quantitative survey of the area effectiveness of future medium and long-term network related measures (network restructuring, operational strategies) in the entire medium- and low-voltage network infrastructure of the DSOs (network levels 5,6, and 7). This is done for various development scenarios of the consumption and feed-in behavior of network customers based on scientifically developed future scenarios and various network expansion measures.

Field test region: Supply regions of three Austrian DSOs

Considered PV systems: Yes

PV inverter function: Q(V)

4.2.1 Introduction

According to the regulatory framework, Austria is very much following European requirements, which have been implemented in Austrian standards and grid codes (see chapter 2.4). That means power electronic based grid interfaces, including PV inverters, are required to provide certain reactive power management functionalities. The utilization of these capabilities by Austrian grid operators by 2023 is in practice quite limited. Just a very small number of the > 120 Austrian distribution grid operators are considering $Q(V)$ as a measure to increase low voltage grid hosting capacity, in particular. The majority is still requesting cos φ = 1 setting in course of the grid integration of residential level PV. The higher the voltage level, the more reactive power management is already utilized.

4.2.2 Simulations and investigation

Together with three Austrian distribution grid operators a project has been performed to enable a quantitative survey of the area effectiveness of future medium and long-term network related measures (network restructuring, operational strategies) in the entire medium- and low-voltage network infrastructure of the DSOs. This is done for various development scenarios of the consumption and feed-in behavior of network customers based on scientifically developed future scenarios and various network expansion measures.

The approach consists of four steps. In a first step, generally applicable methods are defined to derive future scenarios using the defined technologies (ramp-up scenarios). In a second step, concepts for the spatial distribution of the technologies are developed and applied to the respective network areas (regionalization) [33–35]. In a third step, corresponding approaches for generating load profiles are applied. In the fourth and last step, corresponding power flow simulations are defined and carried out for the full MV and LV supply area.

The necessary input parameters can be roughly categorized into the sub-areas of future and rollout scenarios as well as infrastructure and operating modes.

Roll-out scenarios, based on the climate policy goals of the federal government are regionalized to the supply areas of the network operators [33–35]. Within the study PV, heat pumps and e-mobility have been considered. In addition to the regionalized/localized (georeferenced) roll-out scenarios, different operating strategies and functional concepts are defined and mapped in the form of simplified simulation models. These include different modes of operation (e.g., simultaneity factors in electromobility) and system functions such as reactive and active power control concepts (e.g., $Q(V)$, $P(V)$). All technology rollout scenarios are combined in an overall scenario.

The basic input parameter for the area-wide simulations is the entire existing network infrastructure of the respective network operator network levels. The methodology includes the preparation and the plausibility check of the existing and imported network data. Different network reinforcement mechanisms and technology options for avoiding voltage limit violations as well as overloading grid assets (see Figure 35) are considered. Models and algorithms representing them are included in the framework.

In the following the discussions and conclusion around the specific measure of reactive power control ($Q(V)$) in Austrian distribution grids are presented.

