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International Good Practices in Renewable Distributed Generation

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1 Introduction

The energy transition is sparking a multitude of changes in the energy sector across many dimensions. One such change is the decentralisation of power generation, made possible by the availability of low-cost, small-scale renewable energy technologies. Unlike decades ago, when power generation was predominantly centralised, we are witnessing the gradual integration of numerous small-scale installations into the power system, primarily connected to distribution grids. As opportunities to scale up distributed generation at the residential, commercial, and industrial level become attractive in many countries and regions of the world, this shift brings forth a range of implications for the power system, necessitating a deeper understanding of the potential benefits and challenges of widespread distributed generation.

This GET.transform Brief aims to provide an overview of what distributed generation is, what key technical implications are commonly observed in the system, and what measures are available to address and help avoid these issues. The content of this Brief is particularly valuable for energy sector decision-makers, utilities, and electricity system operators. It covers measures relevant for electricity network planning and operation and offers a broad overview of main regulatory and administrative aspects, including requirements and standards pertaining to distributed generation.

Effective preparation and communication are identified as prerequisites for the successful roll-out of distributed generation. Given the mix of technical, regulatory and administrative aspects that need to be addressed, defining a robust framework for a smooth integration of distributed generation demands concerted action among different decision makers of the energy sector in a country. Furthermore, taking early action to prepare the conditions for distributed generation integration can identify low-cost solutions and avoid more costly measures in the future.

We sincerely hope that you, as the reader, find this Brief informative and useful in navigating the complexities of distributed generation. For those seeking further information on specific topics, additional sources are included for further reading in the last section of this Brief.

To learn more about GET.transform activities related to distributed generation and other captivating topics of the energy transformation, please visit get-transform.eu.

2 What is Distributed Generation and What Is this Brief About?

Several definitions have been used to describe distributed generation (DG) and it is common for each country or region to have its own. Aspects that have been considered when defining DG include purpose, location, size of installation, power delivery area, technology, environmental impact, mode of operation, ownership and probably a few more.

WHAT IS DISTRIBUTED GENERATION?

'In general, distributed generation (DG) can be defined as electric power generation within distribution networks, or on the customer-side of the network' (Ackermann, Andersson, & Söder, 2000).

For this report, however, the definition given in Ackermann et al. (2000) is taken as a reference, making **purpose** and **location** the relevant characteristics of a generation system when defining DG, as they conclude that all other aspects cannot clearly confine all possible cases of DG. For example, countries often have different definitions for the size of DG (ranging from a few kW to tens of MW of power capacity), or do not include all types of technologies (e.g., solar PV, wind, small hydro, biomass, as well as fossil fuel-based DG). However, most countries have a coherent definition of transmission and distribution networks, providing a clear distinction between DG and other generation that is connected to the transmission network. For the context of this brief, we therefore talk about DG when:

- The **purpose** of DG is to provide a source of power generation, for self-supply and/or export to the power grid.
- The **location** of DG is defined as the installation and operation of electric power generation units connected directly to the distribution network, or connected to the network on the customer-side of the meter (i.e., behind the meter).The integration of renewable-based DG is the key focus of this brief, which aims at sharing lessons learned and state-of-the-art practices based on international experience, especially in countries that have experienced a significant DG penetration in recent years.

The following sections present key technical, interconnection and regulatory measures that should be considered to enable a smooth integration of renewable-based DG with high modularity and widespread installation in the distribution grid, such as PV and wind power plants.

The next section starts with an overview of the key technical impacts and considerations of DG penetration, and it is important to note that these are relevant for any DG technology, whether renewable- (e.g., PV, wind, biomass), or fossil-based (e.g., diesel or gas generators). However, special considerations apply for the integration of renewable-based DG, partly given by the modularity of technologies, especially for small-scale DG, which means there can be large numbers of installations spread across the grid, leading to more cases where the effects of DG can be observed. This is equally relevant for other distributed energy resources, such as electric vehicles (EVs), although this is beyond the scope of this discussion.

3 Technical Impacts and Measures

3.1 Technical Considerations of DG in the Operation of Distribution Systems

Traditionally, distribution grids have been designed to transfer power from the transmission system towards loads. With the introduction of DG, however, power is generated locally, close to consumption, which can have various effects and, at times, power may even be transferred from the distribution grid to the transmission grid, resulting in reverse power flows: this means that previous planning and operation practices for distribution grids that had worked before, including **voltage control, sizing of electrical assets** and design of **protection systems,** have to be updated if DG reaches high penetration levels – otherwise, during high DG in-feed and low demand, the following may occur:

— Overvoltages on electrical assets, e.g., voltage above the maximum regulated limit (commonly 90-110% of nominal voltage).
— Overloading of electrical assets (e.g., transformers and lines).
— Protection issues, such as the correct detection and clearance of short circuits.

The remainder of this section explains the technical implications of DG in more detail and shows readily available measures that can be put in place to enable DG integration. Although some of these implications require additional measures to adapt the old system to the new task, the good news is that, for low to medium DG penetration levels, DG integration can generally be implemented without major costs.

Now, elaborating further on the implications of overvoltage. Without DG in the system, **voltage** will always drop along a distribution system feeder. With the introduction of DG, a feeder with a load greater than the DG in-feed at a given time of day will still have a voltage drop; however, at times when DG in-feed is greater than the load, the feeder will experience a voltage rise, which can lead to **overvoltage,** due to a violation of the upper threshold of the regulated limits (i.e. 90-110%) as shown in **FIGURE 1**.

