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# Capacity of Distribution Feeders for Hosting DER

## Working Group C6.24

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# CAPACITY OF DISTRIBUTION FEEDERS FOR HOSTING DER

WG C6.24

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# EXECUTIVE SUMMARY

### Introduction

The last two decades have seen an unprecedented development of distributed energy resources (DER) all over the world. Several countries have adopted a variety of support schemes (feed-in tariffs, green certificates, direct subsidies, tax exemptions etc.) so as to promote distributed generation (DG), especially those exploiting renewable energy sources (RES). Under these circumstances, Distribution Network Operators (DNOs) are experiencing a strong pressure to respond to an often excessive demand for access to the network, while at the same time ensuring that DER connection does not violate the technical standards of the networks. To address this need in a timely and effective manner, simplified methodologies and practical rules of thumbs are often applied to assess the DER hosting capacity of existing distribution networks, avoiding thus detailed and time consuming analytical studies.

The scope of the CIGRE WG C6-24 was to study the limits of distribution feeders for hosting DER and the derivation of practical guidelines for the connection of DER. For this purpose, the approach adopted by the WG was to study the technical evaluation practices adopted by DNOs all over the world, in order to identify suitable rules and methodologies, as well as the means currently available to increase the hosting capacity. Main results of this investigation are summarized in this Technical Brochure.

### Technical issues limiting DER hosting capacity

Technical issues that limit DER hosting capacity of distribution networks are briefly presented in the following. They include the thermal ratings of network components, voltage regulation, short circuit level and power quality considerations, while additional constraints may arise from islanding considerations and the possibility for reversal of power flows.

Thermal ratings: Each element of the distribution network (lines, transformers etc.), is characterized by a maximum current-carrying capacity (thermal rating). Connection of DER has the effect of changing current flows in the network, which may lead to violation of the loading levels of network elements, especially under maximum generation and minimum load conditions.

Voltage regulation: Voltage regulation is primarily achieved through on-load tap changers (OLTC) controlled by automatic voltage control (AVC) schemes at the HV/MV substations, as well as by step voltage regulators (VR) installed along MV feeders, while switchable capacitor banks may also contribute to this task. Although DER may have a positive effect, compensating voltage drops, high DER penetrations complicate voltage control and may lead to overvoltage situations. Another concern is the excessive tapping of OLTC and VR, which increases wear of the equipment and increases maintenance costs.

Fault level: Distribution networks are characterized by a design short circuit capacity, which corresponds to the maximum fault current that can be interrupted by the switchgear used and does not exceed the thermal and mechanical withstand capability of the equipment and standardized network constructions. Since DER contribute to the fault current, their interconnection may lead to exceeding the short circuit capacity of the network.

Power quality: DER installations may induce power quality disturbances, which mainly include fast voltage variations due to switching operations, emission of harmonics and flicker. Disturbances depend very much on the type and technology of DER equipment, as well as on the characteristics of the network and may impose limits to the hosting capacity of specific networks.

Other technical constraints: Reversal of power flows in the network may have a negative effect on certain types of tap changers and on the operation of voltage control schemes. Islanding is a serious consideration in distribution network, which often leads to conservative approaches for the acceptable capacity of DER. Additional technical requirements are also imposed concerning the effect on mains signaling systems, protection etc.

**Evaluation practices applied by DNOs**

All DNOs carry out studies that evaluate whether the connection of DER violates the rating of network elements, such as the nominal capacity of HV/MV and MV/LV transformers and feeder thermal ratings. Several DNOs define hosting capacity as a percentage (e.g. 65% or 50%) of HV/MV transformer capacity or the thermal limit of MV feeders. Similarly, a range of 50% to 100% of the rating of MV/LV transformers is applied as a limit in several countries.

DER penetration limits are often expressed as a fraction of feeder capacity. In shared LV feeders (i.e. feeders serving consumer demand) the aggregate DER nominal power should not exceed 25% of the nominal power of the transformer. In dedicated LV feeders, aggregate DER nominal power should not exceed 75% of the circuit breaker rating.

It is also a common requirement that the aggregate DER capacity within the MV network of a HV/MV substation should not exceed the installed transformer capacity of the substation at N-1 conditions, possibly taking into account the annual minimum substation load (correction coefficients may apply, further limiting the hosting capacity). In some cases an even stricter criterion is applied, to avoid reverse power flows where the power transformers can't support such an operation.

Ensuring that the short circuit capacity remains below the design fault level is always a fundamental consideration, particularly near the MV busbars of the HV/MV substations. In certain cases, the fault level is used to formulate DER penetration criteria, e.g. by imposing a constraint that the DER contribution to the short circuit should not exceed 10% at the PCC.

Another important criterion applied universally is the effect of DER on voltage regulation. Voltage levels in extreme operating conditions, typically at maximum load – no generation and at minimum load – maximum generation, are assessed to ensure than operating constraints are met. The aggregate voltage rise due to all DER connected to the network is also limited by many DNOs, usually to 2%

Several DNOs carry out studies so as to evaluate the impact on the losses of the network by the connection of DER. Certain DNOs require that the interconnection of DER does not lead to an increase of network losses.

Criteria related to power quality disturbances, such as fast voltage variations, flicker and harmonics emissions, are also employed, either as simplified screening rules or within more elaborate evaluation methodologies. Simplified approaches adopted for avoiding undesirable impacts on power quality consist in limiting DER capacity to a fraction of the short circuit capacity at the PCC, e.g 10% or 5% for wind power plants.

Islanding considerations are often an important limiting factor, leading to the adoption of conservative generation to load ratios, implemented in both LV and MV networks to determine hosting capacity. Such simplified rules are commonly encountered in USA and Canada.

In general, simplified screening criteria, e.g. based on generation to load or short circuit contribution ratios, often incorporate substantial safety factors and are used as fast and simple first-step procedures when conducting interconnection feasibility studies. When such criteria are not met, specific and more detailed studies may need to be carried out.

**Means available to increase DER hosting capacity**

In order to relax the DER capacity limiting constraints and hence increase the hosting capacity of distribution networks, DNOs apply practices which can be summarized as follows:

Network: Reinforcement and rearrangement of existing network, as well as the construction of new installations (shallow and deep connection) are the most commonly applicable means to accommodate the increased demand for connection of DER. Some countries have adopted the practice of building new substations dedicated to the connection of DER only.

Short circuit: Solutions are promoted that reduce the short circuit contribution of DG, such as generating units with lower fault current, transformers with higher impedance and series reactors, or of the network, mainly by increasing the HV/MV transformer impedance. The installation of fault current limiting devices is possible but not widely favored. Upgrading the network switchgear is also a possibility, although it is a rather expensive and usually impractical solution.

Voltage regulation: Readjustment of settings for on load tap changers (OLTC), step voltage regulators (VR) and fixed taps of MV/LV transformers, along with the application of improved voltage control schemes and cancellation current transformers (CTs) for the OLTCs, are standard solutions. Replacement of HV/MV transformers with others equipped with larger tap ranges is also considered, whereas the addition of OLTC to MV/LV transformers is being discussed as an option for the future. Replacement of fixed capacitor banks on the feeder with switchable ones, or even the installation of reactive power sinks (reactors) on the network, can be applied to prevent overvoltages.

DER power control: Controlling the power factor or the reactive output power of DER is an effective way to mitigate voltage rise and regulation problems, which is increasingly adopted by DNOs. Different implementations are encountered, ranging from adjusting the output power factor to a suitable constant value, to varying the power factor depending on the active output power or the terminal voltage. Active voltage regulation by DG is a possibility, but still not adopted in practice. Active power curtailment to address overvoltage issues is also possible but it is not frequently applied due to economic and commercial implications.

Reverse power flow: Modifications to allow bidirectional power flow, such as readjustment of control settings of voltage regulators, replacement of breaker protection relays or reclosers etc.

Other: Coordinated voltage control via remote supervision and control of network regulation means and DG stations, which requires suitable communication infrastructure, is envisaged as a solution for the near future. Demand response and the installation of decentralized storage for voltage regulation purposes and relieve of network congestion are also contemplated as future possibilities.

# INTRODUCTION

The demand for the connection of Distributed Energy Resources (DER), mainly renewables, at the Medium Voltage (MV) and Low Voltage (LV) distribution networks is constantly growing, due to the drive for increasing renewable energy penetration in the energy mix and the favourable support policies adopted in many parts of the world.

In many countries, Distribution Network Operators (DNOs) are overwhelmed by unprecedented amounts of DER connection applications, which need to be evaluated in a fast and reliable manner. At the same time, local DER production often exceeds the loads of the lines and substations, especially at low load periods, causing reversal of flows and power in-feeds to the upstream networks. This situation can potentially cause several problems, including voltage regulations issues, low power factors at the HV/MV substations, power quality concerns, high short circuit levels etc.

Due to those reasons DSOs are reluctant to grant permissions to connect DER, unless detailed studies of individual feeders are performed. Such studies cause significant delays to DER integration and numerous complaints by the DER developers and investors. Hence, the need arises for simplified methodologies and practical rules of thumb that will allow DSOs to assess the hosting capacity of the distribution network in a fast but reliable manner, without the need to resort to detailed analytical studies.

The scope of the CIGRE WG C6-24 was to study the limits of distribution feeders for hosting DER and the derivation of practical guidelines for the connection of DER. For this purpose, the approach adopted by the WG was to study the technical evaluation practices adopted by DSOs all over the world, in order to identify suitable rules and methodologies.

**Table 1: DNO practices included in the Technical Brochure**

| Continent | Number of countries | Countries |
|---|---|---|
| Africa | 1 | South Africa |
| Asia | 3 | China, Japan, South Korea |
| Australia | 2 | Australia, New Zealand |
| Europe | 13 | Austria, Belgium, Czech, Denmark, France, Germany, Greece, Ireland, Italy, Norway, Portugal, Spain, UK |
| North America | 2 | Canada, USA |

Main results of this investigation are summarized in this Technical Brochure.

In Chapter 1, the technical issues arising from the connection of DER to the distribution networks are briefly described, since they are the main factors that eventually limit the hosting capacity of the networks. These include the thermal rating of the components, voltage regulation, short circuit current, reverse power flows, power quality issues, islanding considerations and others.

In Chapter 2, the practices followed by DNOs in several countries are presented. The main focus is on simplified rules, practical approaches and rules of thumb adopted worldwide, rather than on detailed evaluation methodologies. Publicity practices adopted by DNOs, in order to inform stakeholders about the overall and remaining hosting capacity of their networks, are also discussed in this chapter.

In Chapter 3, a discussion is provided on means available to increase the hosting capacity of the networks. Again, a presentation on a country by country basis is made. The emphasis is mainly on solutions suitable for application today, which may be implemented either in the network or in the DER facilities.

In Chapter 4, a synopsis of the criteria and solutions is provided, grouped according to their nature and field of application.

# CHAPTER 1 - OVERVIEW OF TECHNICAL ISSUES LIMITING DER HOSTING CAPACITY

Over the last years, significant steps have been made towards promoting the use of renewable energy sources and the integration of such resources to the electricity networks. Nevertheless, interconnection of DER to the network, especially at high penetration levels, raises important technical issues. In order to mitigate against possible implications related to the high penetration of DER, DNOs have established evaluation methodologies based on technical criteria including the thermal ratings of network components, short circuit contribution and resulting fault level, voltage regulation, power quality (flicker, harmonics) etc. These criteria ensure the integrity, security of operation and safety of the networks but still constitute limits for the DER hosting capacity of the networks. In the following pages, technical issues related to the interconnection of DER to the network are described.

### Thermal ratings

Each device or element of the existing distribution infrastructure (lines, cables, transformers etc.), is characterized by a current-carrying capacity [1]. If this limit is exceeded a sufficient time, [2] overheating will occur and its physical and/or electrical characteristics may be irrevocably degraded [1]. The current carrying capacity of the device is referred to as its thermal rating. Loading a device beyond its thermal rating may lead to permanent damage, or even initiate a fire or explosion. Connecting DER to a distribution network has the effect of changing the current flows in the network. With a suitable choice of site and connection scheme, connection of DER can have a beneficial effect, with no increases in current levels, and in some cases, significant reductions. Although this is clearly a desirable outcome, it is not always possible or cost-effective. In many cases, the most “convenient” connection design results in higher current levels in parts of the system [1]. These currents may cause the loading levels of individual elements (transformers, lines and cables) [3], [4] to increase, specifically in cases of maximum generation and minimum load. It is important therefore to check what rating is being quoted, continuous – 100% rated current for 100% time, or cyclic based on a specific load shape, duration, seasonal variation etc [5]. In these cases, the developer may opt to pay for these existing assets to be reinforced or up-rated. However, if the cost of this reinforcement is very high, it may be worth considering an alternative connection arrangement, possibly at a higher voltage level. The connection of DER to high voltage systems is less likely to be constrained by thermal ratings than connections made to lower voltage systems [1].

### Voltage regulation

Voltage regulation on distribution networks is currently achieved mainly through on-load tap changers controlled by automatic voltage control (AVC) schemes at each transformation point down to the MV busbars of a primary substation. These AVC schemes will typically maintain the busbar voltage at slightly higher than nominal voltage to allow for voltage drop along the outgoing feeders [5], [6]. The presence of distributed generation can assist in improved voltage profiles, but often makes the process of voltage control more complex [5]. Examples of potential operating problems are provided below [7]:

- Low voltage
  Most feeder regulators are equipped with line drop compensation (LDC) that raises the target regulator output voltage in proportion to the load. This feature helps to maintain constant voltage at a point further downstream by raising the regulator output voltage to compensate for line voltage drop between the regulator and the load center. A DER located immediately downstream of a feeder voltage regulator may interfere with the proper operation of the regulator, if the generation output is a significant fraction of the normal regulator load. When the DER offsets 15% or more of the load current, this causes the regulator to set a voltage lower than required to maintain adequate service levels at the end of the feeder. The impact on feeder voltage regulation is as follows [8]:

- ✓ The feeder may be heavily loaded, but the regulator sees relatively low load due to the DER current offset
- ✓ The line voltage drop from the DER to the load center still reflects heavy loading, but the regulator output voltage is not increased because of the low loading seen by the regulator.
- ✓ As a result, low voltage can occur at the load center.

- High voltage
  During normal radial feeder operation, there is a voltage drop across the distribution transformer and the secondary conductors, and voltage at the customer service entrance is less than at the primary. Under certain conditions with a DER unit installed, other customers on the feeder may see higher than normal service voltage with associated unintended consequences. This situation can occur when [8]:
  - ✓ A DER unit (such as in a small residential DR system) shares a common distribution transformer with several residences.
  - ✓ The distribution transformer serving these customers is located at a point on the feeder where the primary voltage is near or above the upper acceptable limit.
  - ✓ The DER introduces reverse power flow that counteracts the normal voltage drop, perhaps even raising the voltage.

- Conflicting voltage regulation objectives and effect on voltage control
  The OLTC of HV/MV transformers typically increases the MV busbar voltage in order to counteract the voltage drop induced by the load along the MV distribution feeders. This regulation practice is not suitable for MV feeders with substantial generation, where the voltage rise along the feeder would require a reduced busbar voltage. Further, in HV/MV substations with large amounts of connected DER, increased levels of local generation may mask the load level perceived by the OLTC voltage regulator at the substation, leading to under-regulation of the voltage even at high load periods.

- Excessive operations
  The introduction of a DER - especially one with a fluctuating source, such as wind or solar - can disrupt normal operation and interact with voltage-regulating devices. Multiple voltage regulating devices are commonly used on MV networks and it is necessary to coordinate their timing. DER device output changes may disrupt the timing of voltage regulating devices and contribute to excessive tap changes or capacitor switch operations. To minimize problems, it may be desirable to change the time-delay settings on voltage regulating devices to provide better coordination with the DER device. In extreme cases, the installation of static VAr compensation or a similar device may be necessary [7].

**Fault level**

Every point in a distribution network has a particular fault level, which is a measure of the maximum fault current expected at that point. Fault currents need to be quickly detected and interrupted, as they present a risk to life and can cause extensive damage to cables, transformers and other equipment, as well as affect the supply of electricity to consumers [5]. Changes to the network, such as the connection of new DER [1], [2] loads or circuits, can cause increase in maximum fault levels [1]. The presence of DG provides an additional contribution to the fault level, and the embedded nature of the DG makes fault current calculations more complex as they should take into account the consequences of operational switching combinations to a degree not required when all generation was via the transmission network [9]. However, the fault rating of existing circuit breakers places an upper limit on the maximum fault levels that can be permitted in a particular part of the network [1]. This upper limit is sometimes referred to as the design fault level for that point of the network [1], [5]. The extent of the fault current that can be safely accommodated by an electricity network is usually determined by the rating of existing switchgear in the vicinity of the point of connection [2]. Design fault levels in distribution networks can sometimes be a limiting factor to the connection of new generators or loads, as illustrated in Fig. 1 [1], [2], [10].

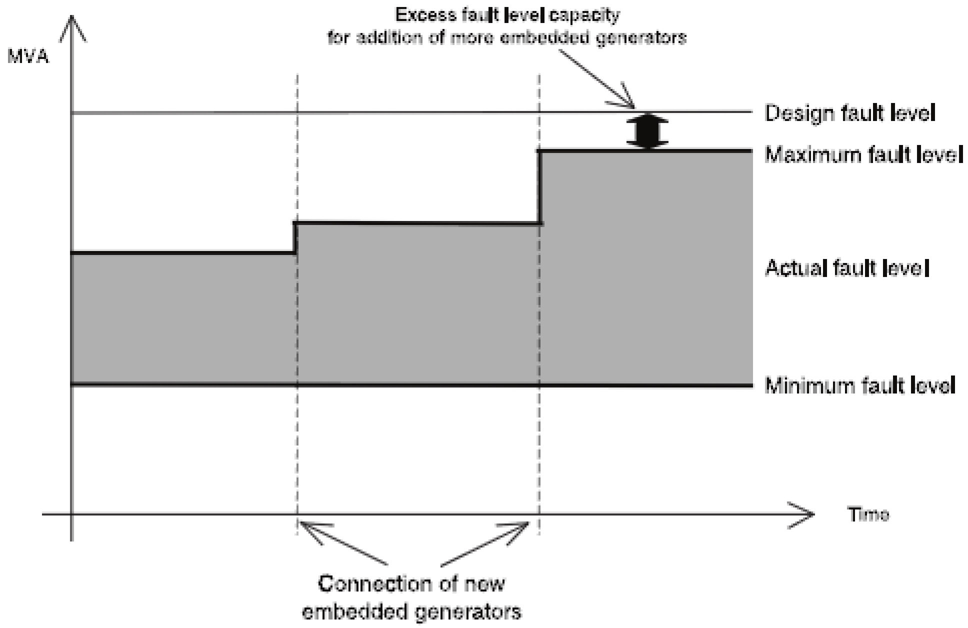



**Fig. 1 Impact of DER on actual fault level and DER hosting capacity based on design fault level** [1]

The fault level contribution from DG is determined by a number of factors, including [9]:

- The type of DG, since different types of DG contribute different fault currents.
- The distance of the DG from the fault, as the increased cable impedance over longer distances will reduce the fault current,
- Whether or not a transformer is present between the fault location and the contributing DG (which is often the case for voltage regulation purposes), since transformer short circuit impedance may assist in limiting the fault current,
- The configuration of the network between the DG and the fault, as different paths for the flow of the fault current will alter the magnitude of the fault current (due to cable impedances and other installed equipment),
- The method of coupling the DG to the network. DG with directly connected electrical generators will contribute significantly higher fault current than DG connected via power electronics interfaces.