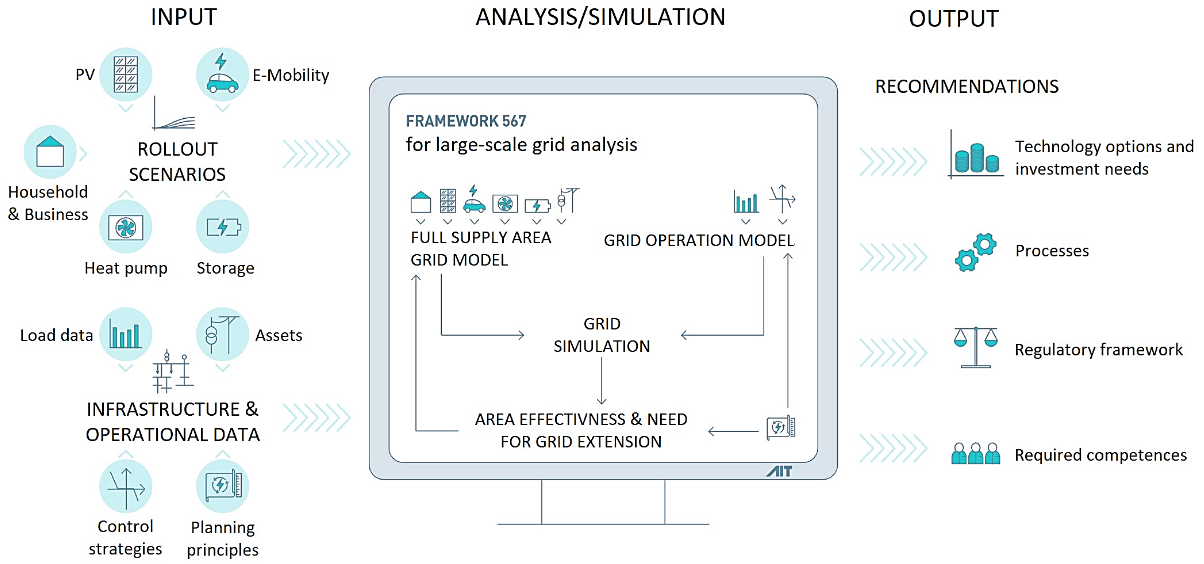


Figure 35: Methodology for large scale power system analysis.

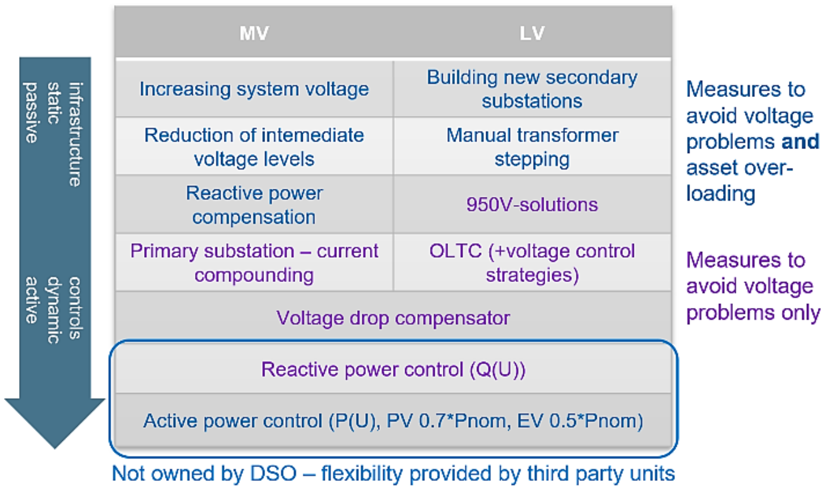


Figure 36: Technology options to avoid voltage limit violations and asset overloading.

4.2.3 Experiences, discussion and conclusions around Q(V) in Austrian low voltage grids

As mentioned above, $Q(V)$ is not yet widely utilized by Austrian grid operators. There are two main concerns related to $Q(V)$ control. The first one is, that this measure is not directly in hand of the DSOs, since it is behind the meter at costumer level. So, the flexibility is provided by third party units. There are concerns, that it may be exceedingly difficult to ensure and to monitor the continuous and reliable operation of the $Q(V)$ settings agreed upon during the grid connection procedure. The second reason is that Austrian grid infrastructure is very heterogenous both in terms of topologies as well as in term of assets, even within one DSO. That means different voltage levels (e.g. 10, 20, 30 kV at MV level), different shares of cables and overhead lines with different diameters (finally R/X ratios) can be found, which have strong influence on the effect of $Q(V)$ control on voltage band management as well as on the overall reactive energy demand for $Q(V)$ control at lower voltage levels.