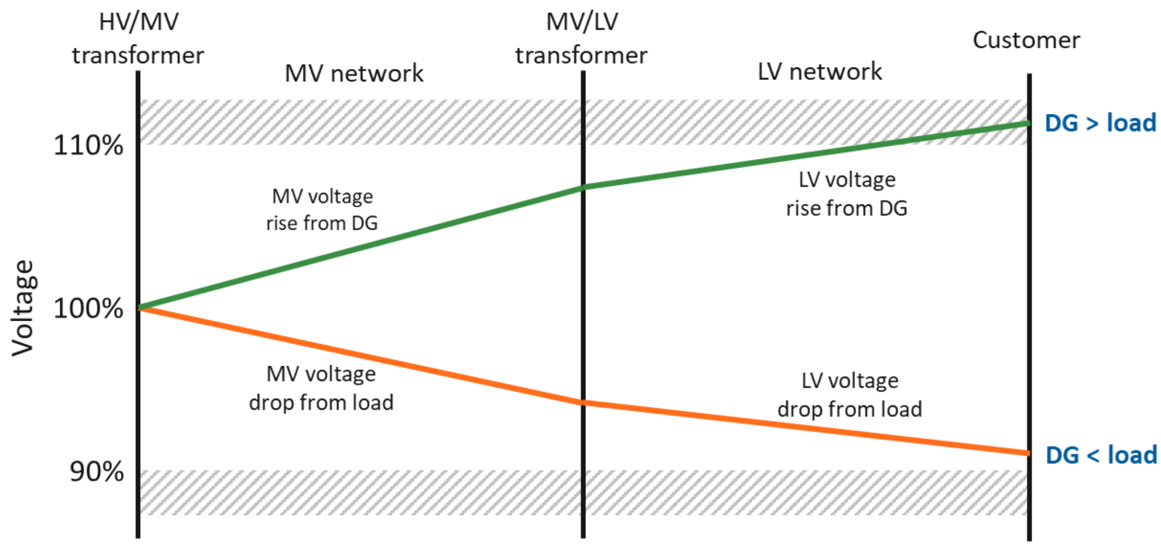

FIGURE 1. Voltage profile on a distribution feeder during times of high DG output exceeding load (green top line) and, during high load with little or no DG (orange), violating regulated limits of 90-110% (Energynautics 2014)

Asset **overloading** can also be a challenge if the DG power output surpasses previous load assumptions in specific areas of the network. This is especially true in rural areas, where there is sufficient space available to develop DG, while dwellings are often small: this may therefore render existing transformers and lines inadequate to handle the full power in-feed in specific areas of the grid during low load situations (NREL, 2016).

Additionally, **protection systems** (including fuses, relays, etc.) may need to account for DG fault currents during a short-circuit. High amounts of DG can influence the level and direction of fault current as the sources of fault current change from a typical top-down scenario to a multi-source scenario. This makes protection coordination more complex. However, inverter-based generators, such as PV and most wind power plants, contribute less fault current compared to synchronous DG (e.g., diesel generators). Therefore, in the case of PV and wind power, this technical impact is less critical compared to overvoltage and overloading issues. Some examples are given below:

— Relays and fuses located in the distribution network may experience higher fault currents, potentially higher than the interruption rating (**FIGURE 2** left).
— DG located 'behind' the short-circuit location can reduce the fault current contribution from the substation, masking the fault and thus requiring lower trip thresholds than before (**FIGURE 2** right).
— So-called 'sympathetic tripping' can lead to the tripping of a healthy feeder, if fault current direction is not evaluated[1], and the combined DG fault current exceeds the tripping threshold of the feeder.

Increased fault currents **Reduced fault currents**

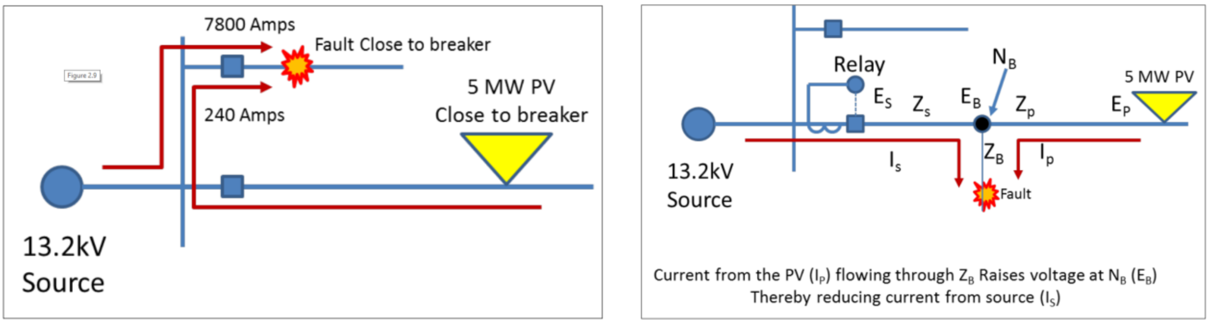

FIGURE 2. Examples of New Protection Considerations (NREL 2016)

[1] Both the value and the direction of the fault current may be relevant for distribution systems with DG. Direction is not always evaluated but, in specific cases, it could be considered since it could help to solve the issue of sympathetic tripping. This would require the installation of advanced protection equipment capable of reading fault current direction.

On the upside, networks suffering from severe undervoltage or overloading, may actually **benefit** from DG installations. The positive impact depends on the coincidence between DG production and peak load. If a good alignment is in place, or is enabled through the use of battery storage, distribution network investments can be postponed or avoided altogether.

In addition to the above impacts, **electric power losses** in the distribution system can be influenced by DG. Losses are reduced when energy is consumed close to generation. However, the reduction of losses by DG is not a general rule, but depends on the ratio and coincidence of generation and load that are close to each other.