**Reverse power flows**

Since the 1950s, the design and operation of most electricity distribution networks has been based on the key assumption that network power flows will always be from a higher voltage network to a lower voltage network [1], [6], [11]. However, this ‘rule’ has been changed by the recent development of renewable electricity generation and other DER (e.g. CHP and waste-to-energy schemes). Increasing levels of DG can lead to the export of power when the DER output exceeds local demand of the network, in which case the local transformers will experience reverse power flows up to the next voltage level [1], [6], [7], [11]. In these cases, the generator exports more than enough power to supply all the loads on the system to which it is connected and the surplus power is transferred back through a distribution or zone substation transformer and is fed into a higher voltage system [1]. There are two main factors which limit the reverse power flows allowable on a particular network. The first is the reverse power rating of the primary plant, such as transformers, and the second one is the ability of the network’s automatic control systems to respond correctly under reverse power flow conditions [6].

The possibility of reverse power flows in transformers can sometimes present a problem with the operation of the transformer’s automatically controlled tap changers fitted to provide voltage regulation on the low voltage side of the transformer. When OLTCs with single resistor bridging [5], [6], [12] are used on the primary side, the regulator’s ability to carry reversed power flows may be reduced to anywhere between 30% and 70% of the transformer's normal thermal rating. However, most modern tap changers do not have this restriction since they are based on designs using two diverter switch resistors [5], [6]. Moreover there is an issue related to the number of tap changing operations due to the variation of DER's power injection to the network [12].

However, the most critical issue is the type of voltage control scheme that is used to operate these tap changers. Most of the commonly used voltage control schemes operate perfectly well with reverse power flows, but there can be problems with certain schemes [1]. Voltage control schemes, in the form of Automatic Voltage Control (AVC) relays, are normally applied to HV/MV transformers. Some DNOs also use line drop compensation or negative reactance compensation to provide improved operation under loaded conditions or when operating transformers in parallel. Both rely on the measurement of transformer load current and therefore may be affected by flows of reverse power [5], [6]. When load current compounding is used with the AVC and the penetration level of DER becomes significant compared to loads, it may be necessary to switch any compounding out of service. DER can cause problems if connected to networks employing AVC schemes which use negative reactance compounding and line drop compensation due to changes in active and reactive flows [11].

Many voltage regulators have reverse power flow sensing, which reverses the control algorithm. This action is based on the assumption that the direction from which power flows is the strong source location (from a short-circuit strength standpoint). Reverse flow sensing is used on feeders that have alternate sources on the other side of the regulator as the normal source. Sensing reverses the control algorithm so that correct regulation can be provided when the alternate source is used. A DER can reverse power flow, but it does not typically provide a source strength stronger than the substation. Reversal of the controlled bus will cause the regulator control to move the tap to the limit in one direction or the other because the tap change produces a voltage change opposite from what the control algorithm expects. As a result, customers on the DR side of the regulator can experience very high or very low voltage. The only solution is to disable the reverse flow sensing if the DER is of sufficient size to cause reverse flow at the line regulator under any foreseen load conditions. This compromises the ability of the regulator to perform its function under alternate feed conditions [7].

There have also been reports of transformer directional overcurrent protection operating due to reverse power flows. This protection normally has a low current setting and therefore a potential limiting factor [6].

The reverse power flows through MV/LV distribution transformers will only be limited by the full load rating of the transformer, since these transformers have off-load tap changers.

**Rapid voltage change (RVC)**

Rapid voltage changes can be caused by variation in generation output, tripping of plant and switching of devices. For relatively stable generating plants, such as a combined-heat and power (CHP) unit, cogeneration or concentrated solar plant (which seldom trips), a less strict RVC value can be applied, because rapid output changes and tripping of plant occurs infrequently, than for generating plants such as solar PV and wind, their output power where generation changes rapidly.

**Islanding**

Island forms when a generator continues to supply the load in a part of the network disconnected from the upstream grid. Safety measures called Anti-Islanding (AI) requirements have been defined and embodied in standards to provide guidelines for testing the performance of automatic islanding prevention measures installed in or with DG interconnection components. For instance, IEEE 1547-2008 requires that the DG interconnection system detects an islanded condition and ceases to energize the area EPS within two seconds after the formation of an island. IEEE 1547.1-2005 describes also a test procedure that is intended to verify that the DG meets this requirement. However, it is important to note that this test procedure involves the testing of a single DG unit, which is a somewhat idealized scenario for which reliable islanding detection can be achieved relatively easily. More realistic scenarios involve the connection of multiple DG units in parallel - for this scenario, reliable islanding detection is much more difficult to achieve.

A severe implication of islanding is the possibility for self-excitation. This will occur when induction generators are connected to a line having sufficient capacitance to supply excess reactive power, leading to Over Voltages (OV), created by charging and discharging of the islanded system capacitance through the magnetizing reactance of the induction generators. The OV magnitude will also depend on the active power equilibrium in the isolated part of the network. In general, such OV can be sensed by the protection relays of the generating facilities.

Most generators are equipped with Under/Over voltage and frequency relays which can detect the islanding condition in case of active (P) and reactive power (Q) mismatch. In the case where P and Q match, the voltage and frequency of the island will not deviate from the nominal values, hence, the Under/Over voltage and frequency relays might not detect the islanded condition, hence, advanced islanding detection methods are required. Islanding detection methods can be classified mainly into two categories: Local and Remote. Local methods are further divided into two subcategories as passive and active methods. Local techniques rely on the data that are available at the DG location. Passive methods depend on measuring certain system parameters and they do not interfere with DG operation. Several passive techniques proposed are based on monitoring voltage magnitude, rate of change of frequency, phase angle displacement, and impedance. If the threshold for the monitored quantity is set to too low then nuisance tripping becomes an issue; and if it is set to too high, islanding will not be detected at all. In active islanding detection methods, DG operation is controlled by using positive feedback of either voltage and/or current. Below is the list of the islanding detection methods that have been researched recently:

<u>Local Methods</u>

Passive Detection Techniques

- Under/over voltage and under/over frequency
  For islanding, these relays must cease the operation of the DG when the utility grid is isolated from the DG. The deficit or surplus of active power and reactive power is ΔP and ΔQ, respectively. The behavior of the system at the time of utility disconnection depends on ΔP and ΔQ at the instant before the island is formed. If Δ*P* ≠0 and ΔQ ≠0, then the amplitude of frequency and voltage at the PCC will change and UVP/OVP will detect this change and trip the DG source. This change in frequency is detected by UFP/OFP. Modern Rate of Change of Frequency (ROCOF) and Vector surge (VS) relays will also detect this event.

- Voltage phase jump detection
  The Phase Jump Detection (PJD) method involves monitoring the phase difference between voltage at the PCC and inverter output current. This method can be applied to the Current Source Inverter (CSI) by synchronizing the inverter current to the utility voltage during normal operation. In the case of Voltage Source Inverters (VSI), the roles of current and voltage are interchanged. However, the setting of thresholds for the PJD method is difficult and as a result this method is prone to nuisance tripping

- Detection of voltage unbalance and total harmonic distortion
  This method employs two parameters for detecting islanding condition of DG. (1) Voltage Unbalance (VU) and (2) Total Harmonic Distortion (THD) of the current. The sudden change of DG loading caused by islanding (assuming that a large fraction of the load during pre-islanding was supplied by the grid) causes voltage fluctuation. Furthermore, the disconnection from the grid results in a weaker system, which makes the system more susceptible to variations such as voltage fluctuation and harmonic distortion.

Active Detection Techniques

- Impedance measurement
  This method is developed for inverter based DG, such as PV. The current output of a current-controlled PV inverter is:
  $$i_{PV-inv} = I_{PV-inv}\sin(\omega_{PV}t + \phi_{PV})$$
  The equation shows that amplitude, frequency, and phase are the three parameters that can be varied. This method tries to impose variation in one of these parameters. The perturbation in voltage indirectly results in perturbations in power and the perturbation in power is used to determine the resistive part. The

perturbation in Q determines the inductive part of the grid impedance. If the utility grid is disconnected, this variation will force detectable change in voltage at the PCC that can be used to detect islanding conditions.

- Detection of impedance at a specific frequency
  This method is a special case or an extension of the passive harmonic detection method. This method intentionally injects non-characteristic harmonic currents via the DG inverter which are dependent on grid impedance at that specific frequency. This method is prone to the nuisance tripping problem if multiple inverters are in the system. The NDZ of this method is similar to the NDZ of the passive harmonic detection method.

- Slip mode frequency shift (SMS)
  Slip Mode frequency Shift (SMS) is one of the few methods that use positive feedback to detect islanding conditions. The basic idea is to use the positive feedback to destabilize the inverter when the system is islanded thereby causing the inverter to trip. SMS can be applied to the amplitude, frequency, and phase of the voltage at the PCC.

- Frequency bias or Active Frequency Drift (AFD)
  For this method, the waveform of the inverter current injected into the PCC is slightly distorted with respect to the utility voltage. This method is easy to implement in PV power conditioner with microprocessor-based controller. Under islanding conditions the frequency of the utility voltage will drift up or down augmenting the natural frequency drift caused by the system seeking the load's resonant frequency. The frequency drift in the islanded condition could be detected by O/U frequency relays.

- Sandia Frequency Shift (SFS)
  This method is an extension of the AFD method where positive feedback is used to detect islanding. In the islanded state, the grid impedance is not available to prevent changes and the system is more sensitive to any fluctuations. Consequently, a change in frequency is increased further by the SFS and the frequency deviation escalates. Islanding is detected when the frequency exceeds a pre-specified threshold of the over frequency protective relay.

- Sandia Voltage Shift (SVS)
  SVS uses positive feedback on the amplitude of the voltage at the PCC. In the non-islanded state, there will be little or no effect when the power is reduced. When the utility grid is absent, there is reduction in voltage at the PCC. This reduction in amplitude of PCC voltage continues as governed by the load impedance's interaction with the reduced current. The reduction in amplitude of voltage at the PCC leads to a reduction in the inverter output current. This cascading effect reduces the voltage to the extent that it trips the under voltage protective relay.

- Automatic Phase Shift (APS)
  The development of this technique was motivated by the inefficiencies of traditional frequency-shift methods, such as AFD and SMS methods, in detecting islanding in the presence of some parallel RLC resonant loads. The Automatic Phase Shift (APS) method reduces this problem by utilizing an algorithm that keeps the frequency of the inverter terminal voltage deviating until the protection circuit is triggered.

- Negative-Sequence Current Injection Method for Islanding Detection
  This is another active method for islanding detection of a DG unit coupled to a utility grid through a VSC. It injects negative sequence current through the VSC controller and detects and determines negative-sequence voltage at the PCC by means of a Unified Three-phase Signal Processor (UTSP).

- GE Frequency Shift (GEFS)
  In this algorithm the reactive current reference is obtained through positive feedback from the frequency estimation algorithm with proper filtering and gain in order to maintain stability.

<u>Remote Techniques</u>

- Transfer Trip Scheme

The basic idea of this scheme is to monitor the status of each circuit breaker and recloser between the DG and the utility grid. If a breaker or recloser opens, this information is conveyed to the DG via a communication system and the DG trips. This scheme requires that each breaker/recloser has a receiver and a transmitter that can communicate reliably via a wired connection (e.g., fiber optic cables) or a wireless connection. If the communication infrastructure is not already in place, the costs for implementing this scheme can be very high and, consequently, this scheme is rarely used in distribution systems. However, a transfer trip scheme essentially has a zero NDZ; provided that the communication works reliably.

- Power Line Carrier Communication (PLCC)
  A signal generator at the substation continuously injects a signal into the line that is sensed by all DGs on the distribution feeder. The loss of the signal at the DG indicates a loss of continuity of the line caused by, for instance, the opening of a breaker. If loss of continuity is detected at the DG location, the DG trips to prevent an islanded situation.

**Protection**

Interconnection of DER to the grid introduces some protection challenges to the grid, which are the following ones:

1) If the generator does not produce a source for L-G faults on the distribution feeder, it might create over voltage on the unfaulted phases when the utility breaker has detected the fault and tripped, thus the feeder load has lost the ground source from the utility.

2) If the aggregate generation exceeds the load on the distribution bus, power will back feed into Transmission system. If the transmission system is ungrounded, detection of L-G faults on transmission system is problematic if the transmission side of the substation transformer is not equipped with zero sequence ground over voltage protective relay.

3) If the generator provides a ground source to the faults on the distribution feeder, the fault current contribution from the utility system to the fault will decrease. If the utility feeders have time-inverse over current relays, the operation time increases because of the decrease in the fault current contribution. This may result in mis-coordination with the upstream relays.

**Power quality**

The high DER penetration may affect adversely power quality, raising issues such as voltage fluctuations, flicker, harmonics and effect on mains signaling.

As far as PV plants are concerned, impact on power quality could be caused by voltage and power fluctuations due to the variation of solar radiation. The voltage fluctuation can cause excessive feeder voltage regulator operation at the substation. Hence, in order to reduce the impact of the cloud transients on the feeder voltage regulator operation, it has been proposed that the PV contribute to the regulation of the voltage at the PCC. Inverter manufacturers have shown interest on implementing the VAR control feature into the inverters to regulate the PCC voltage by controlling the reactive power flow from/to the inverter. Voltage regulators might not be able to compensate the voltage drop on the feeder due to the PV infeed hence, the voltage at the load might be low. If the number of active power sources (PV) on the distribution system increases without significant change on the available reactive power supply, the Power Factor of the feeder decreases at the locations close to the substation.

As far as Wind turbines are concerned, impact on power quality could be caused by the following:

Flicker: Varying active and reactive power generated by the wind turbine might impact the system voltage and create flicker on the distribution feeder. Most utility companies are mandated to comply with IEEE-519 or the relevant IEC-61000-series standards. The active power generated from the wind turbine might decrease the ratio of the active to reactive power flowing from the grid to the feeder load. Hence, the feeder Power Factor (PF) might be impacted.

Harmonics emissions may be a disturbing issue due to the use of power electronic converters for interfacing DER to the grid. Although converters are supplied with harmonic filters and advanced PWM techniques are always applied, in cases of large aggregation of such DER voltage distortion limits can be exceeded. It is worth mentioning that the evaluation and analysis of harmonics problems are quite complicated and do not fall in the routine investigations performed by the DNOs.

When a mains signaling system exist on the network, it is necessary to ensure that DER installations do not interfere with ripple control signals. This could happen if the DER alters the harmonic response characteristics of the network at the ripple frequency, excessively damping or amplifying such signals, or if the DER generate harmonics at this frequency.

# CHAPTER 2 - UTILITY PRACTICES (RULES, GUIDELINES, LIMITS)

## Australia

In Australia, each DNO follows its own guidelines in which the Operator outlines the technical requirements, the criteria, the limits and all issues related to the connection of the DER to the LV, MV and HV network. So, taking into account that the DNOs are many, the relevant technical brochures and other guidelines are also many [13]. A national accepted standard by all DNOs is AS 4777. As far as international standards are concerned, 61000-3-5,6,7 have been adopted [1].

The control of voltage levels in long or heavily loaded distribution networks is an important issue, due to the need to maintain supply of relatively constant voltages within prescribed tolerances to electricity users. Although DNSPs[1] endeavour to keep system voltage levels close to their nominal value, the actual voltage level will vary from point to point around the system and also with time as the load on the system changes. Conversely, power in-feeds from DER tend to increase voltage levels in the local network.

Transformers are used to connect the different operating voltage levels in these systems. The transformers are fitted with tap changers to keep the voltage output of the transformer constant by compensating for voltage changes on the input side. Some tap changer control schemes also compensate for voltage changes in circuits connected to the transformer lower-voltage system (known as line drop compensation) [1], [12] and some allow the use of two or more transformers in parallel (negative reactance compounding is one such scheme) [1]. Tap changers between transmission system voltages (≥ 66kV) are normally automatically controlled [1], [12]. The 22kV and 11kV distribution transformers that provide 415V to customers are normally fixed tap. Note that in sparsely populated areas, 33kV systems may be used to directly provide 415V. To ensure that customers are supplied at a reasonably steady voltage, the settings of the fixed tap transformers are designed for their location along the feeder and the range of customer loads expected in the area (refer to Fig. 2) [1]. Line voltage regulators may also be used at strategic locations along long distribution system feeders to regulate the supply voltages to customers [1], [12].

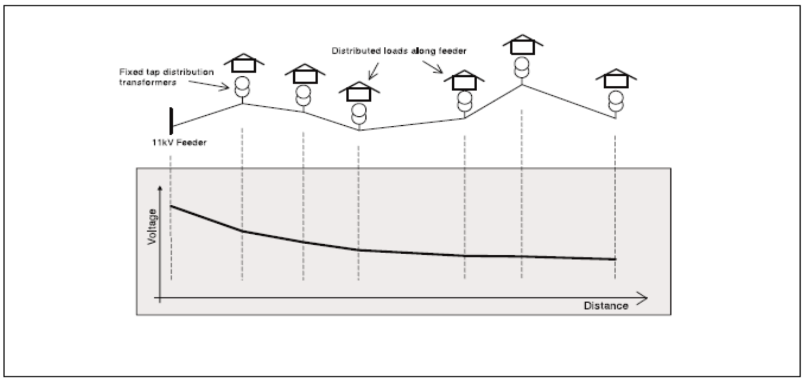



**Fig. 2 Voltage drop along an MV feeder** [1]

Due to the complexity of the networks and the amount of data involved, system studies are carried out using specialised computer software packages known as load flow software. The connection of DER to a distribution network will inevitably result in some local changes to the characteristics of the network. To evaluate the possible consequences of these changes, the DNSP will usually carry out some network studies with the DER included in the network model. In carrying out these studies, the DNSP engineers will be particularly interested in whether the proposed DER connection results in any of the following conditions [1]:

- Thermal ratings of equipment being exceeded.
- Unacceptable voltage rise in high voltage systems.

[1] Distribution Network Service Provider

- Fault level rating limits of existing switchgear being exceeded: Generally, DER are not permitted to push maximum fault levels beyond the network design fault levels [1]. The short circuit levels, that must not be exceeded, are shown in the following Table 2 [14]:

**Table 2: System fault levels (Australia)** [14]

| DISTRIBUTION SYSTEM FAULTS LEVELS | | |
|---|---|---|
| Voltage Level kV | System Fault Level MVA | Short Circuit Level kA |
| 66 | 2500 | 21,9 |
| 22 | 500 | 13,1 |
| 11 | 350 | 18,4 |
| 6,6 | 250 | 21,9 |
| <1 | 36 | 50,0 |

- Transformers operating with reverse power flows.
- Voltage fluctuations as a result of the generator connecting or disconnecting from the network.
- Stability on generation units under different conditions.