The investigation presented above proofed the argument related to the heterogenous character of the grids even within supply areas of one DSO, resulting in the requirement of a differentiated as well as detailed analysis of the actual contribution of $Q(V)$ control. This includes the additional reactive energy demand due to $Q(V)$ control. The additional reactive power flow leads to overloading of a reasonable share of secondary substation transformers

(MV/LV). This results in a requested replacement of transformers when enabling large scale *Q*(*V*) control in presence of a high share of PV in certain low voltage areas. In addition, the increased amount of reactive energy needs to be provided or purchased by the DSO. Both effects are going to reduce the economic benefit of implementing *Q*(*V*) control.

Discussion related to the reduction of reactive energy demand showed that in future it might be an option to combine *Q*(*V*) control at low voltage level with PV curtailments (e.g., 70% of installed capacity) as well as with primary substation (HV/MV) current compounding to reduce the resulting reactive energy demand.

Currently, more and more DSOs in Austria are considering *Q*(*V*) as an option for the future. Due to the heterogeneous grid structures, analysis of the entire supply areas is beneficial. For the time being grid operators in Austria do not have the capability of performing large-scale grid simulations of the entire supply area, including different future scenarios, in their own simulation environments. This is a barrier for investigating the real value of reactive power management in distribution grids.

4.3 Evaluation of the voltage control performance in distribution system (Japan)

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Contributors: TEPCO Power Grid. Incorporated, Tokyo Electric Power Company Holdings, Inc., Waseda University

Objective: evaluation of the voltage control performance between fixed power factor and updating power factor setting etc.

Field test region: Simulation based on the actual distribution system in Tokyo area

Considered PV systems: 25.4 MW in 2020 and 30.2 MW in 2040

PV inverter function: Q(V) control

4.3.1 Introduction

As fixed power factor control mentioned in the previous chapter, if a DER connects into a distribution system, the power factor value is typically 0.9 lagging or 0.95 lagging. However, as the number of PVs and other resources increases, it may become difficult to maintain proper voltage with the current voltage control based on fixed power factor.

Therefore, a project conducted to evaluate the voltage control performance between fixed power factor and updating power factor setting etc. in terms of the hosting capacity considering PV penetration scenario from 2025 to 2040, which was mainly conducted by a consortium of TEPCO Power Grid. Incorporated, Tokyo Electric Power Company Holdings, Inc. and Waseda University, supported by NEDO.

4.3.2 Simulation environment

The suitable power factor setting for clearing voltage violation may change depending on the characteristics of network topology such as line length, and condition of DER penetration. To evaluate the voltage control performance, the detailed distribution system model is required for simulation.

Therefore, in addition to verification by numerical simulation, evaluation of voltage control by current countermeasures was carried out in the hardware testbed (ANSWER: Active Network System with Energy Resources) owned by Waseda University. The main object of evaluation was the behavior of PV-PCS during line switching, which is difficult to evaluate by numerical simulation, and the evaluation of the effect on the system voltage. For the evaluation, ANSWER was expanded such as by introducing a line switching device. Figure 37 shows an overview of the ANSWER. It reproduces the flow of electricity from a 6.6 kV medium-voltage distribution system to a 100 V low-voltage consumer by scaling it down to 400 V/100 V and simulates the effect of PV penetration on the distribution system voltage using a circuit model.

The distribution system models are constructed based on the actual distribution system in Tokyo area, Japan. The total length of medium-voltage distribution line in each feeder is from 5.2 km to 9.8 km and the feeder's types are residential and industrial. The selected model is a severe model in terms of voltage control, because the line length