3.2 Mitigation Measures

Several options exist to reduce the negative impacts that DG can create on the distribution system. Most of them aim to minimise the voltage rise in the network, while some also address loading issues. **TABLE 1** provides a comprehensive list of solutions for medium voltage (MV) and low voltage (LV) networks, ranked by their technical effectiveness in resolving the technical impacts of DG and increasing DG penetration levels. Other studies also examined the cost-effectiveness of solutions, such as those conducted in Australia (Nacmanson & Ochoa, 2021).

TABLE 1. Assessment of mitigation solutions from the EU project PVGRID (adapted from PVGRID 2013)

TECHNICAL EFFECTIVENESS OF SOLUTIONS	TECHNICAL SOLUTION
HIGH EFFECTIVENESS	Limiting maximum power in-feed
	Network reinforcement
	Reactive power control by DG inverter Q(V) and Q(P)
	Active power control by DG inverter P(V)
	Behind-the-metre battery storage
	On-Load Tap Changer for MV/LV transformer
MEDIUM EFFECTIVENESS	SCADA + direct load control
	Network reconfiguration
	Self-consumption by tariff incentives
	Wide area voltage control
	Static VAR control
	Booster transformer
	SCADA + DG inverter control (Q and P)
	DSO storage
LOW EFFECTIVENESS	Demand response through local price signals
	Active power flow-dependent voltage control
	Demand response through market price signals
	Advanced closed-loop operation

Note: DSO = Distributed System Operator; P = active power; Q = reactive power; SCADA = Supervisory Control and Data Acquisition; V = voltage; VAR = Volt-Amperes Reactive

Some of the most cost-effective and promising solutions are described in more detail below.

Voltage control by On-Load Tap Changing (OLTC) transformers. OLTC transformers provide the last point of voltage control in the distribution grid, being typically located at the interface between high and medium voltage grids. Options are available to enhance the OLTC voltage control capability to effectively utilise the full range of the allowed voltage in the MV and LV networks, such as:

> **Active power flow-dependent voltage control** measures the power flow across the transformer, setting a high voltage setpoint when power flows towards the distribution grid, and a low voltage setpoint when power flows back to the upstream network (i.e., reverse power flow), thus making better use of the regulated 90-110% voltage range.
>
> **Wide-area voltage control** systems use voltage measurements from different points in the grid as input to the voltage control of the OLTC transformer, which will aim for a set point that allows all points included in the control scheme to operate within the allowed voltage range. Due to high costs for monitoring and communication, this technology is typically only suitable for the MV network.
>
> **Use of OLTC transformers at LV level**, such as those located at the interface between medium and low voltage grids, as is done by German and Californian distribution grid operators in some grids with high PV penetration. The control algorithm can be implemented in several ways, e.g., by controlling the transformer's LV voltage close to its nominal value, by controlling a specific node in the LV network (similar to wide area voltage control), or by measuring the current flow direction and adjusting the tap accordingly (NREL, 2016).

Reactive power control by inverters. Reactive power control requires the apparent power of the inverter to be higher than the rated active power, slightly increasing the cost of the inverter. Otherwise, reactive power could not be used when it is most needed, i.e., during high active power production; otherwise, a power priority scheme would have to be added. Some solutions to reduce the voltage rise at the point of connection, caused by the DG's active power injection, include the use of some inverter settings, such as (based on EPRI (2018)):

> **Off-unity, under-excited power factor**, thereby lowering the voltage. However, the reactive currents will slightly increase line and transformer loading as well as electric losses.
>
> **Q(P) characteristic**, a better approach compared to the previous one, as it can be freely defined to associate reactive power with corresponding active power.
>
> **Q(V) characteristic**, allowing the unit to actively control the voltage at the connection point. Compared to the Q(P) characteristic, this has the advantage that reactive power is only consumed – and asset loading increased – if the voltage rises, whereas it is not activated in non-critical cases.

Limiting maximum power in-feed. For some DG technologies, such as PV, the actual peak power is usually reached only a few times a year. The peak power, however, determines the impact on the grid and the severity of reverse power flows. If the requirement is set that the grid must absorb the full injected peak power, the impact of DG will be overestimated for much of the year. Especially for small PV systems, the peak power output can usually be **capped to 70-80%** (through appropriate inverter sizing or specifications in the inverter settings), resulting in relatively low annual losses of 2-5% of annual energy production (Fraunhofer ISE, 2020). In most countries, 3% of annual losses is an acceptable value for renewable curtailment and/or capping. A more advanced measure could consider dynamic curtailment, which would entail having communication capability between the DG installation and the system operator. In Germany, this applies to larger installations (i.e., not applicable to solar home systems), where a curtailment of up to 3% of annual generation is allowed even if compensation is required.

Behind-the-meter battery storage. If the correlation between peak demand and DG peak generation is low and reflected in the electricity price or self-consumption benefits, there is a use case for energy storage, especially for PV, to store excess energy generated during the day for peak demand. The battery storage market is evolving rapidly, and **energy storage installed directly at, or in close proximity to, the DG installation** (termed behind-the-metre battery storage) may become a viable solution to minimise the grid impact of DG, along with other services it can provide to the system (IRENA, 2020). To observe a positive impact on reverse power flows, batteries must operate in **DG generation peak shaving mode**, where the battery is charged in a way that reduces the peak power output. Usually, the grid operator (or utility) will have to establish some incentive or price signal for DG plant owners to implement this mode of operation. However, until recently, the global distribution upgrade deferral through storage has been rather low (IRENA, 2017).

Network reinforcement. This is the simplest and most effective, but also often the **most expensive** solution to increase DG penetration in the distribution network. This solution helps alleviate both voltage and overloading issues. This is discussed further and put into perspective in section 4.3.