## Austria

In Austria, the basic technical framework is defined in the “Technical and organisational rules for operators and users of transmission and distribution networks (TOR)” [15]. Most significant are theTOR-Part D4 “Parallel operation of generation units connected to distribution networks” [16] and TOR-Part D2 “Recommendations for the assessment of network interferences” which have been replaced by the “Technical Rules for the Assessment of Network Disturbances” [17]. Further, there is a national standard that covers PV installations including their connection to the grid, the OVE ONORM E2750 “Photovoltaic power systems - Erection and safety requirements” [15]. As far as international standards are concerned, the EN 61000-3-2 and EN 61000-3-3 are adopted [16].

In Austria, the dominant criteria related to voltage is that the total voltage rise caused by all DER that are connected to the low and medium voltage networks must not exceed 3% and 2% of the nominal, respectively [16], [17]. In certain cases, the DNO may impose higher or lower limits depending on the specific conditions of each case. Since voltage regulation is currently usually performed only at the HV/MV substations through on load tap changers, the DNO must ensure that under low load conditions the voltage at all nodes does not exceed the upper limits and under high load ones does not fall below the lower limits. Additionally, the same must be ensured taking into account the connected DER [16]. The voltage limits are the ones presented in EN 50160 and the extreme cases that have to be assessed are the following [17]:

- maximum load without generation
- minimum load with maximum generation

A case study is presented in Annex A.

## Belgium

The technical guideline, which is used in Belgium, is the “Technical requirements for connection of dispersed generation systems operating in parallel on the distribution network” which was issued by BFE-FPE. It covers all relevant issues for connection of power plants with nominal power up to 15 MW [16].

According to the national standard for the connection of DER to the electric network, the DNO is responsible for the determination of the connection scheme taking into account the following considerations [16]:

- The voltage level of the network must be kept within the operating limits, whether or not the DER is present. If the voltage variation is lower than 3% due to the DER connection, no problems should be expected. Otherwise several feasible solutions should be adopted such as:
  - Network reinforcement.
  - Automatic voltage regulators.
  - Automatic power curtailment.
- The aggregate power of DER must not exceed the HV/MV transformer power taking into account that the N-1 criteria should be met.
- As for LV networks, the aggregate power of DER must not exceed the MV/LV transformer power rating.
- The power must be transmitted in such a way that the capacity of the network elements is not exceeded.
- As far as the short circuit issue is concerned, the contribution of the DER must not result in higher short circuits than the capacity of the existing equipment in the networks. In the case of connection to the MV network, the DER must be connected via a transformer, the characteristics of which shall be defined by the network manager. However, the short circuit impedance must be at least 10%, unless the network manager permits an exception for a capacity under 1.2 MVA. The transformer has a fourfold function: it protects the DER by absorbing surges, that may be caused by incorrect paralleling; it prevents the earth current going from the network to the generator in case of an earth fault; it attenuates peaks in the network caused by the generator and it reduces the short circuit contribution to the MV network by the installation. If the direct-axis transient reactance X'd of the generator or the total X'd in case of multiple generators is greater than 40% with reference to the generator, then a MV transformer is not obligatory for the connection to the network.

## Canada

In Canada, each DNO follows its own guidelines, setting the technical requirements, the criteria, the limits and all issues related to the connection of the DER to the LV, MV and HV network. There are cases where such guidelines are published by technical bodies of each province and are then adopted by the DNOs operating the networks. Further down, information relevant to various technical guidelines is provided.

- Alberta Distributed Generation Interconnection Guide [18].
- Technical Specification for Independent Power Producers [19].
- Interconnection Guideline, Customer Generation Capacity Not Exceeding 100 kW [20].
- Generation Interconnection Requirements at Voltage 34.5 kV and Below [21].
- Distribution System Code [22].
- CSA C22.3 No. 9 “Interconnection of Distributed Resources with Electricity Supply Systems” [23].
- Guide to Connecting Generators to Hydro Ottawa's Distribution Grid under the Feed in Tariff (FIT) Program [24].
- Distributed Generation Technical Interconnection Requirements (Interconnections at Voltages 50 kV and Below) [25].
- Technical Interconnection Requirements for Distributed Generation (Micro Generation and Small Generation - less than 30 kW) [26].
- Ontario Resource and Transmission Assessment Criteria [27].

As far as international standards are concerned, IEC 61000-4-2,3,4,15 and IEC 61000-3-6,7 have been adopted and some DNOs implement the IEEE 1547 Standard [25].

Further down, the policy that is applied by each DNO in Canada is presented.

### ATCO Electric

ATCO Electric maintains the steadystate voltage within the following limits as stipulated in CSA Standard CAN3 C235. The following Table 3 is extracted from this standard [19], [20], [26], [28].

**Table 3: Steadystate voltage limits (Canada - Atco Electric)**

| Type | Low *SUPE99* 99.9% | *SUPE95* 95% | Declared $V_d$ | *SOPE95* 95% | *SOPE99* 99.9% |
|---|---|---|---|---|---|
| Single phase | 106 | 110 | 120 | 125 | 127 |
| | 212 | 220 | 240 | 250 | 254 |
| | 424 | 440 | 480 | 500 | 508 |
| | 530 | 550 | 600 | 625 | 635 |
| Three phase 4 Conductor | 110/190 | 112/194 | 120/208 | 125/216 | 127/220 |
| | 220/380 | 224/194 | 240/416 | 250/432 | 254/440 |
| | 245/424 | 254/440 | 277/480 | 288/500 | 293/508 |
| | 306/530 | 318/550 | 347/600 | 360/625 | 367/635 |
| Three Phase 3 conductor | 212 | 220 | 240 | 250 | 254 |
| | 424 | 440 | 480 | 500 | 508 |
| | 530 | 550 | 600 | 625 | 635 |
| % 10minute | **-11.7** | **-8.3** | - | **+4.2** | **+5.5** |
| % 3 seconds | **-17.5** | **-12.5** | - | **+6.3** | **+8.8** |

Table 3 states that 99.9% of the time the utility voltage will not drop below SUPE99 and that 95% of the time, it will not drop below SUPE95. Similarly for voltage rise [28].

### Energie NB POWER

Energie NB Power determines the maximum capacity for DER based on assessment of the following [19]:

- Area load: Maximum allowable generation will be equal to a portion of the feeder or substation annual minimum load (typically 50%-100%) depending on the type of generation and the sophistication of the protection system.
- The ability to properly regulate voltage along the entire length of the feeder: This includes observing the “Recommended Voltage Variation Limits” of CSA Standard CAN3 C235-83 - “Preferred Voltage Levels for AC Systems 0 to 50,000V” during both steady state operation and temporary voltage sags that occurs when the DER trips. Customers on the feeder shall not be subjected to severe voltage sag following a DER trip. Therefore, sudden loss of a DER while at full load shall not cause the primary voltage to sag below 0.95pu.
- The ability to protect and coordinate for all fault types and abnormal system conditions.
- Distribution system losses: DER shall not increase distribution system electrical losses. Locating distributed generation very near the substation will produce a negligible effect on losses while exporting large amounts of power back toward the substation from the remote end of the feeder may result in increased losses.
- Whether or not export from the Distribution system to the Transmission system will be permitted. Such permission will be on a case-by-case basis.

### Hydro One Inc.

The capacity for all sections of all feeders (feeder limitation) is based mainly on the distance from the Hydro One Networks Inc (HONI) supply station to the DER‘s Point of Common Coupling (PCC). The feeder limitation applies to all DER connected or connecting to the feeder and considers the rated output capacity of each DER. Any single

DER connection can affect the capacity available for all sections of the feeder. For all sections of the feeder, the total current shall not exceed [25]:

- 400 Amps for HONI feeders operating at voltages 13kV or greater.
- 200 Amps for HONI feeders operating at voltages below 13kV.

The acceptable individual generation limits for three-phase DER facilities interconnecting to HONI Distribution System feeders shall not exceed [25]:

- 1 MW per connection on feeders operating below 13kV.
- 5 MW per connection on 27.6kV feeders supplied via a 44/27.6kV step-down transformer.

The feeder limitation determines the total acceptable three-phase generation allowed for all sections of HONI`s Distribution System feeders and shall not exceed [25]:

- 30 MW for feeders operating at 44kV.
- 19 MW for feeders operating at 27.6kV.
- 9.6 MW for feeders operating at 13.8kV.
- 4.3 MW for feeders operating at 12.48kV.
- 2.9 MW for feeders operating at 8.32kV.
- 1.45 MW for feeders operating at 4.16kV.

The Short-Circuit limits at TS[2] low voltage bus or at any portion of distribution feeder shall not be exceeded by the addition of DER. Maximum fault levels must be maintained within the limits set by the Transmission System Code (TSC) and the interconnection of DER facilities shall not cause these limits (see the following Table 4) to be exceeded [25].

**Table 4: Maximum fault level limits (Canada - Hydro One Inc.)** [25]

| **Fault Levels** | **Requirement** | | |
|---|---|---|---|
| Maximum fault values are symmetrical fault values.<br><br>Higher values may exist for short times during switching | Nominal Voltage (kV) | Maximum Three-Phase Fault (kA) | Maximum SLG Fault (kA) |
| | 44 | 20 | 19<br>(usually limited to 8 kA) |
| | 27.6 (4-wire) | 17 | 12 |
| | 27.6 (3-wire) | 17 | 0.45 |
| | 13.8 | 21 | 10 |

Hydro One has adopted a policy intending to:

- manage reactive power flow, therefore to manage both pre-and post-contingency voltages.
- limit short-term voltage fluctuation (avoid customer complaints).
- prevent excessive operation of voltage regulating facilities.

Based on the above purposes, Hydro One according to [25], [29] has set 5 criteria that have to be met so that there are no problems related to voltage issues:

**Criterion 1** - The DG shall not actively regulate the voltage at the PCC [25], [29]. DG active voltage regulation means that the DG will continuously monitor the feeder voltage and respond to it by automatically adjusting its reactive power to control the feeder voltage within a desired range. This may result in causing a) unacceptable post-contingency voltage if DG trips or b) aggravate voltage fluctuation at other points of the feeder [29] leading voltage at the PCC out of the acceptable limits [25].

For instance, let’s consider that there is the following network in order to justify the a) case [29]:

[2] Transmission Station.

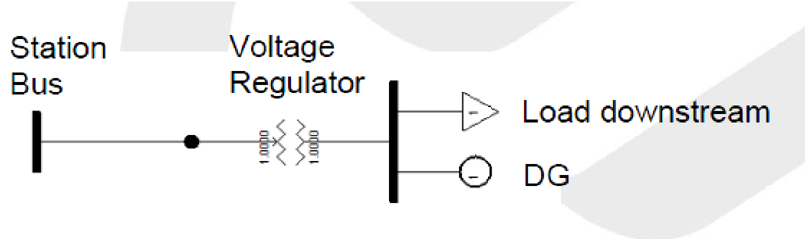



**Fig. 3 Network in which unacceptable post-contigency voltage may occur** [29]

If the voltage is controlled actively by the DG, the load voltage is controlled by the DG and the voltage regulator does not respond to load directly. Taking into account this, in case that DG trips, the load voltage is uncontrolled immediately after the tripping for some minutes [29].

For instance, let's consider that there is the following network in order to justify the b) case [29]:

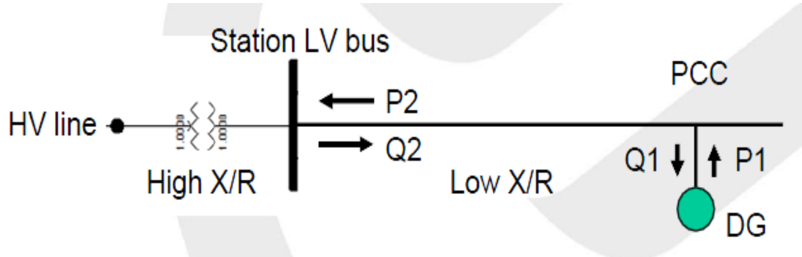



**Fig. 4 Network in which high aggravation of voltage fluctuation may occur** [29]

If the voltage is controlled actively by the DG, DG aggressively varies Q1 so as to control PCC voltage as P1 is fluctuating. As a result Q2 fluctuation at the LV bus is aggravated. If we take into consideration that the upstream network is characterized as a high X/R one, we realize that the voltage at the LV bus fluctuates more since this point is very sensitive to Q2 fluctuation [29].

**Criterion 2** - PCC voltage shall be maintained within 0.94~1.06 p.u. and shall not be lower than pre-connection voltage. Hydro One station LV bus voltages are regulated within 1.035~1.055 p.u. regardless of load levels. This ensures that the voltage anywhere in the feeder, including the PCC, is within 0.94~1.06 p.u. of the nominal voltage under normal operating conditions. To conform to the existing practice, DG shall not decrease the pre-connection PCC voltages under all normal operating conditions. Even if primary feeder voltages are well above 0.94 p.u. voltages of feeder circuits, supplied by step-down transformers (off load tap changers), voltage may well be approaching 0.94 p.u. [29].

**Criterion 3** - At the feeder level, DG shall not contribute to short-term voltage fluctuation anywhere on the feeder by more than 1%. Without DG, the short-term voltage fluctuation on Hydro One feeders is well below 1%. Hydro One has received complaints of short-term voltage fluctuation due to DG. The dead-band of existing Hydro One voltage regulating facilities is about 2%[3]. Half of the dead-band is chosen as limiting value, to mitigate the risk of frequent operation of voltage regulating facilities [25], [29]. DG that violate this criterion, typically absorb more reactive power per MW as compared to the DG that comply with this criterion[4] [29]. The short-term voltage fluctuation is defined as the voltage change that can be caused in a few minutes by an output power fluctuation of 30% and 60% of the nominal power of wind and solar power plants respectively (Hydro One definition) [30]. The following graph shows how short-term voltage fluctuation is defined [31].

[3] In this way the voltage at LV busbars of the voltage regulators remains within 0,94~1,06 p.u.
[4] See the example that is given further down.

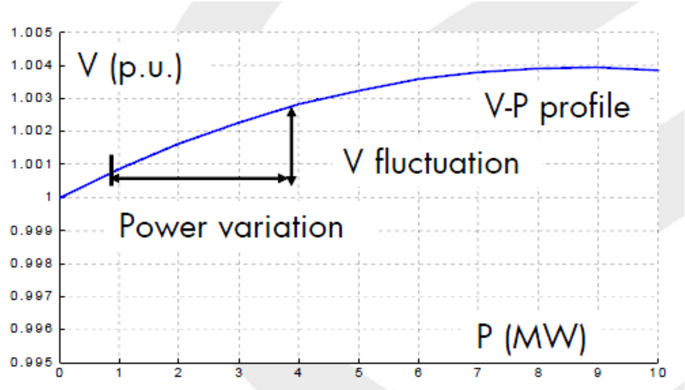



**Fig. 5 Short-term voltage fluctuation according to Hydro One Inc. definition** [31]

Moreover, it is strongly dependent on the power factor of the DG as the next graph shows [30].

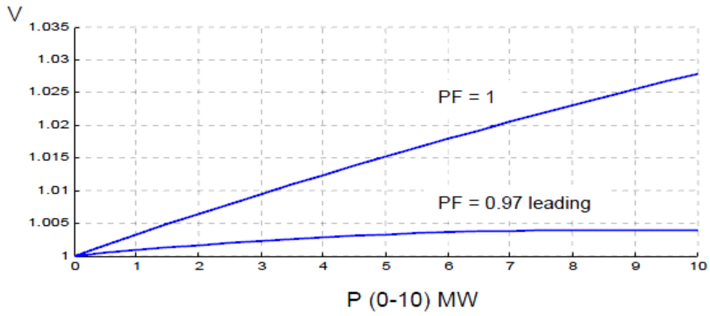



**Fig. 6 Voltage variation of PCC depending on power factor of DG** [30]

However, reactive power consumption attributed to DG is limited by the post-contingency voltage performance requirement (see Criterion 5).

**Criterion 4** - Similarly, there is a rule according to which at the station level, all DER connected to the TS/DS shall not collectively contribute to short term voltage fluctuation at the station LV bus by more than 1% [32].

**Criterion 5** - Tripping of all DGs connected to the station shall not cause abrupt voltage change to result in a voltage above 110% of nominal bus voltage, or less than 90% of nominal bus voltage, after a single contingency and before the station OLTC/feeder VR operates (post-contingency voltage requirement criteria). Thus, it is imperative that net change in reactive power consumption from the system due to DG tripping should be minimized to prevent excessive voltage change before regulating facilities can react [25], [27], [29].

Taking into account the above mentioned criteria, there appears a controversy between them. Meeting some of them results in limiting the capacity of the substation and the feeders and vice versa. In more detail, increasing the feeder DG capacity, addressing the violation of the feeder voltage criteria, decreases the station DG capacity (feeder vs station capacity). So, if we want to increase the DG size at a given location, the reactive power consumption attributed to the DG on per-MW basis has to increase so as the 2nd and the 3rd criteria to be met. However, at the station level, the total reactive power consumption attributed to DGs has to be limited so as the 1st, the 4th and the 5th criteria to be met [31].

The more reactive power individual DGs absorb under light-load conditions, the less DG capacity a station can accommodate. As a rule of thumb, the total reactive power consumption attributed to DGs on a feeder should not exceed one-third of the DG real power output under light-load conditions in order to avoid severely limiting the station DG capacity [30]. In a pessimistic scenario, if all DGs just barely meet the rule of thumb, a station may just be able to accommodate DG up to 12% of the station short-circuit MVA (from the view point of voltage regulation)

[30]. In an optimistic scenario, if all DG are very close to the station and are able to maintain PCC power factor at unity, there is practically no limitation from the view point of voltage regulation [30].

Where reverse power flow is possible, all existing voltage regulating and metering devices shall be made suitable for bi-directional flow. The distribution system was designed to operate for unidirectional power flow (flowing from the substation to the customers). Voltage regulating devices[5] were designed to correctly operate under these conditions. However, with the addition of DG into the system, the power flow can be reversed when the DG is supplying power. This may inhibit the voltage regulators to properly regulate the voltage on the feeder. If there is a possibility of reverse power flow, regulating devices (line voltage regulators, regulating stations and transformer under-load tap changers at the Transformer Station (TS) or Distribution Station (DS)) on HONI's distribution system may need to be either upgraded or replaced with suitable devices that allow bi-directional flow [25].

From the above described criteria, we realize that there are factors that play significant role in determining whether a power plant can be connected or not, such as the X/R ratio, the previously allocated power plants, the voltage level of the feeder etc.