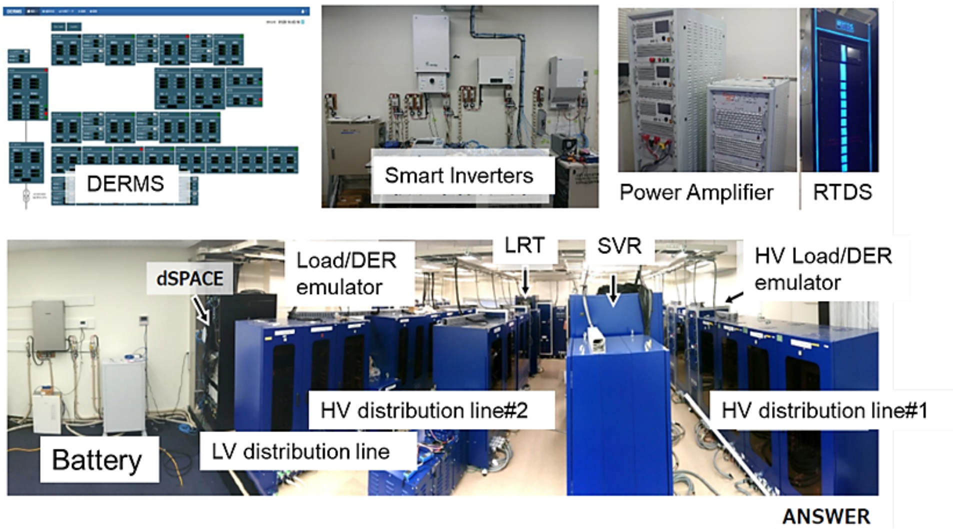

Figure 37: Overall of the hardware testbed.

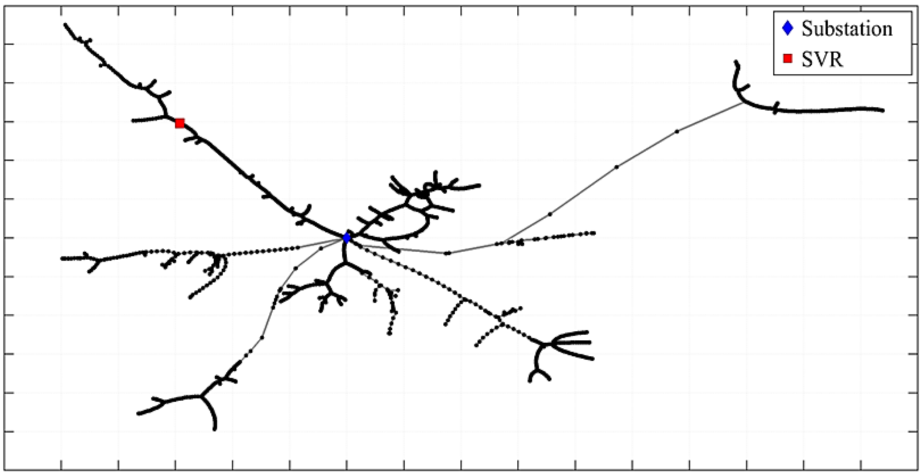

Figure 38: Bank model with feeders in a low-voltage distribution system.

is longer than other systems, while a standard distribution line is 2km to 8km, and the amount of PV installation is larger in 2020. The model has seven feeders including the medium- and low-voltage classes in a distribution system.

The total load capacity is 15.1 MW. Voltage control devices are OLTC and one SVR. The tap operations of OLTC and SVR are performed Z-characteristics and vector LDC (Line Drop Compensation) control, respectively. In the simulation, at first, the voltage control performance of default power factor setting is evaluated based on hosting capacity. The default power factor setting means what the power factor value in medium-voltage and low-voltage PV are 0.90 and 0.95 lagging respectively. If the voltage violation occurs, the power factor setting is adjusted to clear voltage violation. The judgement of voltage violation is based on the voltage in low-voltage customers and the voltage is 10 minutes moving average value. The acceptable range is from 95 V to 107 V based on the Japanese act or rules.