3.3 Distribution System Studies and Hosting Capacity Assessments

To facilitate the integration of DG into a distribution network, it is useful to study the current **hosting capacity** of the system, estimate the **future penetration of DG** and prepare the distribution grid accordingly. A **distribution system study** can help make informed decisions concerning **maximum DG hosting capacities**, selection of **mitigation measures**, and **investment** and **regulatory** requirements. These studies are carried out with DG hosting capacity simulation tools, including those implemented in commercial power system analysis software (e.g., DIgSILENT PowerFactory or ETAP). Such studies should be carried out for the specific conditions in a country, considering regulatory and planning principles, as well as the specific characteristics of the system to be investigated.

There are different methods to conduct distribution system studies. One example is the recent Australian study **focusing on LV** networks (ENEA Consulting, Citipower, Powercor Australia, 2020). The workflow used in this study is shown in **FIGURE 3**. The study classifies the **distribution grid into representative networks**, as a complete modelling of the distribution system is often infeasible. Models are built for each category and the DG is increased until technical limits are reached. Different mitigation options are applied, and the results compared to find the **most effective solution in terms of technical and financial feasibility for each network category**.

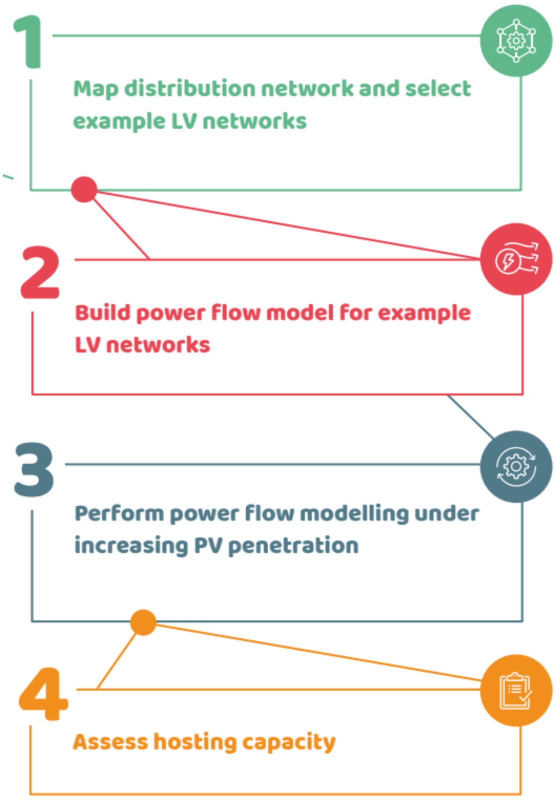

FIGURE 3. Workflow of the Australian Distribution Grid Study (ENEA Consulting, Citipower, Powercor Australia 2020)

Another study looking into **effects and mitigation options at HV and MV level** is the 'Distribution System Study, Rhineland-Palatinate' (Energynautics, Öko-Institut, Bird&Bird, 2014). A simplified version of the European transmission system was included in the study. Selected **reference networks** were used for the MV level and **generic networks** for rural, village and suburb categories for the LV level. The study also takes the approach of **assessing several mitigation measures**, including network expansion, dynamic line rating, high-temperature conductors, OLTC (with and without wide area voltage control), storage, power-to-heat, demand-side management, and curtailment.

4 Interconnection & Regulatory Considerations

The following sections set out key considerations for distributed generation that regulators should evaluate with increasing shares of DG in their respective countries. Many of the depicted shortcomings are still prevalent in many power systems and countries can benefit from the experiences and lessons learned from other systems.

4.1 Grid Codes for Distributed Generation

Grid codes are an essential mechanism to **define and standardise** the behaviour of DG installations and **enforce operational requirements** due to the potentially large number of distributed generators, which can amount to millions in a power system, especially with PV. When the number of DG installations is still low, this is not an issue, as standards like IEEE 1547-2003 (which has been adopted by many countries) from the Institute of Electrical and Electronics Engineers have already defined important DG performance for power quality, harmonics, and anti-islanding protection. However, DG development can quickly outpace grid code updates, which has led to expensive retrofits in multiple countries. For example, Germany had to update **frequency requirements** of more than 300,000 inverters at a cost exceeding EUR 170 million to combat the so-called '50.2 Hz issue', where many small-scale PV plants would disconnect during a larger frequency deviation (IRENA, 2016). Similar experiences occurred in Spain and the USA with **frequency and voltage ride-through requirements** (see examples in **FIGURE 4** and **FIGURE 5**). Good practices for grid code requirements should therefore be implemented as early as possible, including the adoption of new operational practices and standards (such as those outlined in the most recent IEEE 1547-2018 standard).

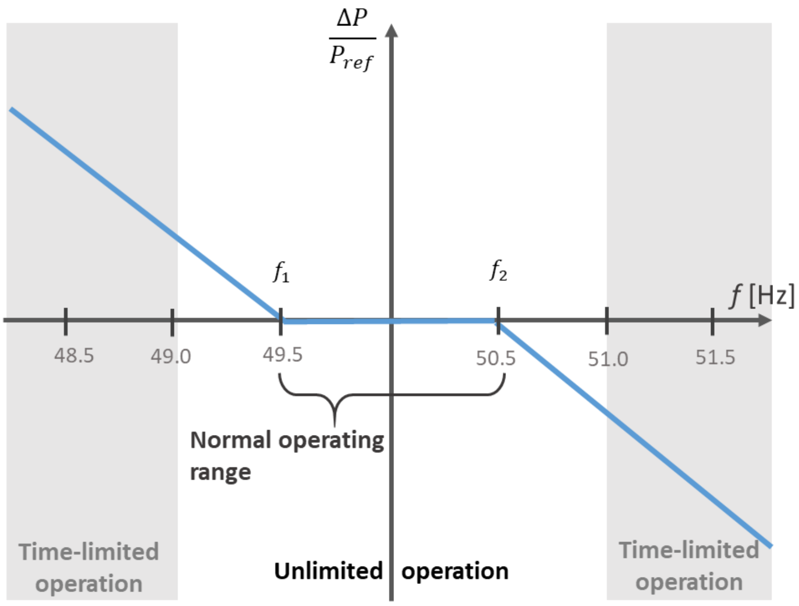

FIGURE 4. Example of Low/High-Frequency Ride-Through and Response Requirements (Energynautics)