A case study, which explains how the above mentioned 5 criteria are applied, is presented in Annex B.1

As far as micro and small generation[6] is concerned, the following simplified rules are applied [26]:

- In order for the voltage at the service entrance to remain within the limits under all system operating conditions, the total connected generator capacity shall not cause the voltage rise on the secondary service conductor to exceed 1% of operating voltage. To meet this requirement, re-conductoring of the service drop may be required.
- For transformers rated 50 kVA or higher, the total connected generation capacity, including the proposed generation, must be limited to the nameplate kVA rating of the respective transformer winding. To meet this requirement, the transformer may need to be replaced with one of higher rating (e.g. for a 50 kVA transformer, the maximum permissible generator rating is 50 kW at unity power factor).
- Transformers rated less than 50 kVA (typically 10 kVA and 25 kVA) have higher winding resistance. For these, the total connected generation capacity including the proposed generation must be limited to 50% of the nameplate kVA rating of the respective transformer winding. To meet this requirement, the transformer may need to be replaced with one of higher rating.
- For generators connected between line-to-neutral terminals of the transformer secondary, the total connected generation capacity shall not exceed 25% of the transformer nameplate kVA rating. To meet this requirement, the transformer may need to be replaced with one of higher rating.
- The total generation to be interconnected to a distribution system circuit line section, including the proposed generator, will not exceed 7% of the annual line section peak load[7].
- The total interconnected generation, including the proposed generator, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts and line re-closers) or customer equipment on the system, to exceed 100% of the short circuit interrupting capability. To meet this requirement, protective devices may need to be upgraded.

The following figure shows the above mentioned rules [33].

[5] HONI operates all voltage regulating devices on its distribution system to 125V ±1.5V on a 120V base [25].
[6] Less than 30 kW.
[7] See Note on page 70

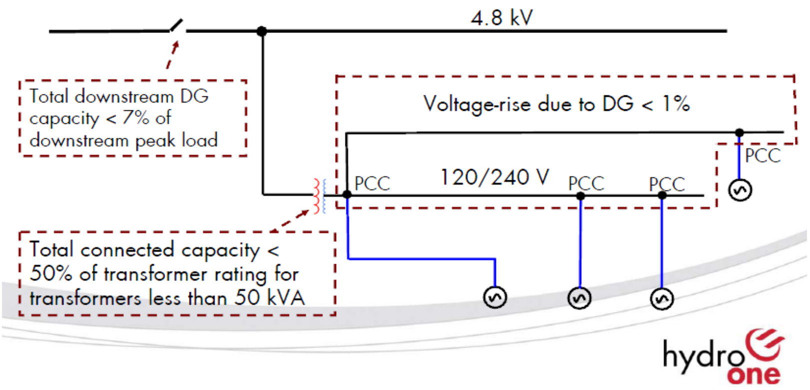



**Fig. 7 DER hosting capacity rules in LV networks (Canada - Hydro One Inc.)** [33]

Hydro One applies two criteria (Thermal Capacity and Short Circuit Capacity) to determine the capacity of a HV/MV substation.

The Thermal Capacity represents the estimated name plate amount of generation that can be added to that bus or station mainly based on the reverse flow limits of the transformer according to the following rule: Reverse power flow must not exceed 60% of station capacity (sum of 60% maximum MVA rating of the single transformer and the minimum station load [25] to protect the system in a situation where 1 transformer is out of service [25], [34]. This depends on the following two criteria [35]:

- Dual secondary winding transformer capacity: Based on information from transformer manufacturers, Hydro One has determined that some dual secondary winding transformers cannot withstand forward flow in one secondary winding while there is reverse flow in the other secondary winding. Excessive imbalance between the two secondary windings causes overheating and potential failure of the transformer.

- Minimum Load.

The minimum load station is actually included in the thermal capacity number as described above. So it is only informative [36].

The Short Circuit Capacity represents the maximum amount of short circuit contribution that a generator can add to a station bus before short circuit limits are exceeded as shown on the following Fig. 8 [35].

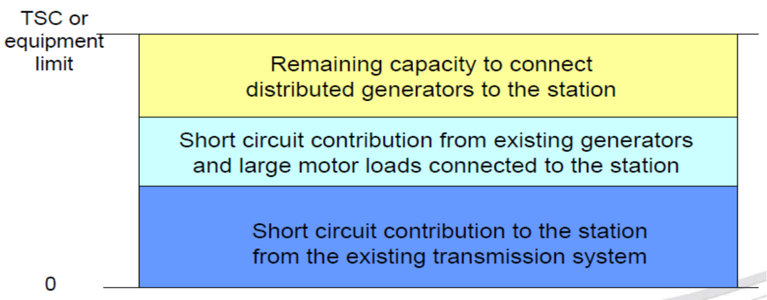



**Fig. 8 Impact of DER on short-circuit levels (short-circuit capacity)** [35]

A case study, which shows the determination of the capacity of the substation and how one may calculate the remaining capacity for DER connection is presented in Annex B.2

**Nova Scotia**

When an application is submitted, the DNO has to conduct a Preliminary Assessment study. The Preliminary Assessment is a high level review of system thermal limits, power quality issues (flicker/voltage levels), peak and minimum load levels, available fault levels, existing generation and other Interconnection Requests in the area. The Preliminary Assessment also provides an order-of-magnitude cost estimate of required system additions and upgrades to accommodate the Generating Facility [37].

**Hydro Ottawa**

Hydro Ottawa performs an impact assessment of the proposed generation facility on the distribution system and customers, including [24]:

- Voltage impacts.
- Current loading.
- Fault currents.
- Connection feasibility and identification of line/equipment upgrades required, distribution or transmission system protection modifications/requirements, and metering requirements.

## China

The existing domestic series of standards for grid-connected DG, mostly applied to DG (i.e. synchronous/induction generators, DG supplied with inverters, etc.) connected to the distribution network up to 35kV, including wind, solar, biomass, hydroenergy, tidal energy, ocean energy and other RES and waste heat, residual pressure and exhaust gas power generation and combined cooling heating and power and so on.

In China, the basic principles, that the standards of DER interconnection are based on, are:

- The installation of DER should not pose any problems to the other users of the network.
- The installation of DER should not affect adversely the coordination of the protection relays.
- The installation of DER should not reduce the reliability of the grid or not affect the security and stability of the network.

The standards of DER interconnection to the network focus on:

- Connected capacity.
- Connected voltage level.
- Power quality.
- Power control and voltage regulation.
- Communications and information, energy metering and the corresponding technical requirements and network detection.
- Voltage/current/frequency response, safety, protection and automatic safety devices.

**Connected capacity**

In a geographic region, the proportion of the total installed capacity of DG and the load of the region is limited within a not too high certain range. The ratio is usually based on the capacity of the transformer, the thermal stability of the cable line limit, the short-circuit capacity of the switch and the grid connection.

According to the technical rule for the DG interconnection to the network, in case there are more than one power plant, that are to be connected to the common connection point, there should be an overall consideration of their impact. As a principle, DER connection to 110kV or lower voltage level should generate power that has to be consumed in the corresponding grid. When a certain capacity of (intermittent or non-intermittent) DER is connected to the distribution network, the number of transformers and the overall capacity of a substation, which is reserved for the DG, should be taken into consideration and consequently well designed, usually meeting the following three conditions:

a. Provide adequate margin for DER.
b. Meet N-1 criterion.
c. Connection of reasonable load to the substation

In order to meet the conditions b) and c), the equivalent load conditions of 110kV~35kV substations should be consided as follows ( where $Load_{min}$ and $DG_{min}$ could be taken as zero):

- $Load_{max} = Load_{max} – DG_{min}$
- $Load = Load_{max} – DG_{max}$
- $Load = Load_{min} – DG_{min}$
- $Load_{min} = Load_{min} – DG_{max}$

A case study is presented in Annex C.

In fact, taking the uni-directional power flow into account, the maximum DG ($DG_{max}$ ) at any time within the region could be curtailed by protection setting when $DG_{max}$ is greater than the capacity of transformers in the connected substations.

As for the voltage level of the network, that the DER should be connected to, has to be determined applying the following rules:

- DER with nominal power of 8kW and below should be connected to the 220V network,
- DER with nominal power of 8kW~400kW and below should be connected to the 380V network,
- DER with nominal power of more than 400kW~6000 kW should be connected to the 10kV (6kV) or higher voltage level network.

**Short-circuit capacity**

The short-circuit issue is considered to affect in two ways the interconnection of DER to the network. Firstly, as it is obvious DER increase the total short-circuit current contributing to this. Secondly, the DER affect adversely the power quality when the PCC short-circuit current and DER rated current ratio is relatively low.

As far as the first issue is concerned, the following picture shows a case where there is a fault in a feeder. In this case, the total short-circuit current in a breaker consists of a short-circuit current of the upstream grid and another one caused by the DER. In order to ensure the safe operation of the distribution network, the total short-circuit current (including the DER contribution) should not be higher than the allowable value of short-circuit current. Otherwise, the network must be supplied with current limiting devices.

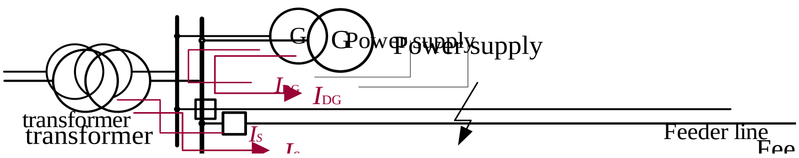



**Fig. 9 Diagram that shows the impact of DER on short-circuit current**

Regarding the second issue, due to the big impact on PCC, that the power supply fluctuation during the connection of DER has, PCC is considered as the assessment reference point for voltage variation. Typical schematic diagram of DER connection to the network is shown below:

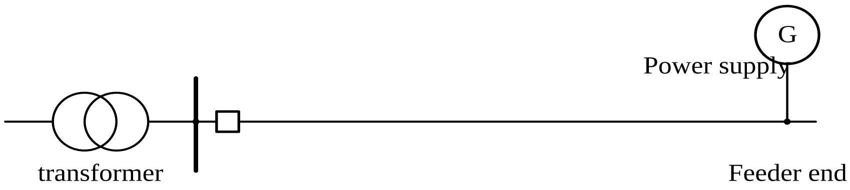



**Fig. 10 Schematic diagram of DER integration to grid**

Regarding the second issue, due to the big impact on PCC, that the power supply fluctuation during the connection of DER has, PCC is considered as the assessment reference point for voltage variation. Depending on four extreme cases, the following diagram shows the voltage variation of each node when DER is disconnected and connected to the substation bus, to the middle of the feeder and to the terminal node of line. In this diagram, DER connected to the grid affects the voltage of the PCC most, and the closer the PCC is to the end of the feeder, the more voltage increase occurs in PCC and in other close to PCC nodes.

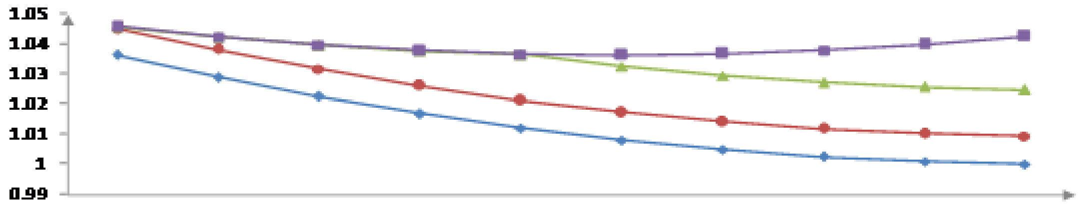



**Fig. 11 Voltage variation along a feeder in several load-generation cases**

Note 1: The horizontal axis is the line length while the vertical axis is the voltage. The figure curves are: ① (blue) no DER connection, ②(red) DER connected to busbars of the substation, ③(green) DER connected to the middle of the line, ④(purple) DER connected to the end of the line.
Note 2: Boundary conditions: line is lightly loaded and the voltage of line is 1.0 p.u.

Based on the equivalent by Thevenin circuit of the network and some simplifications, the maximum voltage ratio $d_{max}$, that appears during the connection of DER to the network is:

$$d_{\max} = \frac{S_{DG}\cos(\phi+\theta)}{S_S}\times 100\% = \frac{I_{DG}\cos(\phi+\theta)}{I_S}\times 100\% \quad (1)$$

where:
$I_{DG}$ is the rated current of DER,
$I_s$ is the system short-circuit current at PCC.

As it is well known, different types of DER may have different power factors. For instance, the power factor of a power plant which is supplied with converter could reach 1, while the power factor of DER that has rotating generators usually lies from 0.8 to 0.9. Taking into consideration the equivalent impedance angle φ, the value of cos(θ+φ) should be about 0.7. According to national standard GB/T 12325 «Power Supply Quality - Allowable Deviation of Power Supply Voltage», the voltage deviation of 10kV and below networks should be less than the 7% of the nominal voltage. Replacing these two values to the previously mentioned equation, the PCC short-circuit current and DER rated current ratio should not be less than 10. In this way, the power quality of the network is maintained in acceptable levels and the voltage requirements are met also.

$$\frac{I_S}{I_{DG}} \geq \frac{\cos(\phi+\theta)}{7\%} = \frac{0.7}{7\%} = 10 \quad (2)$$

**Power quality**

1. Harmonic distortion

Harmonic current components, that the DER inject to the network (root-mean-square value) at PCC, should not exceed the permissible values. Besides, the harmonic permissible injection by DER to grid should be distributed according to the ratio of power protocol capacity to the capacity of power generating/supplying equipment.

2. Slow voltage variations
   - The sum of the absolute value of the positive and negative voltage deviation of 35kV PCC should not exceed 10% of the nominal voltage (note: if the upper and lower deviations are of the same symbol (negative or positive), then select the larger absolute value as the measure basis).
   - The voltage deviation in 20kV and below networks should lie within ±7% of the nominal voltage at PCC (three phase DER).
   - The voltage deviation in 220V networks should not exceed +7% and -10% of the nominal voltage at PCC (single phase DER).

3. Voltage fluctuation (rapid voltage changes)

The voltage fluctuation limits at PCC, caused by DER only, are related to the frequency of voltage changes and the voltage grade.

4. Flicker

The flicker at PCC caused by DER alone should be assessed using three levels according to the proportion of power installation capacity of DG and the system voltage grade.

5. Voltage unbalance

With DER integration to the network, the unbalance degree of three-phase voltage at PCC should not exceed 2% and 4% in a short period of time; unbalance degree of three-phase voltage at PCC caused by DG should not exceed 1.3 % and 2.6% in a short period of time.

6. DC component

When DER are connected to the network through converters, the DC current component should not exceed 0.5 percent of its AC definite value at rated state.

**Power factor**

With regards to active and reactive power control, the technical standard requires that the DER, connected to 10kV (6kV) and above network, take part in the operation of electric network in order to ensure the stability of the power systems in cases of fault or special operation mode.

Due to the small nominal power of DER connected to 380V network, the power control has limited benefit for the network. Taking into consideration the cost and the technical factors, the power factor have to be kept between 0.98(lead) and 0.98(lag).

Due to the different adjusting ability and mode for synchronous, induction and converter type DER, different requirements are set respectively. The limits of power factor are established with regard to the adjusting ability of DER.

The voltage control of DER connected to 10kV (6kV) network should be applied according to the following rules:

- DER that have synchronous generators should have a continuously adjustable power factor between 0.95(lead) and 0.95(lag). DER should also participate in the voltage control of PCC.
- DER that have induction generators should have a continuously adjustable generator power factor beween 0.98(lead) and 0.98(lag). If there are some special requirements, the power factor should be adjusted properly so as to stabilize the voltage.

- DER that are equipped with converter should have a continuously adjustable power factor between 0.98(lead) and 0.98(lag). If there are some special requirements, the power factor should be adjusted properly so as to stabilize the voltage. The reactive power control should also be applied so as to control the voltage at PCC.

**Islanding and bi-direction operation**

As for islanding operation and bi-directional operation, some countermeasures have been used. Cut-down equipment should be applied whenever islanding operation happen, and generation curtailment is allowed when bi-directional operation happen.

**Summary**

Based on the analysis mentioned above, the design of distribution network for hosting DER is similar to the philosophy for hosting regular load in distribution system because of the Inherent nature of distribution system no matter uni-directional or bi-directional operation. The maximum capacity for hosting DER is determined by such a rule: firstly, the maximum capacity is determined by thermal rating of the network, the connected voltage level and the available CCP, then the maximum capacity is decreased by the requirements from short circuit levels, voltage regulations and power quality, finally and effect on others (signaling, the existing protection setting, islanding operation and generation curtailment) will decrease the maximum capacity of DER further. However, in the case of sufficient control and management tools applied, the maximum capacity of DER would be able to be increased.

## Czech

In Czech Republic, the technical guideline according to which the DNO makes the interconnection feasibility study and outlines the criteria that have to be met is included in the Rules of the Distribution System Operation (Grid Code, RDSO).

In the last few years, Czech Republic has experienced a major uncoordinated expansion of DER (especially RES). The obligation to primarily purchase electricity generated in RES (by the Act on Promotion of Use of Renewable Sources No. 180/2005 Coll.), although these sources are not held responsible for their generation (or a lack thereof), brings about non-standard operational situations in the Czech power system. The most important technical rules which govern the judgment of an application for connection of a new power source to Czech distribution grids (low-voltage / LV, high-voltage / HV and 110 kV levels), are described here below. The focus is on newly added rules resulting from practical situations and the present uncoordinated development of distributed sources.

All sources to be newly connected to a distribution system must meet the criteria contained in the Grid Code (RDSO) for the low-voltage (LV), high-voltage (HV) or 110 kV level. The intention of these rules is to guarantee a secure and reliable parallel operation of all sources**.** The most important steps in the connection process include the following activities:

a) Evaluation of the application for connection

After receiving the application for the connection of a DER, the DSO will consider the nature of the DER and the point of connection and will make a decision. The decision will be taken with regard to the following factors:

- Available connection capacity at the 110kV/HV substations. The maximum accumulated power that can be connected to the HV network, including both existing and dedicated feeders, derives from the following relation:

$$P_{Max} = (\sum P_{i(N-1)} * k_{tr} + P_{Bilance}) * k_e \quad (3)$$

Where $P_{i(N-1)}$ is the sum of installed rated powers of the 110kV/HV transformers of this specific substation, excluding the rated power of the transformer with maximum nominal power (N – 1 criterion). In case of substations with just a single transformer, only the half of its nominal power (50% $P_i$) is taken into account, provided the DSO does not decide otherwise.

$k_{tr}$ is a reduction coefficient related to the optimum transformer loading (this value is usually set to 0.9).

$P_{Bilance}$ is the power balance of the concerned region that comes from the combination of the minimum load (a value established during the summer measurement usually on July 5 at 13:00 – Czech public holiday) and the maximum generation of all DER that are already connected.

$k_e$ is a reduction coefficient related to the minor DER (usually set to 0.9; if the complete source database is used, then $k_e$ is set to 1). Reduction coefficient $k_e$ allows to set a power reserve for DER, whose connection within the region will be approved even in case of absence of any available transmission capacity (e.g. small rooftop photovoltaic power plants - PVPP).

Also, it will be necessary to verify, that 110 kV lines, under normal operational conditions, will be able to transport the maximum capacity to be connected $P_{Max}$, calculated in the manner specified in the paragraph above (check of 110 kV distribution networks using the N-1 criterion).

- Reserved capacity of the TS/DS delivery point and the value of the limiting (maximum) capacity to be connected from the DSO supply point set by the TSO in the connection contract between the TSO and the DSO. This value is fixed for the relevant TS / 110 kV feed-in node with regard to the reliability of TS/DS transformation (N-1 criterion) and with regard to control capacity of the Czech power system. The determination of the balance value of the reserved connectable output power of pv and wind power plants is based on the simultaneity equal to 0.8, if the contract for connection between the TSO and the DSO concerned does not stipulate otherwise.