4.3.3 Scenario definition

A PV penetration scenario is constructed from 2025 to 2040 shown as Figure 25. It is created in five-year increments, adopting the minimum value among the 2020 actual results or the Japan's Long-Term Energy Demand and Supply Outlook, the International Energy Agency (IEA) World Energy Outlook 2020, and the PV Outlook 2050 assumed by the Japan Photovoltaic Energy Association (JPEA). The scenario shown here assumes 64 GW in 2030, 125 GW in 2040, and 200 GW in 2050. Incidentally, an evaluation is conducted separately using the amount of hosting capacity equivalent to the assumed amount of it in 2030 (87.6 GW in the minimum case and 117.6 GW in the maximum case), as indicated subsequently in the Japan's Sixth Strategic Energy Plan.

Moreover, the voltage class is allocated by DSO's area, with 48% low voltage distribution systems, 34% medium-voltage distribution systems, and 18% transmission systems, based on the assumption that the current ratio of PV installation by voltage class will continue.

Furthermore, to estimate the hosting PV capacity in the bank model, a Monte Carlo simulation is conducted to randomly distribute the PV hosting capacity by voltage classes and all distribution lines DSOs, and then adds to the cumulative PV hosting capacity for each distribution line.

In this bunk model, the amount of PV capacity is 25.4 MW in 2020 and 30.2 MW in 2040. The verification days are 4 days in each year. The 4 days are the combination of load type (heavy and light) and PV type (sunny and cloudy).

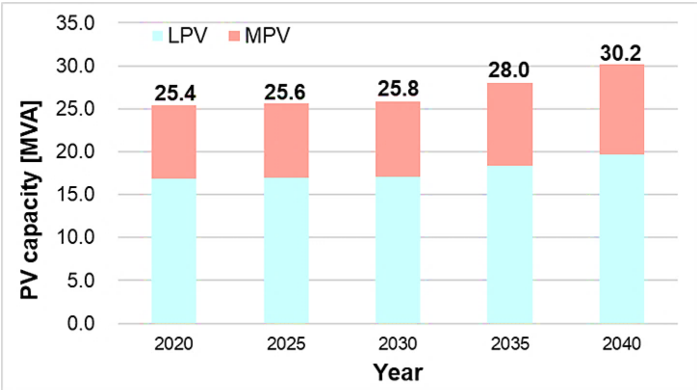

Figure 39: PV penetration scenario.

4.3.4 *Evaluation result*

According to the simulation results, the voltage violation did not occur by 2035 under the default power factor settings. However, in 2040 PV penetration condition, the voltage violation occurred on the heavy load and cloudy PV day under the default setting (see Figure 40).

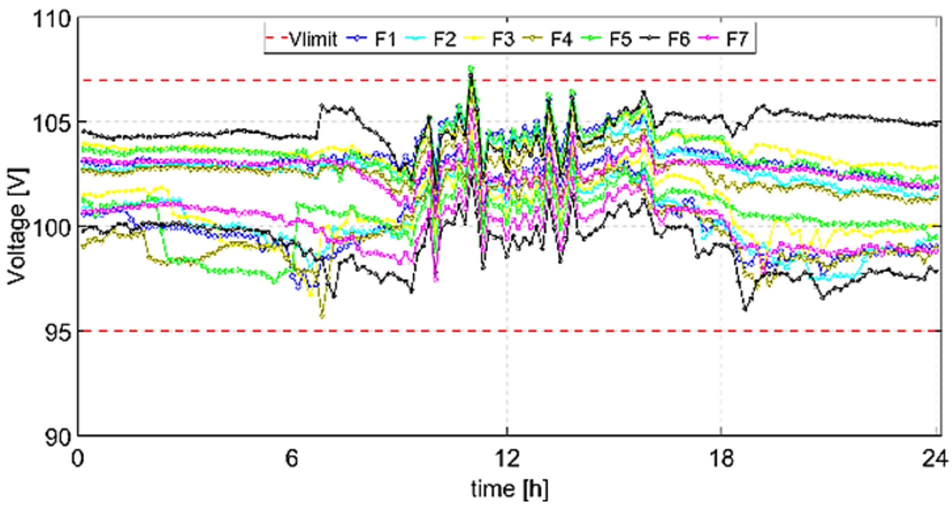

Figure 40: Example of voltage profile in 2040 - Default power factor setting (MPF/LPF=90/95).