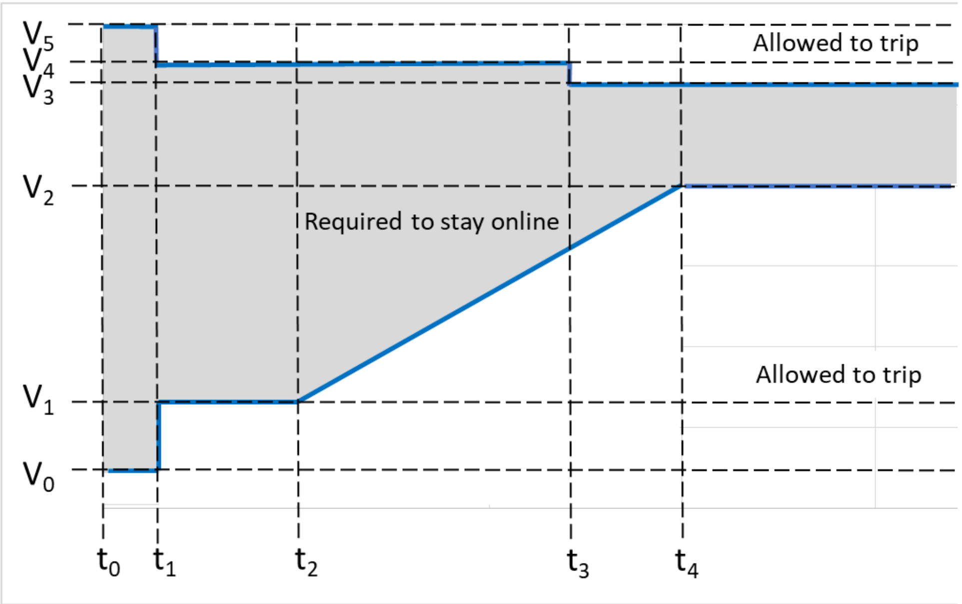

FIGURE 5. Low/High Voltage Ride-Through Requirement with Time Points and Voltage Set Points Defined by Standards or Local Grid Code (Energynautics)

On the other hand, **state-of-the-art inverters** (also sometimes referred to as smart inverters) offer a wide range of capabilities to support the electricity system, providing new tools for system operators to deal, inter alia, with high DG penetration levels in distribution systems. Furthermore, the implementation of most capabilities comes at zero, or very low, additional cost and can enable greater flexibility compared to conventional generation. In the long-term, this may enable the participation of larger DG plants in the provision of ancillary services, such as frequency and voltage control.

TABLE 2 provides an overview of recommended requirements for inverter-based renewable DG (e.g., PV and wind power plants) that should generally be requested for a DG installation. Although it is recommended that all inverters in a system have these capabilities, the actual utilisation of some of them may not always be an optimal solution, especially in systems with low DG and RE penetration. On the one hand, some of them may have negative side effects for DG owners, such as increased losses or possible reduction of generator output (i.e., curtailment) while, on the other hand, they could have high associated costs for system operators; for example, enabling communication capability (so that the system operator has the possibility to intervene in the operation of the DG installation for reliable operation, e.g. during emergency situations, grid congestion, etc.), would require the system operator to set up a communication network that could involve high costs. In conclusion, having inverters with a wide range of capabilities is an easy step that can be taken with no significant additional effort for the DG owner – whether these are actually in use in the system will have to be considered by the respective system operators as regards costs and benefits.

TABLE 2. Recommendations on Requirements for Inverter-Based DG (in line with IEEE 1547-2018)

REQUIREMENTS OF INVERTER CAPABILITY	RECOMMENDED REQUIREMENT	RECOMMENDED UTILISATION
Low/high frequency ride-through	++	++
Frequency response	++	++
Low/high voltage ride-through	++	++
Reactive power provision	++	++
Reactive power control modes	++	++
Active power control modes	++	Only in critical distribution feeders
Ramp rate limitations	+	+
Communication capability	++	Only in critical distribution feeders

Note: + means recommended, ++ means highly recommended. See the IEEE 1547-2018 standard as a reference for specifications of inverter capabilities. For more information, see IRENA's report on the Role of Grid Codes (IRENA, 2016).

Good grid code requirements have been spearheaded by the Californian Rule 21 (California Public Utilities Commission, 2020), Hawaiian Rule 14H (Hawaiian Electric, 2020), as well as German and Australian grid codes. Depending on the grid code, a distinction can be made between DG source (as in Denmark), voltage level for connection (as in Germany) or DG size (as in Australia). Furthermore, the IEEE 1547-2018 standard (IEEE, 2018) may be used as a reference and adapted to the local characteristics.

Recommendations: Adopt good practices on DG grid codes early and with foresight, including requirements as outlined in **TABLE 2,** by adopting standards, such as IEEE 1547-2018 (IEEE, 2018), or by closely examining grid codes of power systems with high DG penetration levels (e.g. Germany, California, Australia).