  A case study is presented in Annex D.

b) Connectivity study

The subject of the connectivity study regarding a DER is an assessment of anticipated impact, due to the connection of the generator, on the reliability of the operation of the Czech power system (DS and TS). By default, these impacts are analyzed in case of connection of any type (generation or take-off). Most attention is paid to the following parameters:

- Slow voltage variations at the point of connection

  An increase of voltage due to operation of connected DER cannot in the worse case (in the supply point) overpass 2% in case of DER connected to HV (vn) networks and 110 kV networks in comparison with voltage without connection of additional DER. For DER with supply point in LV (nn) the voltage increase cannot overpass 3% [38].

- Rapid voltage variations at the point of connection
  Variations of voltage in the supply point of HV and LV network, which are caused by connecting / disconnecting of individual generators, cannot reach the change of voltage exceeding 2% and 3% in comparison with voltage without connection of additional DER. For DER with supply point in the 110 kV networks it is (in case of normal operation conditions) 0,5% by switching one generator (one wind turbine) or 2% by switching the whole installation (e.g. the whole wind park) [38].

- Harmonics (DER connected to the LV network)

In case that the new connected DER meet the requirements for emission of harmonics currents set by quote ČSN EN 61000-3-12, it is possible to consider harmonic current injection as acceptable. For other cases it is possible to assess currents of higher harmonics ($I_v$) by use following simple kriterium [38]:

$$I_{vnn} = i_v * \frac{S_{kV}}{\sin \psi_{kV}} \quad (4)$$

where $I_{vnn}$ is permissible current

and base current $i_v$ is given in the following Table 5:

**Table 5: Base current $i_v$ per harmonic (Czech)**

| Over tone $v$ | Base current $i_v$ [A/MVA] |
|---|---|
| 3 | 3 |
| 5 | 1,5 |
| 7 | 1 |
| 9 | 0,7 |
| 11 | 0,5 |
| 13 | 0,4 |

$\sin \psi_{kV} = X_k/Z_k$ ($\cong$ 1, if connection point is close to the HV/LV transformer).

A similar methodology can be used for DER connected to high voltage network.

- Flicker.
- Impacts on MRC signals – system for the control of consumption using electrical power networks themselves (a predecessor to smart grids).
- Short-circuit.

Further, the study deals with possible alternative schemes of the connection based on the associated investment costs.

## Denmark

The Transmission System Operator in Denmark, Energinet, is responsible for the grid codes and the technical regulations for connecting various generation resources to the electricity grid and ensuring ancillary services. The distribution system operators are responsible for the quality of operation of the local grids and the grid connection of consumption units. They follow the recommendations and regulations set up by the Danish Utilities Research Institute (DEFU).

As for power quality guidelines for LV and MV distribution grids, the main technical standards applied by the Danish Distribution System Operator are 1) Recommendation 16, “Voltage quality in Low Voltage Grids” [39] and 2) Recommendation 21, “Voltage quality in Medium Voltage Grids” [40]. They are mainly supplemented to the EN 50160 standard and are suitably revised to suit the Danish operating conditions.

Technical guidelines for connecting electricity generation units in supply networks are publicly available at the Energinet.dk website [41] and are categorized as follows:

1. Technical regulation 3.2.1 for electricity-generating facilities of 16 A per phase or lower [42].
2. Technical regulation 3.2.3 for thermal power station units of 1.5 MW or higher [43].

3. Technical regulation 3.2.4 for thermal power station units larger than 11 kW and smaller than 1.5 MW [44].
4. Technical regulation 3.2.5 for wind power plants larger than 11 kW [45].

The technical regulations, TF 3.2.3, TF 3.2.4 are well defined grid codes for synchronous generator used in thermal units and TF 3.2.5 for wind turbine power plants. These grid codes broadly describe the technical requirements the power stations units have to comply with, which include:

1. Tolerance towards frequency, voltage deviations and grid faults.
2. Active power production and frequency control.
3. Reactive power generation and voltage control.
4. System protection.
5. Communication and data exchange.
6. Island operation, Start-up and synchronisation.

The last technical feature is not part of the grid codes relevant to wind power plant stations. Apart from this, the electricity quality limits that have to be fulfilled by wind power plants are explicitly discussed in TF 3.2.5 which is related to voltage fluctuations (rapid voltage changes & flicker) and high-frequency currents and voltages (harmonics, inter-harmonics and disturbances greater than 2 kHz) which are based on IEC TR 61000-3-6, IEC TR 61000-3-7 and IEC 61400-21 standards. Also for the wind power plants, the grid codes are further classified based on the rated power capacity as:

1. Small wind turbines or wind power plants with a power output range of 11 kW to 25 kW.
2. Wind power plants with a power output range of 25 kW to 1.5 MW.
3. Wind power plants with a power output range of 1.5 MW to 25MW.

The above mentioned technical regulations focus more on thermal and wind power plant technologies. Regulation TR. 3.2.1 could be applied for other small decentralised energy resources like the solar PV, storages, electric vehicles with Vehicle-to-grid feature etc. [42]. It is based on the EN 50438 standard [46], “Requirements for the connection of micro-generators in parallel with public low voltage distribution networks” which is suitably adapted to the Danish power system requirements.  The next or another version of TR.3.2.1 grid code may be based on the EN 50549 standards, “Requirements for the connection of generators above 16A per phase to the LV distribution system or the MV distribution system” which could form the basis for units greater than 11kW. TR 3.2.1 specifies the technical and functional requirements that an electricity generation facility with a rated current of 16A per phase or lower has to meet at the point of connection, when connected to the public electricity supply network. For those electrical generation facilities connected to the grid through inverters, the technical regulation specified in VDE-AR-N 4105 [47] standards may be applied for specific services. It is also implied that generation facilities must fulfil the Danish Heavy Current Regulation [48] and the Joint Regulation [49] norms.

The technical requirements and criteria applied by the Danish Operators are summarized in the following Table 6.

**Table 6: Recommendations for voltage quality in Danish LV and MV electricity grids (Denmark)** [39], [40]

| **Recommendations** | **Technical limits** |
|---|---|
| Mains frequency | LV/MV: Measured as a 10-sec average, 50Hz±1% |
| Supply voltage | LV: Measured as a 10-minute average, Un ± 10 %, Un is 230V between phase and neutral<br><br>MV: Un is 10 kV, 15 kV and 20 kV. |
| Rapid voltage changes | LV: Not generally exceed 5% of Un. Up to 10% of Un is acceptable a few times a day<br><br>MV: Not exceed 4% of Un |
| Flicker severity | LV: Plt should not exceed 1 except short periods (few hours per |

| | |
|---|---|
| | week) |
| Voltage dips | Not below 85% of Un<br><br>MV: May not normally occur |
| Supply voltage unbalances | LV/MV: Measured as a 10-minute average, must be less than 2% |
| Harmonic voltage | LV/MV: Effective value measured as 10- minute average should be equal or less than limit ‘Uh’ for 100% of the time as given in the standard harmonic voltage table in EN 50160, THD<8% |

The standard allowable voltage variation is 230 ± 10%. However, the DSO’s practical operational limits are set to 230 + 6%/ - 10% as more household equipments like modern low power loads (eg. light bulbs) are prone to get blown off due to higher voltages above 245V. Such upper voltage limits imposed by the modern loads may be a constraint to the distributed generation units like solar PV, V2G operation during light load conditions. Similarly, on the other hand, some of the modern power electronic loads like induction stoves are sensitive (stop/trip) to the short term voltage dips (seconds). So it is desirable for the voltage to be greater than 0.9pu, even during the dynamic peak loads. Also the non-coincident behavior of a consumer or group of consumers does not reflect the voltage fluctuations or “needle peaks”, when measured on the standard 10-15 sampling rates. To capture the magnitude and behavior of supply deviations on local grid nodes, one to two minute sampling may be required for effective monitoring and control, considering the impacts of future small generation units and loads like that of EV charging with sizeable capacity. The harmonic distortion limits may also exceed on large mix of solar PV and EV units in the local grids. The concurrent switching of the EV inverters on providing regulation services (V2G) may result in the violation of the standard flicker rates of the grid.

## France

In France, the most important technical requirements for the connection of DER to the public distribution network are specified through a ministerial order, a decree and a company guide (3 documents) [15]:

- Government decree n° 2003-229 13 March 2003, which outlines the general technical requirements regarding design and operation that installations need to fulfil for connection to the public distribution network.
- Ministerial order of 17 March 2003, which outlines the technical requirements regarding design and operation, that production installations must fulfil for connection to the public distribution network (with amendments of 22/04/2003 and 27/10/2006).
- Distribution Technical Guide (published by ERDF).

The voltage level at which the DER can be connected to, is determined using the following Table 7.

**Table 7: Maximum power for single DER station per connection voltage level (France)**

| Maximum power delivered to the network | Laws | Connection voltage level |
|---|---|---|
| P < 18 kVA (6 kVA) | Order on 23-04-08 (Distribution Network) | LV single phase |
| P < 250 kVA | | LV three phases |
| 250 kVA < P < 12 MW (17 MW) | | MV |

The connection studies are carried out on a determinist basis (worst case scenario), covering different aspects listed in the regulation (Energy code and several decrees and orders related to DG connection). The design principles of the distribution network need to deal with special attention various items: the voltage planning, the protection plan, the short-circuit withstand strength, disturbances, etc. As a rule of thumb, DER above 3 to 6 MW are usually connected to the HV/MV substation via a dedicated feeder.

**Thermal constraint**

The distribution network operator verifies that the transit capacity of different network devices is not exceeded during the periods of operation of the generation facility and in the different load scenarios. A load flow study based on the actual network characteristics is carried out with the assumptions and data discussed above. The Load Flow software calculates the network studied and highlights all network circuits where current rating overcapacities are identified, and therefore, where network reinforcement and/or creation are required.

**Equipments' short circuit current rating**

The DNO must ensure the short-circuit withstand strength of his materials (equipment and conductors). These studies are performed on a regular basis during the updating of the master plan and changes of load and/or voltage transformer HV/MV and especially when connecting a DER. The studies take into account the intake of short-circuit at the connecting point. The producer can install any device to limit the amount of short-circuit in his installation, before the connecting point. Both in LV and MV networks, the producer has to provide all the required technical data of its installation so that a short circuit study can be conducted based on the IEC 60909. The short circuit contribution plus the existing short circuit must not excess the limits for the HTA and BT network components [50].

**Voltage planning levels**

The calculated voltage rise due to the DER's connection must not cause voltage outside the permitted limits [50], all the more when the feeders have very low loads. Therefore, the DNO must perform voltage planning studies to ensure that, at any point in the network (MV or LV), voltage values lie within the contractual and regulatory voltage range, as an average voltage in low voltage. In LV networks, the admissible voltage range at the output of the DER is ±10% of the nominal voltage (230V/400V). In MV, the admissible range at the output of the DER is ±5% of the contractual voltage, itself set within ±5% of the nominal voltage (nominal voltage usually 20 kV, in some cases 15 kV). Often, the contractual voltage is set at nominal voltage or nominal voltage +1%.

Other rules used for design of connection and potential network reinforcement are:

- if not available, the minimal load on the feeder is considered at 20% of the peak load.
- if not available the tanφ of the consumers on the feeder is considered to be 0.4.
- in LV, a maximum gradient of 2% of the voltage for 1 kW of additional load or generation is allowed at a given point.
- in LV, 1.5% of voltage loss is considered in the connection (between the DER and the connection point on the network).

The MV voltage planning uses the adjustability of the reference voltage at the secondary of the HV/MV transformer. It is based on the voltage profile of MV feeders connected to the same HV/MV transformer. The MV voltage is maintained thanks to tap changers in the HV/MV substation that dynamically adapt their position in a range usually of about [±15%] around the nominal setting.

LV voltage adjustment also uses tap changers of transformers MV/LV. The position of the tap changers can be changed manually with three settings (+0%, +2.5%, +5% against the nominal setting).

DER, connected to MV network and operating in the normal voltage range, shall be able to absorb reactive power of at least 0.35 $P_{max}$ and generate reactive power of at least 0.4 $P_{max}$, where $P_{max}$ is the maximum active power of the generator. Injection of reactive power by DER may be used in MV to limit losses in the feeder. This reactive power injection, which is provided by a fixed tanφ, is usually sized so as to compensate for the reactive consumption of the feeder at its minimum consumption in the year.

**Connection point**

The choice of the connection point is made so as to minimize the overall connection cost while respecting the various technical and regulatory requirements.

**Other items**

Connecting MV generation on MV network creates variations of energy transit into the network, due to the injection of active and reactive power. Furthermore, it may have an impact on transmission network, especially on the protection scheme. Other consecutive issues that have to be dealt by the DSO, are the following ones:

- Protection scheme and decoupling protections.
- Tariff signals disturbances.
- Power quality studies (harmonics, flicker, unbalance).,
- Observability of the generation plant (state, active and reactive power).

For major DER plants (>5MW), FRT (Fault-Ride Through) and frequency response capabilities are required.

The DER connected to the distribution network should not create unacceptable disturbances on the electric system, in particular with regard to:

- Harmonics.
- Flicker.
- Voltage unbalance.
- Supply of short circuit power to the network.

The response of DER installed on distribution network to disturbances or incidents on the electric system (frequency drops or overshoots, short circuits…) must be coordinated between Distribution and Transport Network Operators to avoid the situation where DER would worsen the situation, for instance by disconnecting from the network when they are still needed to support it.

Current situation in France:
These conditions are set by the regulation “Arrêté du 23 avril 2008 relatif aux prescriptions techniques de conception et de fonctionnement pour le raccordement à un réseau public de distribution d'électricité en basse tension ou en moyenne tension d'une installation de production d'énergie électrique”.

**Compliance of the performance of DER through performance control**

The performance of distributed generation connected to the distribution network must be controlled. Indeed, the connection of equipment which does not respect the DNO’s prescriptions is a risk. At a small scale, such situation is not a problem. At a larger scale however, it may become a risk for the stability and the safety of the network. The management of this risk is the key to a large development of DG on distribution networks.

Current situation in France:
A regulation has been issued in 2010 «Arrêté du 6 juillet 2010 précisant les modalités du contrôle des performances des installations de production raccordées aux réseaux publics d'électricité en moyenne tension

(HTA) et en haute tension (HTB)» for DER connection to MV and HV networks, the implementation of which is under way. Basically, 3 types of controls are required:

- controls during the commissioning of the DER.
- controls throughout the life of the DER.
- controls to be carried out after a malfunctioning of the DER.

**Adaptation of the protections of the distribution network and the DER**

- Fault currents
  DER often contribute to fault currents. As a consequence, DER can disturb protection operation on the distribution networks, either by leading the protections to operate when there is no fault or on the contrary preventing their operation when a fault occurs. The DNOs have to adapt the protection scheme of its network accordingly.

  <u>Current situation in France:</u>
  The DNOs make the verifications and modifications potentially necessary on its network during the connection process of a DER.

- Unintentional islanding
  The fast development of DER in distribution networks increases the likelihood of unintentional islanding in areas where the local generation is close to balance local consumption. This unintentional islanding may occur for instance after actuation of protections. In that case, the “island” will find balance with a new frequency and a new voltage, both potentially fluctuating in a more or less stable state, due to load auto-adaptation of loads present in the area.
  Various methods have been proposed and are recommended by national regulations to prevent the occurrence of unintentional islanding, passive and active. However, currently no method has been unanimously validated.
  Passive methods always present the risk of not detecting an islanding situation when the unbalance between local consumption and local generation is too small to have these admissible limits overridden.
  Active methods present severe drawbacks because some are based on the introduction of perturbations, which may become ineffective when many DER are present in same area, while others are based on amplification of existing perturbations of parameters of the network, which may destabilize the network in case of high penetration of DER.
  Other methods are based on communication means between DER and a centralized control (use of power line carrier communications, use of radio, phone or internet communications …). These methods have the economical drawback of being expensive.
  This question of the detection of unintentional islanding is still open and requires further studies.

  <u>Current situation in France:</u>
  The islanding detection is based on overriding threshold of min/max of voltage and frequency in MV and LV as well. In LV, criteria are based on the German norms VDE 126 and VDE 126-1-1 (impedance measurement, oscillating circuit method). In MV network, the decoupling protection (also called “loss of main protection”) sometimes uses remote control through tele-decoupling (called “protection H4”).

**Management of congestions caused on the transportation network by DER connected to the distribution network**

The ability to manage potential congestions on the transmission network is a pre-condition to a high penetration rate of DER on the distribution networks. This is for instance necessary for rural distribution feeders with small consumption and an important amount of connected DER whose production may flow back into the transmission network and therefore create congestions, for instance in case of exceptional situations (N-1).

To avoid these congestions, it is necessary that the TSO be informed of the forecasted and actual power generation of DER on the distribution systems and have the possibility to manage the production of the DER connected to the distribution network when necessary.

Current situation in France:
When a DER requests a connection to the distribution network, if its active power is more than 1 MW, the DNO informs the Transmission Network Operator who evaluates potential impacts on its network. As far as operational control is concerned, a program has been launched to have the wind farms connected to the distribution network monitored by the TSO. Currently more than 80% of French wind farms are monitored. Since end of 2011, a control system, that allow the TSO to shut down in case of N-1 situation power generation connected to the MV distribution network, is being progressively implemented for those power generators that create congestions on the transmission system.

**Regional coordination for development of renewable energy**

ERDF is currently developing regional schemes in accordance with the French TSO, to anticipate the network reinforcements and creations:

- It lists all the works (HV networks – cable/stations- and substations) necessary to connect the Renewable Energy Sources planned in SRCAE (Regional plan of air, climate and energy). It specifies the volumes of DG per family (photovoltaic, wind,…) desired by 2020 and provides a mapping to locate them (favorable areas)
- It gives the estimated cost of these works
- Capacities are reserved for Renewable Energy Sources for a 10 years period

Concerning the funding of the works which are to be created or reinforced, a recently published decree describes the procedure:

- Dedicated assets to their connection charged to the producer
- A specific calculation for each administrative region. Each Renewable Energy Source > 36 kVA in one administrative region will pay the common assets regardless of its location in his region.
- Shared HV assets and substations which are to be created or reinforced (to avoid the following problem: « the first who creates a constraint pays the entire common assets extension »):
    - Creations: financed by the owner and reimbursed by the common assets (paid by the concerned producers)
    - Reinforcements: financed by the owner via the TURPE (tariff for the use of electricity public networks) through TSO and DSO

## Germany

On national level, in Germany two guidelines for connecting DER to the medium and low voltage grids exist:

- BDEW Technical guideline “Generating Plants Connected to the Medium-Voltage Network” as of 2008, applicable to all generators with capacity of 100 kW or higher [51].
- VDE network connection regulation (VDE-AR-N 4105), effective since August 1st, 2011 and mandatory for all generators with installed capacity below 100 kW since January 1st, 2012. It is mainly applicable to low voltage networks but also to plants below 100kW that are connected to medium voltage networks. The core of VDE-AR-N 4105 is network-supporting functionality to guarantee safe and reliable network operation for maximum integration of generating capacity in the low voltage distribution network [52].