The voltage fluctuation by PV generation caused the voltage violation during daytime. Thus, the voltage control performance of the default power factor setting was high, but DSO needs to update the power factor settings to increase PV penetration without voltage violation. In 2040 PV penetration setting, the power factor settings of medium voltage are adjusted from 0.90 based on the voltage condition in each feeder. Then, the voltage violation was cleared on the heavy load and cloudy PV day (see Figure 41).

Updating the power factor setting seems to be a useful scheme, because DSO does not be required the new equipment. From the results, the voltage control performance by default power factor setting was high, however, the performance could be improved more by updating the power factor setting based on the voltage condition in each feeder. Based on this result etc., "the power factor setting value must be changed according to the request of DSOs, with a function that allows it to be changed" was stipulated in the new grid code published in 2023.

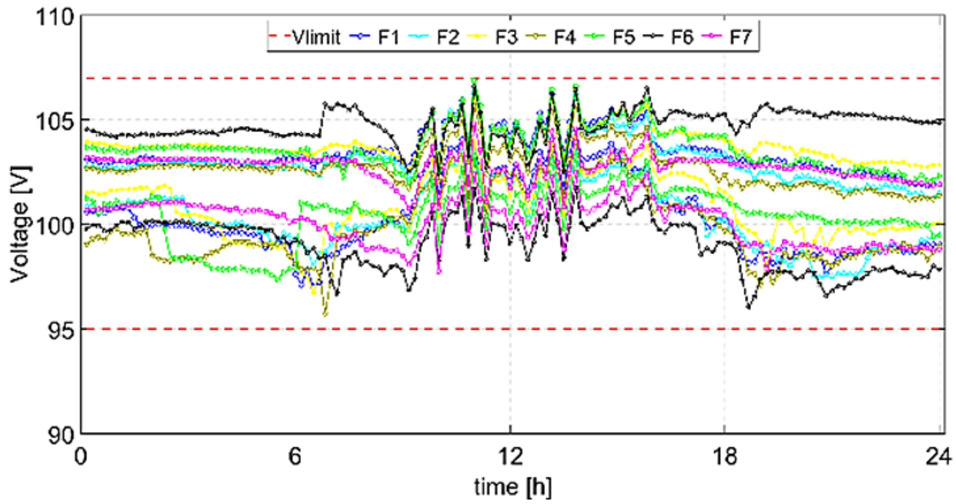

Figure 41: Example of voltage profile in 2040 - Updated power factor setting (MPF/LPF=92/95).

Furthermore, in this NEDO project, based on the questionnaire to DSOs, other control methods are also evaluated as considered measures including setting power factor on schedules by time of day or deciding the set power factor depending on the active power output autonomously, as well as conducted an R&D for the voltage control method using reinforcement learning as a countermeasure in the quite distant future.

5 SUMMARY AND RECOMMENDATIONS

This report provides an overview of reactive power management within the context of decentralized renewable energy sources. Across several countries, distinct regulatory approaches and exemplary strategies have been observed to address the intricate challenges posed by the integration of DER, including PV and other renewables. Germany, for instance, emphasizes the provision of controllable reactive power by connected DER, underlining the significance of adhering to fixed grid codes. Switzerland, on the other hand, focuses on equitable compensation for DSOs contributing reactive power to the grid, highlighting the importance of regulatory compliance. In Japan, a fixed power factor control strategy is adopted. Italy's approach, particularly for generators directly connected to the transmission grid, emphasizes continuous reactive power regulation as per capability curves, further underscoring the complexity of grid management.