4.2 Regulatory Limits for DG Integration

To avoid the adverse effects of DG, regulators have in the past used simple methods to avoid DG integration issues, which often consisted of limiting the maximum DG capacity that could be connected to a distribution feeder to a value of between 15% and 30% of the feeder's maximum load. This ensured that reverse power flows were almost impossible and therefore no overvoltage, overloading or protection problems were to be expected. In the USA, this regulation became known as the '15% rule'.

The 15% rule, and adaptations thereof, can still be found today in many power systems and in some systems, such as in some of the public utility commissions in the USA; other criteria for DG grid connection assessments have been introduced, such as a limit on DG capacity equal to 100% of the minimum feeder load.

Today, however, these regulations are known to place unnecessary limits on DG development, as it is often found that actual technical limits (defined by the maximum hosting capacity as explained in section 3.3, for instance) are much higher than these arbitrary rules. Therefore, the trend in the USA, and in other power systems, has moved towards the use of **integrated distribution planning tools to determine the maximum DG hosting capacity for each distribution feeder**.

FIGURE 6 shows an example of this type of analysis, which provides information on the minimum and maximum hosting capacity of a distribution network, depending on the location of DG installations. Power system operators in Hawaii or Mexico already publish maps that indicate the remaining DG hosting capacity on their networks (Hawaiian Electric, 2021; Comisión Federal de Electricidad, 2021). The use of such tools by utilities can improve network planning and increase the share of renewable distributed generation. A prerequisite for this is good data collection and processing by grid operators (further discussed in section 4.5).

Recommendations: As long as DG capacity remains low and only exceeds 15% of maximum load on a few feeders, it is sufficient to introduce supplementary evaluation criteria and standardise screening processes by DSOs. To achieve high penetration of DG capacity, more sophisticated screening methods become essential, such as the assessment of DG hosting capacity using integrated distribution planning tools, geared towards defining the actual technical integration limits.

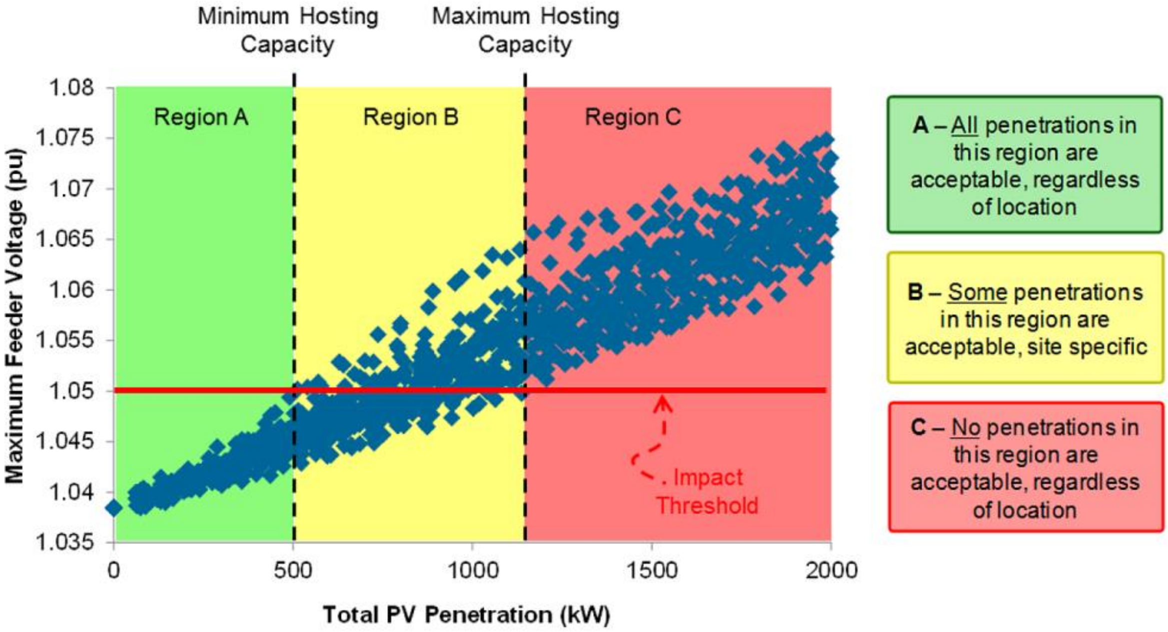

FIGURE 6. Visualisation of Hosting Capacity Assessment Results for a Specific Distribution Network as part of Integrated Distribution Planning (EPRI, 2015)

4.3 Network Optimisation before Network Augmentation

For distribution feeders that have reached their technically feasible maximum DG penetration level, there are good options available to increase the DG hosting capacity without having to invest in any network augmentation measures such as new distribution lines or transformers. This is often achieved **by optimising network operation** through reactive power control by DG inverters, or optimised transformer voltage control, for example (see section 3.2 for more details). Distribution system operators (or utilities) can therefore use these options whenever they see fit.

Recommendations: Regulators should ensure that network optimisation measures are considered in the distribution planning guidelines of utilities, as they often offer a cost-effective option compared to network augmentation. These measures can be analysed using power system analysis and integrated distribution planning tools. For some of these solutions, it will be a prerequisite that the DG installations have adequate capabilities for the DSO to take advantage of, so it is key to define these requirements in the grid code as early as possible.

4.4 Interconnection Charges

In most power systems, the DG applicant must make a one-time payment for connection to the grid. Typically, this fee only includes the cost of the connection to the nearest interconnection point, but in some cases, it may also include the cost of any required upstream reinforcements on the existing distribution grid. These cases represent the two main types of interconnection cost designs, known as **shallow** and **deep connection charges** respectively.