Goal of both guidelines is to have DER help to stabilize voltage and to provide reactive power. Another important issue is to enable continuous power reduction of PV systems in case of rising frequency. These guidelines are supposed to be part of individual grid codes of the local or regional DNOs.

The DSO performs short circuit current and load flow calculations on the hosting capacity of his feeders based on the above mentioned guidelines. For medium voltage, the above mentioned BDEW Technical Guideline provides the calculation algorithms as regards network dimensioning, admissible voltage deviations and network disturbances, i.e. sudden voltage changes, long term flicker, harmonics and inter-harmonics, commutation notches and Audio-frequency centralized ripple-control.

In Germany, the hosting capacity at HV/MV substation level is in most cases reached if the voltage band is violated or if the thermal load of any of the assets is too high.

In [51], violation of voltage band is defined as follows: “Under normal operating conditions of the network, the magnitude of the voltage changes caused by all generating plants with a point of connection to a medium-voltage network, must at no junction point within this network exceed a value of 2% as compared to the voltage without generating plants”.

Most calculations so far disregard options to increase hosting capacities of feeders with means of active distribution grids.

In order to increase DER in the grid, more and more DSOs apply grid planning tools such as NEPLAN, SINCAL or PowerFactory to simulate their medium and low voltage grid. This requires a higher initial effort, but allows for quick and more precise grid calculations in case of requirements to connect new generators to the grid. With these planning tools, the DSO can identify bottlenecks as regards thermal loads as well as violations of voltage levels.

The Renewable Energy Act 2012 [53] requires DER with a capacity higher than 30 kW to participate in the feed-in management of the DSO, effective for all generators on January 1st, 2013. In case of grid stability problems of the TSO or the DSO, the DSO must have the option to reduce active power by remote control.

## Greece

In Greece, the basic technical assessment for the connection of DER to the network consists of two guidelines. The first one is the “Guideline for the Connection of PV to the LV Network” and the other one is the “Technical Requirements for the Connection of DER to Distribution Networks, Directive 129”, both issued by PPC S.A., the formerly vertically integrated electric utility of Greece. The first one refers exclusively to PV plants to be connected to the LV networks, while the second one focuses mainly on interconnection of DER at the MV level. Directive 129 provides plenty of case studies including several types of DER interconnection schemes. As far as international standards are concerned, the IEC 61000 series of EMC standards form the basis for the power quality evaluation criteria.

As far as the interconnection of DER to MV network is concerned, the issues dealt with in the interconnection studies include:

- Network capacity (thermal limits of lines, transformers).
- Short circuit contribution (design fault level 250 MVA for MV networks).
- Voltage regulation.
- Power quality (rapid voltage changes, flicker, harmonics, DC current injection).
- Effect on mains signaling.
- Interconnection protection.

Depending on the DER installed capacity, interconnection is in principle possible according to the following Table 8, provided that the imposed technical requirements are also met.

**Table 8: Upper permitted nominal power for single DER based on the interconnection schemes (Greece)**

| Nominal Power (MW) | Interconnection scheme |
|---|---|
| <0.05 | LV network, 1 phase |
| ≤0.1 | LV network, 3 phase, existing or dedicated feeder |
| <5 | MV network, existing feeder (with possible reinforcement) |
| <6 | MV network, dedicated feeder (single circuit 20 kV line) |
| <20 | MV network, dedicated feeder (double circuit 20 kV line) |
| >20 | HV network, dedicated HV/MV substation |

Generally speaking, the interconnection schemes that the DNO applies for connection to the MV and HV network are shown on the next figure [54]. A sixth interconnection scheme is also possible, whereby several DG installations share a new HV/MV substation, connected to it via dedicated MV feeders and operated as private distribution networks.

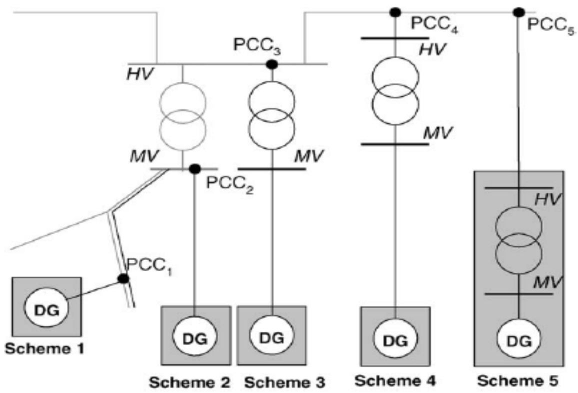



**Fig. 12 Typical DER interconnection schemes at MV level (Greece)**

Regarding voltage regulation in MV networks, there are two criteria:

- The annual median value of the voltage at any node should not deviate more than 5% from the nominal (e.g. 20 kV) [55], a requirement dictated by the regulation range of the off-load tap changers of MV/LV distribution transformers (±5% in steps of 2.5%) [54].
- The voltage variation around the median value should not exceed ±3%, to ensure that the final service voltage to LV users will remain within statutory limits [55].

To evaluate these criteria, load flow studies are performed for the following conditions [55], taking into account the operation of the voltage regulation means of the network:

- Max Load – Min generation
- Max Load – Max generation
- Min Load – Min generation
- Max Load – Max generation

Considered DER include existing and anticipated stations, connected either at the MV or at the LV level (the latter properly aggregated). From the max and min voltages thus calculated for each node, the median and the deviation can be found as [54], [55] as shown in the diagram in Fig. 13.

Median voltage, node i (%)= $\dfrac{\frac{Vmax,i+Vmin,i}{2} - Vnom}{Vnom}$ (5)

Voltage variation, node i (%)= $\dfrac{Vmax,i - Vmin,i}{2 * Vnom}$ (6)

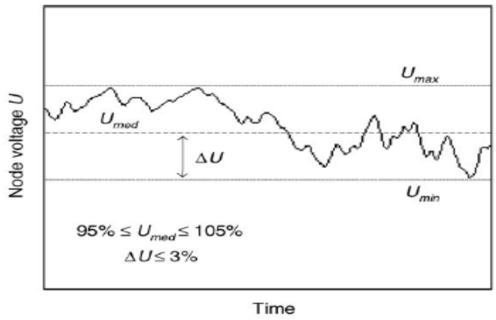



**Fig. 13 Voltage variation due to DER interconnection at a node and steady state voltage variation limits (Greece)**

In case of DER interconnected via dedicated MV feeders to HV/MV substations, an extended voltage deviation limit of ±8% applies [55].

As far as the fault level is concerned, the DNO ensures that the design fault level (250 MVA – 7.5 kA at 20 kV) is not exceeded due to DER interconnection. The short circuit level is usually maximum at the busbars of the HV/MV substations. An upper limit for the DER hosting capacity of a specific network is found if the upstream short circuit contribution is deducted from the design fault level. This margin is then allocated to the DER to be interconnected, regardless of their technology. A higher hosting capacity is thus derived for inverter-interconnected DER, which benefit from reduced short circuit currents. In Annex G.1 a case study is presented. Short circuit calculations are based on the standard IEC 60909.

Another constraint for the installed DER capacity is related with the power factor of the substation, which cannot deteriorate to very low values. According to the Greek Grid Code, HV substations need to operate at a power factor such that annual average lies in the range between 0.95 leading and 0.98 lagging when, the load of the substation is higher than 50%.

Regarding the interconnection of DER to LV network, there is set of technical criteria used by the DNO to evaluate DER interconnection applications. As a general rule, the maximum permitted nominal power of DER to be connected at the LV level is 100 kW. The interconnection study, carried out by the DNO, focuses mainly on thermal rating and voltage regulation issues.

In practice, it is usual that the larger DER installations, with a nominal power near the 100 kW limit, be connected via a dedicated LV feeder. In this way, the DNO reserves a capacity margin for small installations (e.g. roof PV plants up to 10 kW, which receive a special increased FiT), while the voltage rise criterion is more easily met. The maximum aggregate capacity of DER on the same LV feeder cannot exceed 200 kW.

As for the voltage regulation in LV feeders, the main criterion applied is that the voltage rise caused by the aggregate DER capacity should not exceed 3%. This is an easy to apply rule that leads to specific permitted DER capacities, depending of the LV feeder type and distance along the feeder. An example diagram is shown in Fig. 14, drawn for several feeder types and unity DER power factor. In case of DER connected to the MV/LV substation via a dedicated LV feeder, the permitted voltage increase becomes 5%.

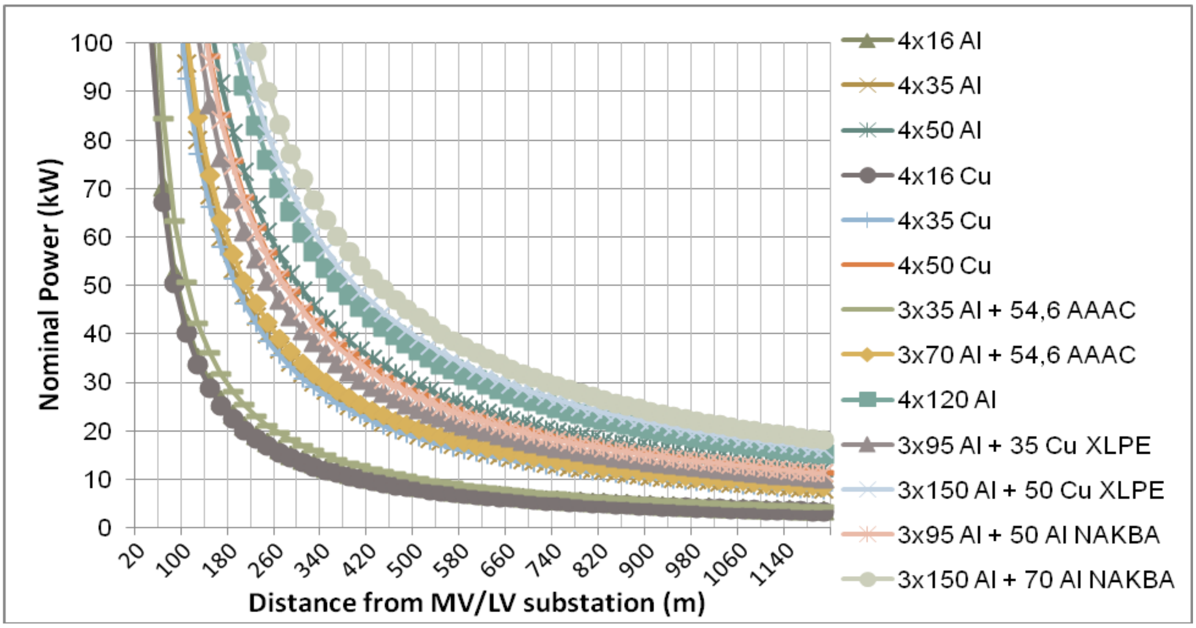



**Fig. 14 Maximum permitted DER capacity for different types of LV feeders, as a function of the connection point distance from the feeder origin (Greece).**

Recently, a new technical guideline for the interconnection of small wind turbines (SWT) was issued. It sets certification requirements, describes criteria and evaluation methodologies to be applied by the DNO and stipulates the acceptable disturbance limits, based on the European standard EN 50438 and the IEC 61000-3 series of standards. A main concern when assessing the interconnection of SWT are rapid voltage changes due to connection and disconnection and flicker emissions. The latter differentiate SWT from other types of DER and are quite difficult to evaluate. Simplified evaluation methodologies are introduced, using graphs to determine the hosting capacity of each specific LV feeder type, as shown in Fig. 15.

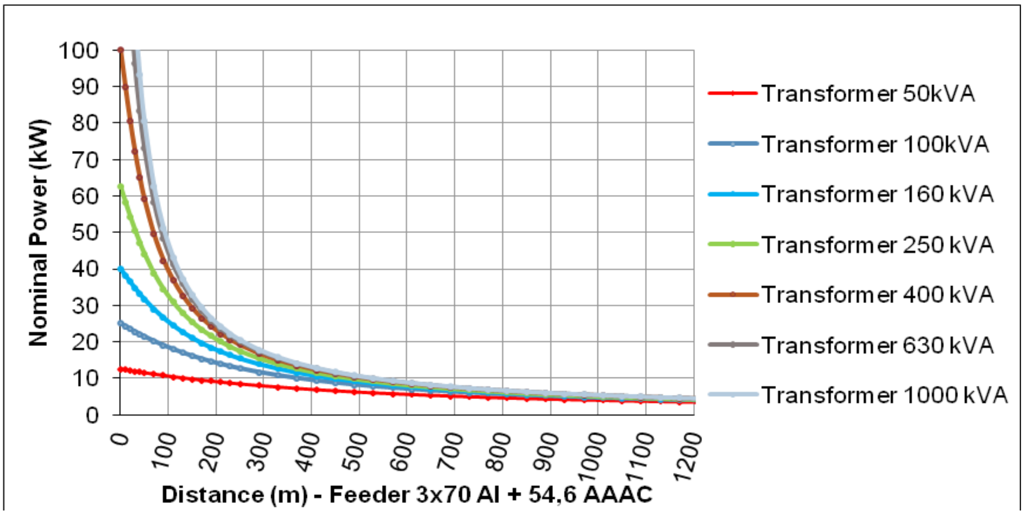



**Fig. 15 Maximum permitted small WT capacity, as a function of the connection point distance from the feeder origin, for different MV/LV transformer capacities (Greece).**

The maximum SWT hosting capacity depending on the rating of the MV/LV transformer is shown in Table 9. It is differentiated according to the configuration of the electrical part of the SWT, which impacts the worse case switching transients at cut in.

**Table 9: Maximum permitted power of small WT (Greece)**

| Transformer nominal power (kVA) | Maximum permitted power of SWT capacity (kW) | | |
|---|---|---|---|
| | SWT equipped with inverter ($k_i$=1.2) | SWT (asynchronous generator with soft-starter) | SWT (asynchronous generator directly coupled to the grid) |
| 50 | 40 | 12 | 6 |
| 100 | 79 | 24 | 12 |
| 160 | 100 | 38 | 19 |
| 250 | - | 59 | 30 |
| 400 | - | 95 | 48 |
| 630 | - | 100 | 75 |
| 1000 | - | - | 100 |

## Ireland

In Ireland, the most important technical requirements, criteria and rules concerning the interconnection of DER to the low, medium or high voltage network is specified in guidelines published or approved by the DNO (ESB), TSO (EirGrid) or CER (Commission for Energy Regulation):

- A Guide to Connecting Renewable and CHP Electrcity Generators to the Electricity Network [2].
- The Distribution System Security and Planning Standards [10].
- Distribution Code [56].
- Criteria for Gate 3 Renewable Generator Connection Offers – Proposed Direction to the System Operators [57].
- Criteria for Gate 3 Renewable Generator Connection Offers – Comments and Response Paper [58].
- Distribution System Operator Licence Granted to ESB Networks LTD.
- ESB National Grid Trasmission Planning Criteria [59].
- Group Processing Approach for Renewable Generator Connection Applications – Connection and Pricing Rules [60].

The DNOs are obliged to conduct network studies to determine the connection method for each DER. DER, that are part of a subgroup, are studied together to determine the optimum connection method for the entire subgroup. The studies analyze how the networks will behave under different loading conditions or in the event of particular faults. Due to the complexity of the networks and the amount of data involved, system studies are invariably carried out using specialized computer software packages known as 'load flow software'. Specific criteria examined include [2]:

- Thermal ratings of equipment.
- Unacceptable voltage rise: The upper permitted voltage rise depends on the voltage level and is shown on the following figures [2], [10].

| Voltage Level | Limit for shared circuit | Limit for a dedicated circuit |
|---|---|---|
| **MV (10/20 kV)** | 1% at point of common coupling of load share, with an additional 2% at generation site | Total of 3% rise at generation site |
| **38 kV** | 1.5% at point of common coupling of load share, with an additional 2% at generation site | Total of 3.5% rise at generation site |

**Fig. 16 Upper permitted voltage rise (Ireland)** [2]

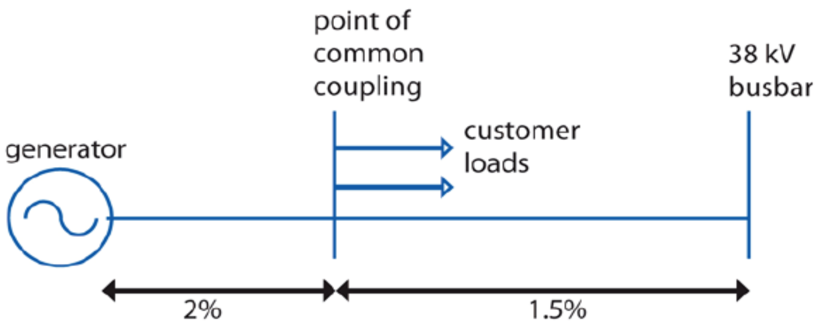



**Fig. 17 Upper permitted voltage rise (Ireland)** [2]

- Fault level limits of existing switchgear: Generally speaking, DER would not be permitted to push maximum fault levels beyond the network design fault levels and/or equipment fault levels which are shown on the following Table 10 [56].

**Table 10: Fault level limits (kA) per connection voltage level (Ireland)** [56]

| Connection Voltage | Short Circuit Level (RMS Symmetrical) Normally | Short Circuit Level (RMS Symmetrical) Certain Designated Areas |
|---|---|---|
| LV (Domestic) | 9.0kA | |
| LV (Ind/Comm) | 37.0kA | |
| 10kV | 12.5kA | 20kA |
| 20kV | 12.5kA | 20kA |
| 38kV | 12.5kA | 20kA |
| 110kV | 26.0kA | 31.5kA |

In some cases, DER may be required to contribute to the cost of new equipment, mainly switchgear to accommodate the increase in fault level associated with the connection of new generation

- Losses limits.
- Voltage stability/dynamic studies.

As well as studying the network under normal operating conditions (that is, with all DER being available), the DNO's engineers will also study the network under a number of contingencies. An example of a transmission contingency case is a single contingency (N-1), which covers the loss of any single item of network equipment or generation at any time [2].

## Italy

In Italy, the technical requirements for connecting DER to the public distribution network are mainly defined in the following two documents [15]:

- CEI 11-20: Requirements for energy generation installations of power higher than 1 kW connected to the LV and MV grids.
- DK 5940: Company requirement (ENEL Distribuzione): Connection requirements to the LV grid for PV installations (powers between 1 and 20 kW).

The nominal power of the DER is the crucial element that dictates the voltage level to which DER is to be connected. The next Table 11 outlines this rule [61].

**Table 11: Upper permitted nominal power for single DER station per connection voltage level (Italy)** [61]

| Nominal Power | Voltage level |
|---|---|
| <100 kW | LV network |
| 100 kW < …… < 200 kW | LV or MV network |
| 200 kW < ….. < 6000 kW | MV network |

In general, in medium voltage network, total installed power cannot make the transformer operate beyond the maximum limits fixed by the DNO for its exploitation (usually 65% of the nominal power) [50], [62]. The equivalent limit for the MV lines is 60% [62]. In low voltage, it cannot exceed the load admitted by the transformer [50].