To ensure the resilience and efficiency of power systems, there is a call for prompt updates to regulatory frameworks. Due to even faster changes in local environments, which is especially true for reactive power flexibilities and management.

Subsequently, the report focuses on the reactive power support provided by DERs in the context of the German power system, particularly with the increasing penetration of renewable energy sources. A case study explores the use of a time series model to analyze the reactive power support potential of DERs in a distribution network. Key performance indicators, including Reactive Flexibility Hours (RFH), Reactive Capacity Credit (RCC), and Reactive Energy Credit (REC), are defined to assess the capability of DERs to provide reactive power support. The study considers different DER types, such as Hydro, Thermal, and PV DERs, with a focus on their reactive power capabilities and contributions to the grid. The report also delves into a case study that forecasts the reactive power flexibility potential of a large PV plant in a specific section of the German grid. Furthermore, a discussion of the assessment of PV reactive power forecast errors and an introduction of a reliability indicator to evaluate the accuracy of reactive power flexibility forecasts is highlighted. The reliability analysis considers the prevention of overestimation in forecasted reactive power flexibility potential compared to observed values. The results indicate the need for high reliability in forecasting DER reactive power flexibility, with considerations for planning reserves to enhance forecast accuracy. Following by a case study Switzerland that shows the technical and regulatory aspects of coordinating reactive power between TSOs and DSOs, emphasizing the importance of adhering to national and international regulations to ensure a reliable grid.

Moving on to research and application examples, the German case study on application-oriented reactive power management highlights its effectiveness in minimizing reactive power exchange at the 110 kV-NCP. Leveraging local reactive power from MV-DERs, the approach proves adaptable, stable, and seamlessly integrates into existing grid operations. The simulations demonstrate notable reductions in reactive power exchange, showcasing its potential for enhancing grid stability, especially during high PV feed-in periods. The study emphasizes the approach's flexibility in responding to varying set point requests, though challenges arise in certain conditions. Overall, this application-oriented strategy emerges as a promising solution for optimizing grid performance and justifies further exploration in diverse grid scenarios.

The second research example underscores the limited utilization of reactive power control (Q(V)) in Austrian low voltage grids, primarily due to concerns about third-party control and the diverse and heterogeneous nature of the country's grid infrastructure. The simulations and investigations reveal challenges such as transformer overloading and increased reactive energy demand, potentially diminishing the economic benefits of widespread Q(V) implementation. Despite growing recognition, the lack of comprehensive simulation capabilities among Austrian Distribution System Operators (DSOs) remains a notable barrier, emphasizing the need for enhanced tools to evaluate the true value of reactive power management in the evolving Austrian distribution grids.

In Japan, the case study discussed the evolving power factor control strategy and the need to update power factor settings as PV penetration increases. Research findings underscored the importance of dynamic power factor adjustments to accommodate higher PV capacities without compromising grid stability.

A need is arising for advancing reactive power management in the evolving energy landscape. This includes the imperative need for further research, prompt updates to regulatory frameworks, strengthened collaboration between TSOs and DSOs, and a focus on developing accurate methods for forecasting reactive power from renewable sources.

In conclusion, several needs for advancing reactive power management within the energy transition landscape can be highlighted. There is an imperative need for further research in the field of reactive power management, especially as renewable energy penetration continues to rise. To ensure the resilience and efficiency of power systems, regulatory frameworks governing reactive power management must be promptly updated to align with the evolving energy landscape. Collaboration between TSOs and DSOs should be strengthened to facilitate more effective reactive power management. Additionally, research efforts should focus on developing more accurate and reliable methods for forecasting reactive power output from renewable energy sources, as well as the creation of novel control and optimization algorithms tailored for reactive power management. Exploring the potential of DERs to provide reactive power services is essential, and the integration of Information and Communication Technologies (ICT) should be employed to enhance coordination between TSOs and DSOs in managing reactive power.

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ISBN 978-3-907281-51-2