The implementation of **deep connection charges** can lead to a 'first come, first served' problem whereby DG applicants are allowed to interconnect as long as the regulatory or technical limit is not reached, but, thereafter, subsequent applicants would be prohibited from interconnecting or charged a high interconnection fee due to the necessary reinforcements. In this case, interconnection processes try to address this issue by grouping generator requests in order to distribute the reinforcement costs more evenly.

FIGURE 7. Connection Charges for DG in the EU (blue: shallow; green: shallowish; light blue: deep; hatched: other charging regimes (eurelectric 2018)

In the case of **shallow connection charges**, the reinforcement costs are spread across all network users, for example by allocating them as network charges in retail electricity tariffs. The disadvantage of this approach is that no location signal is given to applicants, so as not to further burden distribution networks that are already reaching their maximum hosting capacity. In countries such as Germany, where the right to interconnect a DG installation must be guaranteed for everyone, even if the maximum hosting capacity is reached, the utility must upgrade the grid to allow for the connection of new DG.

As explained above, each approach has its advantages and disadvantages, and the design of interconnection charges varies from case to case. While for small-scale DG applications shallow cost charges are much more common, for larger DG applications deep connection charges are often applied. In some countries, a combination of these two approaches (referred to as 'shallowish') may also be applied, where the applicant bears the connection cost to the nearest interconnection point, plus at least a proportion of the upstream reinforcement costs.

An overview of connection charges for DG in the EU is depicted in **FIGURE 7** by way of example, whereby the prevalence of shallow (and shallowish) connection charges socialises grid connection costs, thus helping to promote DG.

Recommendations: Carefully consider different interconnection cost design schemes and align them with the country's power system structure and policy goals. Ideally, cost allocation schemes should allow for a fair distribution of costs while not deterring DG applicants from connecting.

4.5 Simplified Interconnection Application Procedures

Simplified and standardised interconnection **application procedures are essential** to streamline the application process, reducing delays and keeping the workload for the utility as low as possible. In some countries, a grid impact study is required for each new application, which can lead to long backlogs of interconnection requests if utilities lack the capacity to process these studies. Countries such as the USA have therefore adopted **fast-track procedures** for small distributed generators below a specific threshold (between 0.5 MW and 3 MW in most states), as well as **screening methods** that require a grid impact study only if one of the screening conditions is not met. To further speed up the procedures and reduce the number of grid studies required, the California Public Utilities Commission (CPUC), for example, has recently adopted new **methods based on hosting capacity analysis** and **integrated distribution planning** (California Public Utilities Commission, 2017).

These examples of improved procedures can be complemented by **clear interconnection process guidelines**, including **strict deadlines** for both the applicant and the distribution operator, and potential penalties for delays, to avoid a backlog of interconnection requests. An example of the interconnection process and relevant deadlines is presented in **FIGURE 8** for the case of New York, as presented by NREL (2015).[2]

[2] As part of NREL's Distributed Generation Integration Collaborative, NREL offers a useful collection of Interconnection Standards, Application Management, and Technical Screening publications, webinars, and blogs.