When the energy produced by DER is higher than the energy consumed by end users connected to the same distribution network, this network should be represented in term of equivalent circuit by an active element (generator). On the basis of measured data, we can notice that in 2007 14% of Enel Distribuzione's primary substations (about 200 substations) worked for some times in the year in reverse energy flow condition (Fig. 18). These conditions are not optimal for a network designed to act as passive, with unidirectional flows. This results in an unavoidable increase of complexity and operation costs. Higher operation complexity, for example in voltage regulation, force studying aimed technical actions (on components, protections, automations, etc.). On higher operation costs, there is a sort of remuneration based on measurement of energy flows made near HV/MV transformers (already available) and MV/LV transformers (available only planning new meter installations) [61].

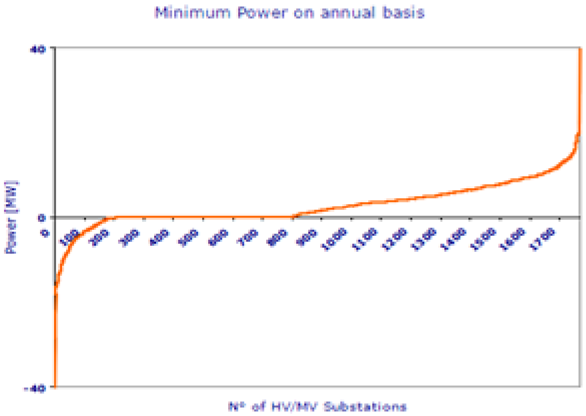



**Fig. 18 Minimum active power (MW) on annual basis of HV/MV substations in Enel network (Italy)** [61]

DER constituted by rotating machines (synchronous or asynchronous) increase short circuit current level in the network [61]. This contribution cannot surpass the short circuit levels compatible with the sizing of the installations or go beyond the switches break and closure capacity [50]. If the only contribution from the HV network is enough to bring short circuit currents very close to component limits, the problem is bigger. If DER are connected to the network through electronic static converter, the amount of DER that can be connected to the same network without building new expensive infrastructure rises [61].

## New Zealand

In New Zealand, each DNO follows its own guidelines in which the Operator outlines the technical requirements, the criteria, the limits and all other issues related to the connection of the DER to the LV, MV and HV network.

A national accepted standard by all DNOs is AS 4777. As far as international standards are concerned, 61000-3 has been adopted.

The connection of DER shall not result in the fault rating of any equipment being exceeded. The normal design fault level on Aurora's[8] 6,6kV, 11kV, 33kV and 66kV networks is 25kA but in certain 11kV and 6.6kV areas there may be equipment with a lower rating (usually dropout fuses with a 13kA rating). The equipment within the DER installation must be capable of withstanding the fault current supplied by the DER and the Aurora network [63].

The DER shall not actively regulate the voltage at the PCC and shall not cause the voltage to other installations on the Aurora's network to go outside the range specified in the Electricity Regulations [63].

## Norway

During the fall of 2010, SINTEF Energy Research performed a survey concerning network planning for distributed generation among 14 DSOs participating in the research project "Optimal infrastructure for seamless Integration of Distributed Generation" (OiDG). One of the purposes of this survey was to understand what kind of problems the Norwegian DSOs were experiencing with the connection of DG in their networks.

None of the responding DSOs pointed out thermal problems. Their main problems are related with voltage and protection and control equipment. The results for those answers can be seen in the following figure.

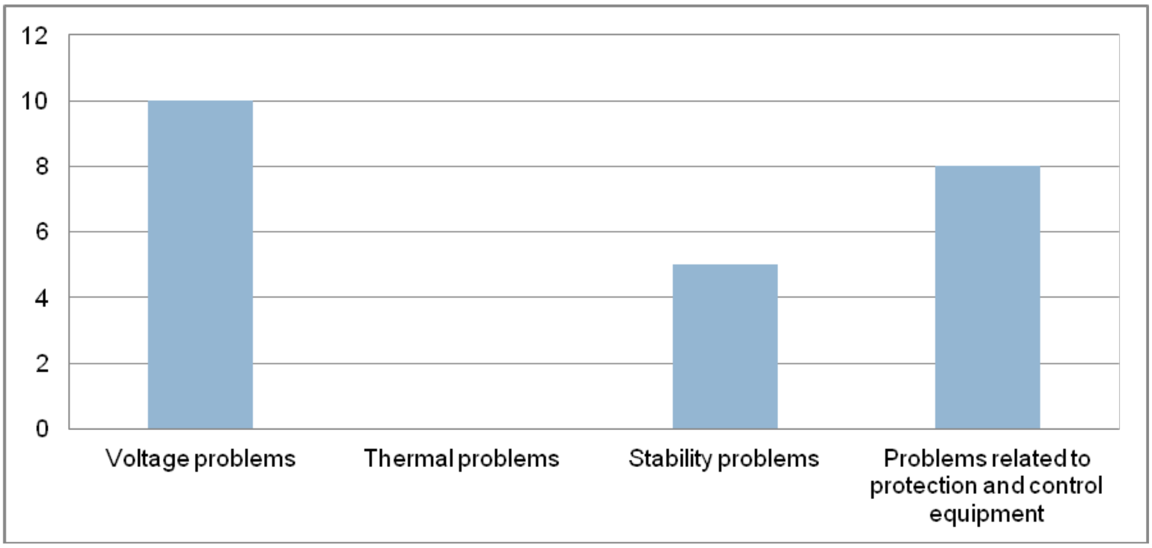



**Fig. 19 Type of problems experienced by Norwegian DSOS due to DER in their networks**

**Voltage problems and voltage regulation**

The answers to the survey show that voltage, protection and control equipment problems are the most common related to distributed generation. The voltage problems illustrate the situation in which, high stationary voltages due to inserted power occur, in weak MV distribution grids, before thermal limits are violated. The DSOs set limits for the lowest and highest allowed stationary voltage at the connection point of DER. The limits may vary between different locations and are dependent on normal variations of both load and generation. This is illustrated in Fig. 20 which shows the upper active power that can be inserted at different distances from the transformer station before the maximum voltage limit is violated.

The highest allowed phase-to-phase voltage may be the limiting factor for the amount of active power which can be inserted at a certain point in the distribution network. The voltage limits set by the DSOs are defined by the Norwegian Power Quality Regulation which is similar to, but somewhat stricter than, the European EN 50160.

[8] Aurora is a DNO in New Zealand

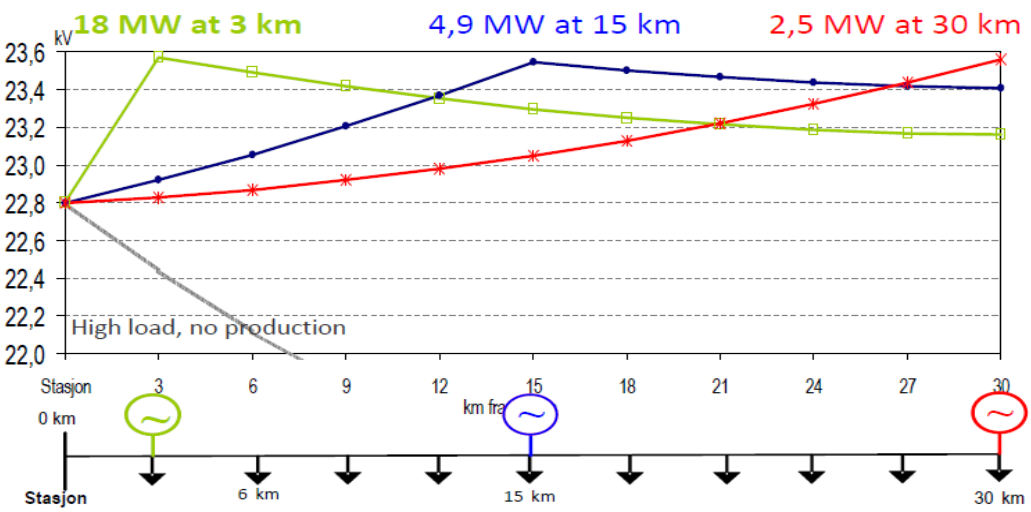



**Fig. 20 Feasible generation levels at different locations**

High stationary voltages are not the only voltage challenges that can be related to distributed generation. Other challenges that might occur include:

- Single rapid voltage changes.
- Harmonic voltage fluctuations.
- Voltage unbalance.
- Flicker.

Some types of generation technologies might lead to rapid voltage variations like flicker or harmonic voltage fluctuations. This is especially the case for DER either characterized by large variations in generated output or connected through power electronics. In Norway, this is mostly relevant for wind power which often connected directly to the transmission network. Unbalanced voltage is an issue mostly related to small one-phase low voltage DG. Such units are not very common in Norway and are therefore not often seen as a factor limiting DG connection.

As opposed to EN 50160, the Norwegian Power Quality Regulation limits the amount of rapid voltage changes allowed in the network. In LV networks, no customers should experience more than 24 rapid voltage changes with a maximum voltage change of more than 5% or stationary voltage change of 3% within 24 hours. Related to DG, this means that all DG units that cause a stationary voltage change of more than 3%, must be given restrictions on how they are connected/disconnected in order to avoid limit violation.

**Protection and control equipment**

DG units contribute to fault currents in MV networks, and therefore Norwegian DSOs are doing relay planning as a part of the network planning process. In some cases the protection unit settings must be modified and in other situations, new equipment is needed. The protection and control equipment problems reported in Fig. 19 are related to inability of installed equipment to work with bidirectional power flows, changes in fault currents, faulty protection unit settings and unintentional islanding.

**Power and energy losses**

The DG resources are often located in sparsely populated areas, with long distances to load centers. And since the distribution networks in such areas are often weak MV networks with limited transfer capacity, new generation usually has a negative impact on network losses. In addition, when large amounts of reactive power are transferred in order to keep feeder voltages below the upper limit, the network losses are further increased.

**Reliability**

If DG units are able to operate in island mode, it could increase the reliability for the feeder customers and reduce the cost of Energy Not Supplied (ENS) for the DSO. This is however not utilized in Norway today and thereby the introduction of DG units reduces the reliability for the other customers on the feeder.

There is no common standard for Norwegian DSOs for network planning with DER. However, looking at the responses from the 2010 survey, all except one of the DSOs use the technical guidelines issued by SINTEF or REN. The guidelines issued by REN are a further development of the technical guidelines issued by SINTEF. These guidelines are therefore closest to a common guideline for DSOs in Norway.

The REN guidelines are issued by REN which is an association of power producers and network operators which promote the debate and sharing of experiences between their associates. They are designed to help the DSOs throughout the process from when the application for network interconnection is submitted to the DNO until the permanent operation permission is given a year after the DG unit is set into operation. The guidelines include specification of needed analyses, limits designed to uphold the Norwegian Power Quality Code and demands for documentation. The limits listed below are taken from the REN guidelines, however all limits are not included in this report.

**Power Quality limits for DG units**

*Voltage band*

No general limits for allowed voltage variations are listed in the guidelines. Each DSO must specify the limits for each DG unit based on load flow calculations. As an example, one DSO sets the maximum voltage limit in the 22 kV network to be +7% from a situation with heavy load and no production. This is however used as a rule-of-thumb basis.

*Rapid Voltage Changes*

The DER unit should not cause a higher number of rapid voltage changes in the connection point than listed in following Table 12. The limits apply for voltage changes with a change in voltage larger than 0.5% of UNom per second.

**Table 12: Limits for rapid voltage changes caused by DER (Norway)**

| Rapid voltage changes | Allowed per 24 hours |
|---|---|
| **ΔUStationary ( 3%)** | 3 |
| **ΔUMax ( 5%)** | 3 |

An exception from this rule applies for DER units that are designed to maintain stability during transient disturbances in the network. If these units are disconnected due to disturbances which are larger than the ones they are designed to ride through, they are allowed to cause a change in voltage of up to 10% in the LV network and 6% in the MV network.

*Flicker*

The DG-unit should not cause flicker intensity (PST and PLT) in the connection point of more than 0.8.

*Harmonic distortion - Voltage*

There are limits that have been set for total voltage harmonic distortion.

*Voltage unbalance*

The DG unit should not cause an unbalance between the phase-to-phase voltages at the connection point greater than 1.8%

*Harmonic distortion – Current*

There are limits that have been set for total current harmonic distortion

*DC currents*

The limit for insertion of DC currents from the DG unit to the grid is set to 20 mA in LV networks or 0.5% of the nominal current (rms) in MV networks.

*DER units*

Several different requirements are set in the REN guidelines regarding the generators of DER units. Some of those are included below.

*Fault ride through capabilities*

Any DG unit with an installed capacity higher than 250 kW which causes a voltage change of more than 4% of UNom in the MV network when disconnected, should have fault ride through capabilities. The dimensioning fault should be a full three-phase short circuit on a neighboring MV feeder as shown in the following Fig. 21.

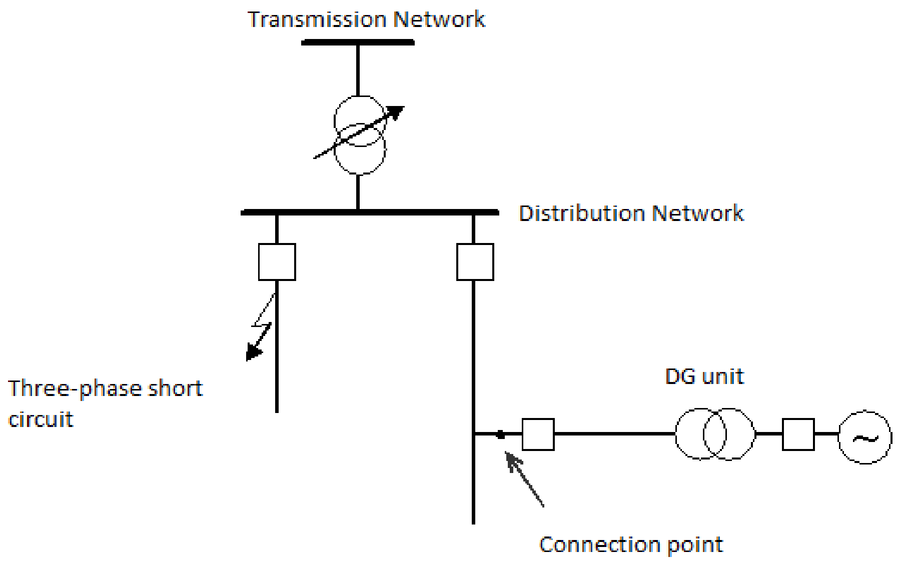



**Fig. 21 Dimensioning fault – Fault ride through capabilities**

*DER with synchronous generators*

Power factor: Due to stability considerations and reactive power reserve in the transmission network, the generator is not allowed to consume more reactive power than tanφ < -0.5.

Voltage regulation demands: All synchronous generators with an installed capacity of more than 1.0 MVA should be equipped with an Active Voltage Regulator (AVR). AVR should be the primary regulating strategy.

Generators with a capacity of more than 5 MVA should have the possibility to install Power System Stabilizers (PSS)

More detailed information regarding demands for the power and voltage regulating capabilities are described in the REN guidelines.

*DER with induction generators*

Power factor: Induction generators should be equipped with phase compensating equipment which at least compensates the no-load reactive power consumption of the generator. Tanφ should be between -0.33 and 0.48 at the DG connection point.

The generator, phase compensating equipment and circuit breakers should be designed in such a way that the possibility for self magnetizing of the generator is reduced to a minimum.

## Portugal

Due to the increase in electric power generation from renewable sources, part of it installed at the distribution level, a new Grid Codes for Transmission and Distribution grids were issued in 2010.

The nominal voltages at the distribution level for High and Medium Voltage are as follows:

- HV Grids: 60 kV
- MV Grids: 10 kV, 15 kV and 30 kV

The amount of DG that can be accepted by the electric system is defined by the TSO, that develops regularly a set of studies on the transmission grid (taking into account security criteria), and defines for each grid area – a set of transmission nearby busses – the capacity that can be connected without any generation restrictions. These studies are updated regularly and tables with the maximum capacity that each grid area can accept are made public, allowing DG promoters to check about the technical viability to develop their projects.

If a promoter envisages installing a DG facility, to be connected to the distribution grid, in an area depending from a transmission bus where there is capacity to receive this new capacity of generation, it should demand to the DSO the following data: point of interconnection, maximum and minimum short circuit levels, nominal voltage and band of voltage regulation. It is responsibility of the DSO to provide this information to the promoter after developing the necessary studies.

When it comes to connecting power generating units to the electrical distribution grid, except wind-generating units, the following conditions should also be met:

- Capacity of each asynchronous generator, when connected to HV and MV distribution grids, should never exceed 5000 kVA.
- Transient voltage drops that may occur due to the connection of asynchronous generators should not exceed 5%.
- Connection of asynchronous generators to the HV and MV distribution grids should occur:
    - After 90% of synchronous speed has been achieved, if the generator’s power does not exceed 500 kVA;
    - After 95% of synchronous speed has been achieved, if the generator’s power exceeds 500 kVA.
- For DG plants connected to the HV and MV distribution grid, it is required to use a transformer with Delta/Star windings, assuring that neutral is never earth connected from the side of the grid.

After a disconnection from the grid, triggered by the interconnection protections due a default on the grid, DG units can only be connected again to the network if the following conditions should be met:

- Three minutes after the service restoration on the grid has taken place;
- The voltage in distribution grid has reached at least 80% of its nominal value.

Additionally, the following conditions should be met when connecting wind power generating units to the HV and MV distribution grids:

Wind power parks with installed capacity above 6 MVA should fulfill the following requirements:

- Be prepared to receive orders from the DSO to open the interconnection circuit breaker, to interrupt their generation;
- Exchange the parameterization of the interconnection protections, using a remotely operated system operated by the DSO.

Wind generators should be able to cope with incidents, without being disconnected from the grid, for frequency excursion within the following operation range: 47.5 Hz and 51.5 Hz.

Wind generators with installed capacity above 6 MVA should remain connected to the grid, during voltage sags caused by grid failures, providing fault ride through capability. Moreover, the units cannot absorb or inject active power when a failure occurs or when voltage is being recovered.

Wind farms with an installed capacity of over 6 MVA should also be capable to provide reactive current during voltage dips, thus contributing to support voltage in the grid during faults.

This fault ride through capability housed at the distribution level is however creating some problems when faults occur on the grid where the wind parks are connected, requiring additional adjustments to interconnection protections, since when this situation occurs islanding situations may take which is not allowed. In some cases, this may even lead to the suspension of this fault ride through functionality.

The following conditions should also be met regarding the supply of reactive energy, in steady state operating conditions, for the units connected to the distribution grids. No reactive power injection is allowed, with the exception of the facilities that are connected at the MV level, and that have less than 6 MVA installed capacity, that are required to inject 30% of reactive energy during off-valley hours.

Mini-geration (units up to 250 kW) and microgeneration (single phase units up to 5.75 kW and three-phase units up to 11.3 KW, in the case of condominium buildings) are allowed to be connected directly to the LV grid, provided that their capacity does not overpass 50% of the contracted power as a consumer. Also for LV grids, the total capacity of the microgeneration units installed in a LV network can never overpass 25% of the capacity of the MV/LV transformer that feeds this LV grid.