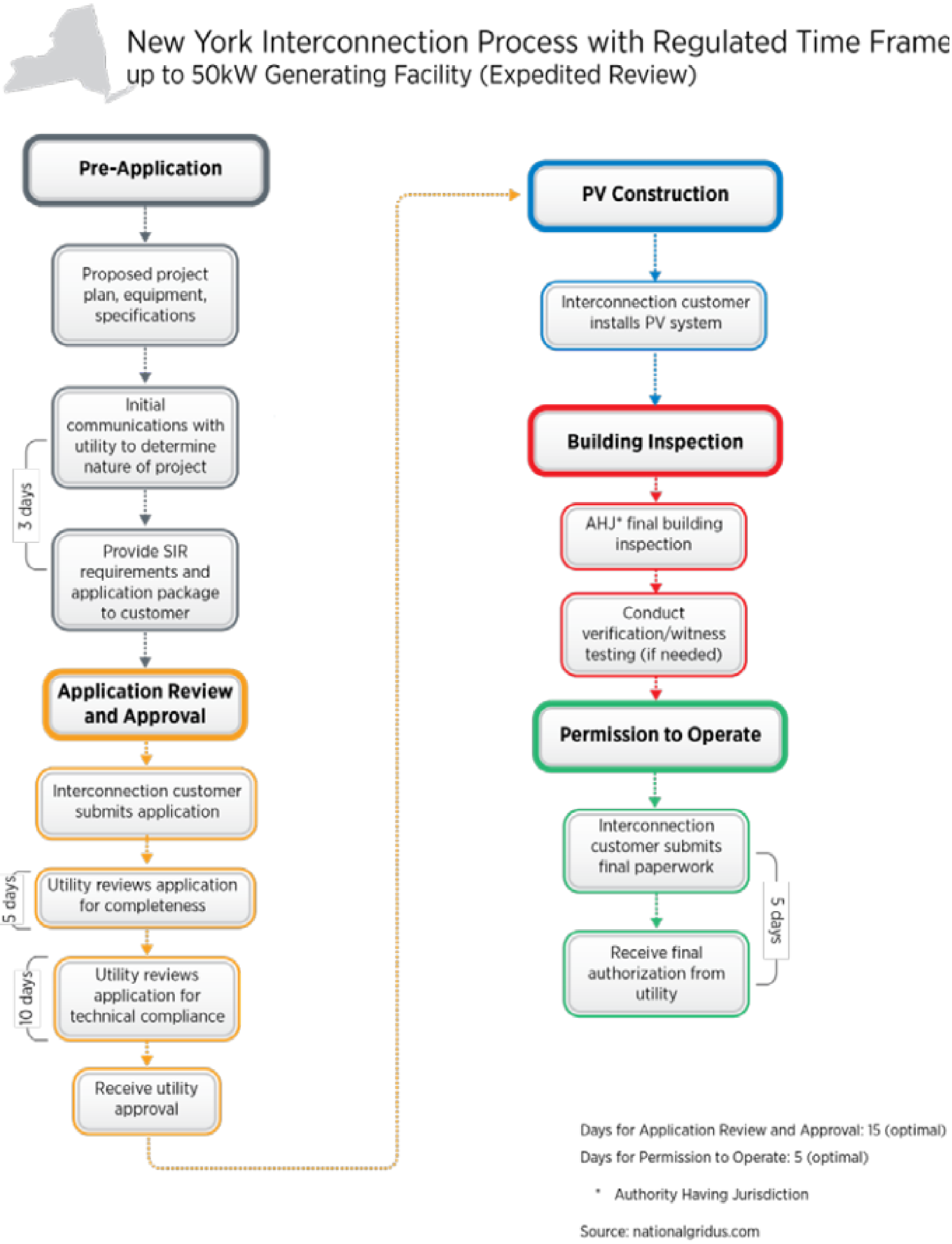

FIGURE 8. Example for New York's DG interconnection procedure with clear roles and deadlines (NREL, 2015)

Recommendations: Introduce fast-track and screening processes for small DG, combined with periodic hosting capacity assessments, to speed up interconnection application procedures. This should be accompanied by clear guidelines and deadlines for the interconnection process, and penalties for non-compliance should be considered to avoid delays by the respective applicants or system operators.

4.6 Standardised Data Collection

In some power systems, **data collection** has been inadequate or delayed, reducing the utility's insight into the actual impact that DG may have on the system. Therefore, it must be ensured that all **grid-relevant data** (capacity of both DG and inverter, geographic location, grid connection point, etc.) is collected to inform both the distribution utility and the transmission system operator about the geographic distribution of DG and its grid-related behaviour. This allows to properly account for DG in simulation models for **power system planning** or to determine the **remaining DG hosting capacity** in distribution networks. This is also important for **forecasting VRE production** and can be used as a basis for **updating grid code requirements** of existing or future installations. All these use cases of collected data help to optimise power system operation and planning.

Recommendations: Create a national registry of installations with clear data requirements to be met as part of the interconnection procedure. The data collected should be in line with the system operator needs and simulation models, including DG and inverter information (incl. capacity, control settings). Ensure that data starts to be systematically collected as early as possible, as it would otherwise be a major challenge to collect missing data after DG plants are interconnected.

5 Other Considerations

Besides the technical, interconnection, and regulatory considerations discussed in the previous sections, integrating renewable-based DG also requires assessing other economic factors. This includes understanding how market signals might incentivise DG development, including remuneration or billing schemes, such as net metering, net billing, and feed-in tariffs or premiums.

In addition, another element of economic regulation is the interplay between electricity tariffs and DG. Depending on the tariff design, DG self-consumption may have an impact on the revenues collected to maintain distribution grids. As concluded by Perez-Arriaga et al. (2016), flat volumetric tariffs are no longer adequate for the power systems of today. At the same time, the digitalisation of the power sector paves the way for new consumption patterns and tariff structures, such as time-of-use tariffs (through advanced metering infrastructure) which, coupled with storage, can influence self-consumption behaviour, so that it aligns with system needs.

Along with digitalisation and the expansion of communication capabilities at affordable costs, in the coming years, DG and other distributed energy resources, such as electric vehicles, could be aggregated (e.g., through virtual power plants) to minimise their impact and provide services to the system.

6 Further Reading

PUBLISHED BY	TITLE	PUBLICATION DATE
State-of-the-art grid code requirements		
IEEE	IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources – IEEE 1547-2018	2018
CPUC	Californian Rule 21	Frequent updates
Hawaiian Electric	Hawaiian Rule 14H	Frequent updates
EU Commission	Commission Regulation 2016/631 establishing a network code on requirements for grid connection of generators	2016
Grid code design		
IRENA	Grid Codes for Renewable Powered Systems	2022
World Bank	Grid Integration Requirements for VRE	2019
IRENA	Scaling-up Variable Renewable Power: The role of grid codes	2016
Interconnection procedures, charges, planning, technical screening		
NREL	Collection of Materials: Interconnection Standards, Application Management, and Technical Screening	Several
NREL	Review – Interconnection practices & costs in Western States	2018
MADRI	Integrated Distribution Planning for Electric Utilities – Guidance for Public Utility Commissions	2019
NREL	Updating Interconnection Screens for PV System Integration	2012
Examples of distribution system studies		
GIZ	Permissible PV Penetration in the Distribution Grids of the Dominican Republic (Spanish)	2021
University of Melbourne	Australian ARENA project – Advanced Planning of PV-Rich Distribution Networks Study	2019 – 2021
GIZ	Study on Integration of Distributed PV in the Electricity Distribution System in India	2017
IEEE	Guideline for distribution impact studies – IEEE 1547.7-2013	2013
Regional Ministry	Distribution system study, Rhineland-Palatinate (Germany)	2014
Key challenges and solutions for DG		
NREL	Collection of Materials: Technologies & Methods for Mitigating DG impacts, Business Models, Economics, Regulation	Several
World Bank	From Sun to Roof to Grid: Distributed PV in Energy Sector Strategies	2021
IRENA	Innovation Landscape briefs: Enabling technology briefs, System operation briefs, Market design briefs	2019 – 2020

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