## South Africa

In South Africa, Eskom is the national electric power utility, and is responsible for the distribution network in predominately rural areas and smaller towns. The distribution in the cities is performed by the local municipalities. The MV distribution networks within urban areas are 11kV buried cables while the rural networks are predominately 22kV overhead conductors.

The South African network grid [64] and distribution codes [65] dictate the minimum technical requirements for all grid connected DER. The South African distribution network code also mandates each distributor to have an interconnection standard specifying the technical criteria for the connection of DER. The Eskom Distribution Standard (DST 34-1765) for the interconnection of embedded generators [66] specifies the minimum requirements for generator grid connection. The embedded generator must adhere to the minimum requirements (as stated in [64], [65], [66] and [67] in order to connect to the Eskom network. There are also guidelines and standards, setting the technical requirements, criteria, limits and all issues related to the connection of the embedded generator to the Eskom networks. The relevant information on the network planning technical standard is explained below.

MV connected DER

It is a grid code requirement that all MV connected DER must have certain capabilities e.g. the generator must be able to provide the PQ capability as required by the codes. Eskom specifies the control mode and associated power factor for grid connected generators (which must be within the generator capability). For all Eskom MV connected DER, it is a requirement that they be operated in fixed power factor for all planning studies. The default is unity power factor but the planning engineer allows some movement from unity as per the limits for rapid voltage change (RVC) as discussed further on. Power factor greater than or less than unity (PF <>1) generally results in increased technical losses. Operation in voltage control mode will typically only be considered for operational scenarios, and must not be a requirement for normal network operation. Planning studies are performed to evaluate technical constraints to integrate the generation, whilst complying with the following specific minimum technical requirements in addition to those generally mentioned in the first Chapter.

*Steady state voltage limits*

During all loading and generation patterns, voltage rise and voltage drop need to be kept within specific limits so that voltage variation at customer points of supply are within required limits, as specified in the South African electricity quality of supply regulatory standards [68] and [69]. For MV (11kV, 22kV and 33kV) networks the voltage rise on the network is limited to 1%, resulting in a maximum MV voltage of 105%. If the generator is supplied via a dedicated MV line then the voltage at the generator MV point of supply can rise to 107.5% during normal and 110% during abnormal conditions.

*Fault levels*

Connecting DER to network has the effect of increasing the fault levels in the network at the point of generation connection. This may result in the violation of equipment fault level ratings. Key elements considered include [70] [71] and [72]:

- The fault level is sensitive to the future location of other generation, and the future is uncertain and difficult to predict. The future fault level could increase significantly and as such, the generation developer must also ensure that their generating plant is rated as per Table 13 which is a design requirement. This will ensure that the generation plant will be adequately rated if the fault level at the point of connection increases up to the limit in Table 13. The actual fault level (as required for protection studies and settings) may be significantly lower and will change as fault levels in the network change.
- The equipment fault levels (considering the impact of existing generators and proposed generators) must not exceed 90% of their fault level rating.

**Table 13: Fault level limits (kA) per connection voltage level (South Africa)**

| Equipment voltage level [kV] | Short circuit rating at POC [kA] |
|---|---|
| 11 kV | 25 |
| 22 kV | 25 |
| 33 kV | 25 |
| 66 kV | 25 |
| 88 kV | 40 |

*General*

During the planning study for the connection of DER, the thermal and voltage performance of various scenarios (such as maximum load and maximum generation, maximum load and minimum generation, minimum load and maximum generation, and minimum load and minimum generation) are assessed for the existing and future networks.

**Table 14: Summary of typical planning limits for generation grid connection** [70]

| Criteria | Basis | Reference | Limit | |
|---|---|---|---|---|
| | | | **Normal** | **Contingency** |
| Thermal limits (capacity) | Normal planning philosophy | Lines and cables DGL 34-619 and transformers DGL 34-617 | Normal planning limits | Use abnormal planning limits |
| Technical losses | Normal planning philosophy | Project Evaluation Model (PEM) to optimise lifecycle costs including technical losses. | Loss optimisation only performed for normal network configuration | N/A |
| Fault level limits | Normal planning philosophy | Planning methodology standard DST 34-355, short circuit fault current management policy 46-2460 | Must not exceed 90 % of equipment fault level ratings | 100% of equipment fault level ratings |
| Voltage regulation (e.g. voltage rise) | Normal planning philosophy | Voltage regulation and apportionment limits standard DST 34-542 and NRS 048-2 | Normal voltage limits 1% voltage rise for shared network and 4.5% voltage rise for dedicated network | Abnormal voltage limits |
| Rapid voltage change (sudden loss of generation) | Non-fluctuating generation i.e. more stable (disconnection due to fault or inadvertent trip) | RSA grid code and internal Eskom planning criteria | <=5%, at minimum leading power factor of 0.975 for gen plants >= 20MW and <=5%, at minimum leading power factor of 0.9875 for gen plants < 20MW | <=5%, at minimum leading power factor of 0.95 for all gen plants >=20MW and <=5%, at minimum leading power factor of 0.975 for all gen plants < 20 MW |
| | Fluctuating generation such as solar PV or wind generation | RSA grid code and internal Eskom planning criteria | <=3%, at minimum leading power factor of 0.975 for gen plants >= 20 MW and <=3%, at minimum leading power factor of 0.9875 for gen plants < 20MW | |

Proposed criteria for LV connected DER

*Introduction*

The LV connected DER criteria summarized below are intended to guide South African distributors in terms of simple rules to be applied when assessing applications for LV connected embedded generators. The proposed criteria indicate the conditions under which LV connected generators can be connected to the utility grid without having to perform detailed network studies. Applications not meeting these criteria are proposed to follow an alternate process, which may require detailed network studies. The proposed criteria are presently in draft and are being finalized for implementation.

*Definitions*

Dedicated network: Section of utility network that exclusively supplies/connects a single customer/generator.

Generator size: In the context of this specification the generator size is the maximum change in active power flow at the point of utility connection for a generator trip (or rapid reduction in output) when generating at full active power output.

NOTE: Some or all of the power generated may be consumed by the customers' local loads. Where there is no local storage the generator size is the active power rating of the installed generation. In cases with local storage, the storage can be used to reduce the effective size of the generator by compensating for variations in generation output, hence the definition used above.

Shared network: Section of utility network that supplies/connects more than one customer/generator.

*General*

The NRS 097 series of documents specify the minimum technical requirements for LV generators connected to the South African grid. All LV grid connected generator interconnection equipment must be type-test certified, as complying with the minimum technical requirements of NRS 097-2-1.

Generator sizes greater than 350 kW shall be connected to the MV or HV networks.

The maximum permissible generation size of an individual LV customer is dependent on:

I. The type of LV network: Depends on whether the LV network supplying the customer is shared (supplies other customers) or dedicated (only supplies the customer in question), and
II. The customers Notified Maximum Demand (NMD): The NMD in many cases is determined by the LV service connection circuit breaker rating. It is the maximum load that a customer can draw from the utility network.

There are additional rules linked to the size of the MV/LV transformer and maximum loading of the associated MV feeder, as are discussed in this summary.

The LV fault level at the customer point of supply shall be greater than 210A.*Shared LV feeders*

*Shared LV feeders*

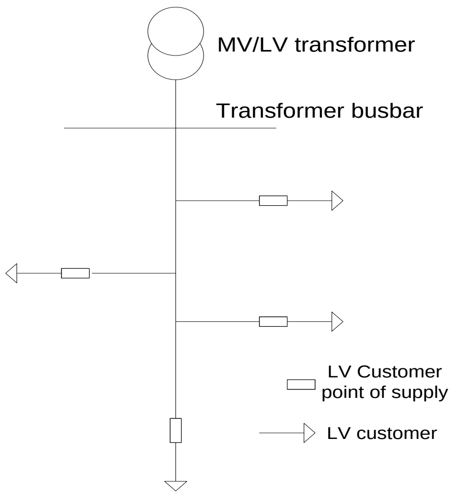



**Fig. 22 Shared LV feeder (loads and DER)**

The maximum individual generation limit in a shared LV feeder is 25% of the customer's NMD, up to a maximum of 20kW (generators >20kW must be connected via a dedicated LV feeder). The resulting maximum generator sizes for common domestic supply sizes are summarized in Table 15. NOTE: The values have been adjusted to align with VDE-AR-N 4105 and hence vary slightly from 25% of NMD.

**Table 15: Maximum individual generation limit in a shared LV (400/230V) feeder (South Africa)**

| Number of phases | Service circuit breaker size | NMD | Maximum individual generation limit |
|---|---|---|---|
| 1 | 20A | 4.65kVA | 1.2kW |
| 1 | 60A | 13.84kVA | 3.68kW |
| 3 | 60A | 41kVA | 13.8kW (4.6 kW per phase) [9] |

In shared LV feeders, any generator >4.6kW must be balanced across 3 phases.

For LV customers with supplies greater than those given in table 15, the maximum individual generation limit in a shared LV feeder is 25% of the customer's NMD. For example, a LV customer with a 100kVA NMD supplied via a shared LV feeder could connect up to 100 x 25% = 25kW of generation. Since 25 kW is greater than the 20 kW limit for a shared feeder, the maximum size is 20 kW and as 20 kW is greater than the 4.6 kW single phase limit, it must be 3-phase connected.

If the maximum individual generation limit is exceeded, the customer could potentially be connected through a dedicated LV feeder, such that the generator is supplied through a dedicated LV feeder (and the dedicated LV feeder limits apply). Alternatively the customer can apply for an increased NMD e.g. if a customer with a single phase 60 A supply wants to install a generator greater than 3.68 kW, then the customer could apply for an upgraded supply to 3 phase 60 A whereby the maximum generator limit increases to 13.8 kW.

In addition to the above rules, the total generation supplied by shared LV feeders is limited to 25% of the MV/LV transformer rating. For example, a 200kVA MV/LV transformer can supply up to 50kW of generation supplied via shared LV feeders connected to that transformer.

*Dedicated LV feeder*

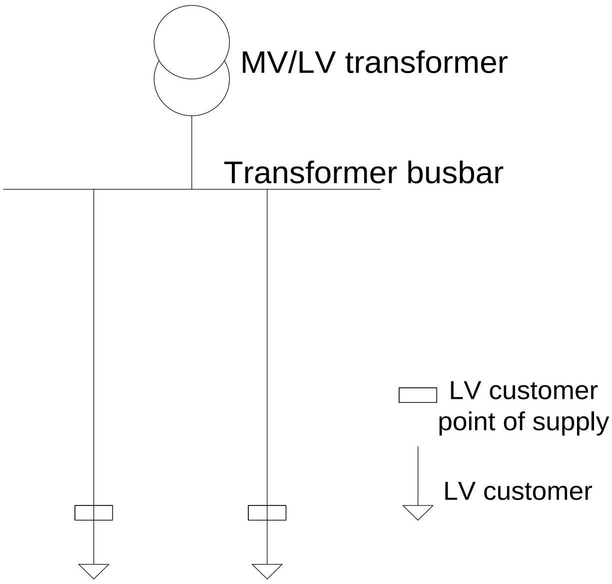



**Fig. 23 Dedicated LV feeder(s) (only DER)**

In dedicated LV feeders (see Fig. 24), the maximum individual generation limit is a function of:

I. The Notified Maximum Demand: The maximum generator size is limited to 75% of the NMD. Generators greater than 4.6 kW shall be balanced across the available phases. Customers with dedicated single phase supplies supplied by a dedicated MV/LV transformer (e.g. 16 kVA MV/LV dedicated supplies in rural areas) shall be allowed to connect up to 13.8 kW on that single phase but shall not exceed 75% of their NMD.

[9] All generators greater than 4.6kW must be 3phase connected

II. The dedicated feeder cable size (voltage rise is limited to 1%). Fig. 24.illustrates the maximum generator size as a function of the dedicated LV feeder cable size and length.

Note that if the dedicated LV feeder cable size is the constraint, it could be upgraded at the customer's cost.

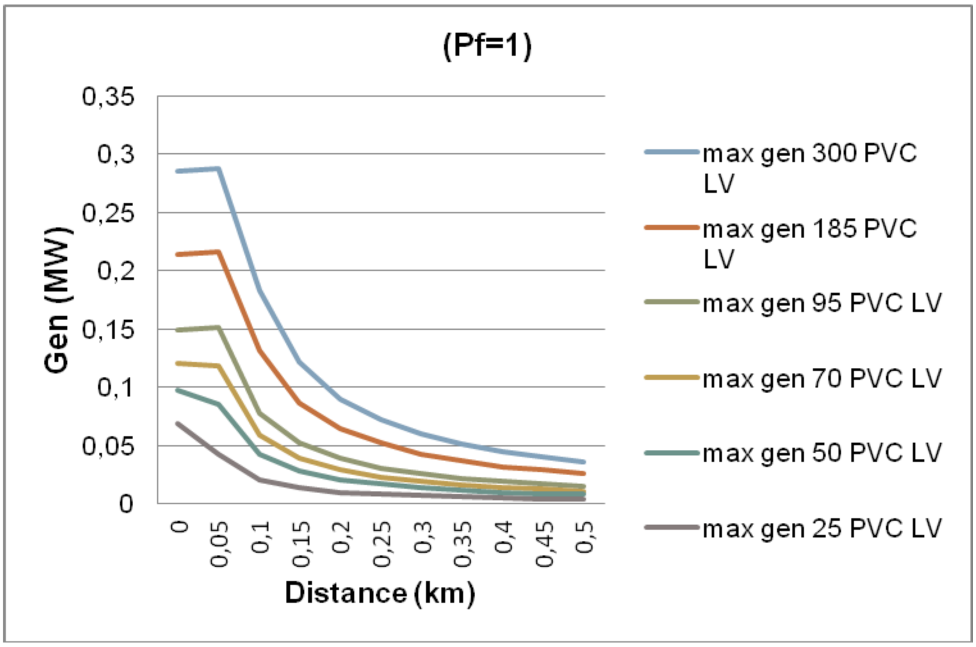



**Fig. 24 Dedicated LV feeder maximum gen sizes as a function of cable size and distance (South Africa)**

Connections that only supply generators will be made via a dedicated LV feeder. For instance, if the customer does not have load and only injects power into the network, then, the connection must be made via a dedicated feeder with a minimum size as per Fig. 24. As the customer is not a conventional load and does not have a NMD, the maximum generator size will be limited by the dedicated LV feeder size (Fig. 24) and the maximum MV/LV transformer limit (see additional rules below).

*Additional rules*

The following rules apply in addition to the rules for shared and dedicated LV feeder connected generators:

I. The total generation (i.e. shared LV generation + dedicated LV generation) supplied by a MV/LV transformer shall be less than 75% of the MV/LV transformer rating, and

II. The total generation supplied by a MV feeder shall be less than 15% of the MV feeder peak load.

If both criteria are not met, then additional generation does not meet the simplified connection criteria; hence cannot be connected to the network without more detailed studies.

Fault level related issues are not anticipated for inverter based generators as the fault current contribution is typically limited to the converter current rating. Equipment fault current ratings should be checked for synchronous or asynchronous generators greater than 13.8kW.

*Summary*

A summary of the connection criteria is shown in Fig. 25 and a flow chart is illustrated in Fig. 26

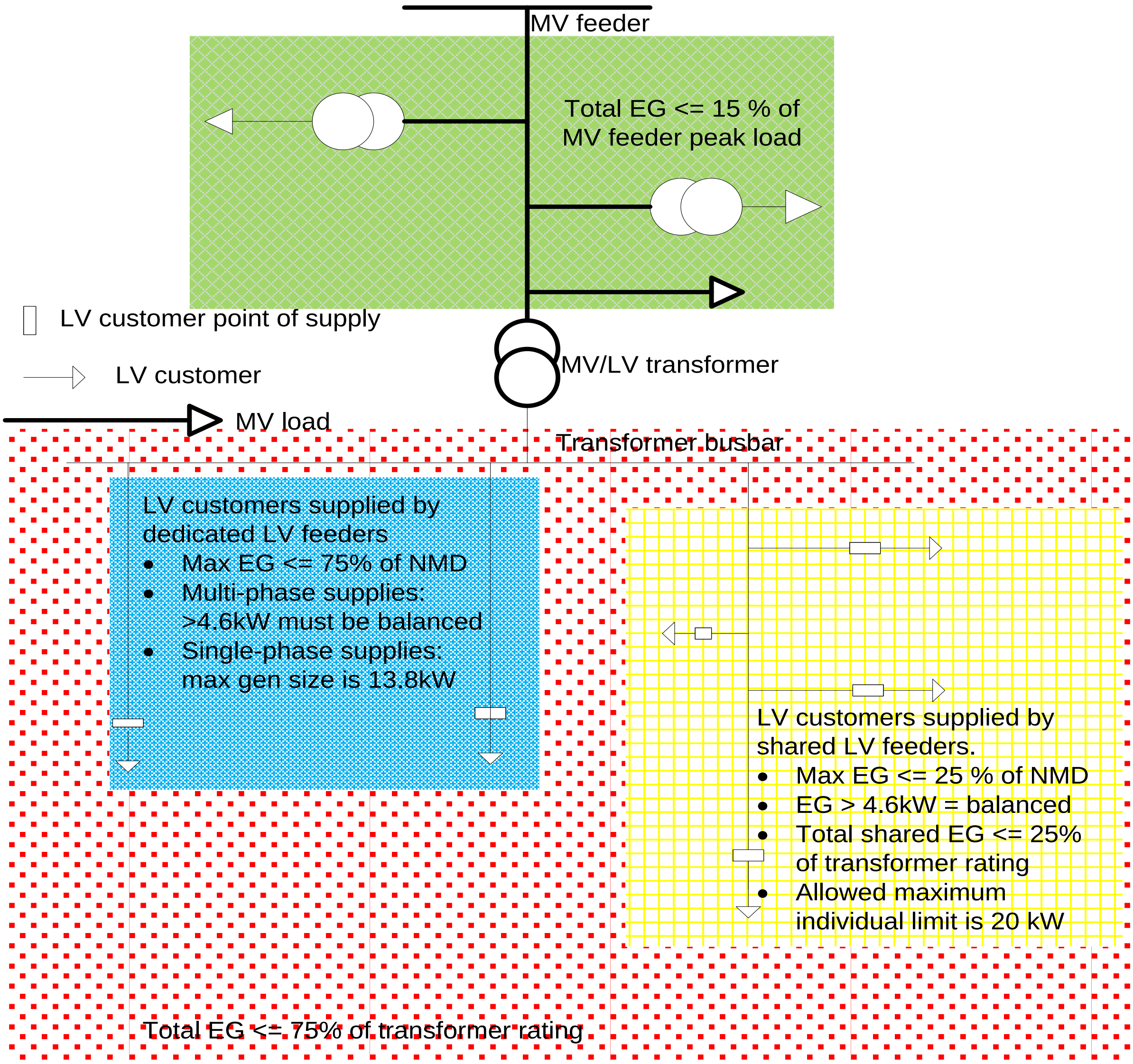
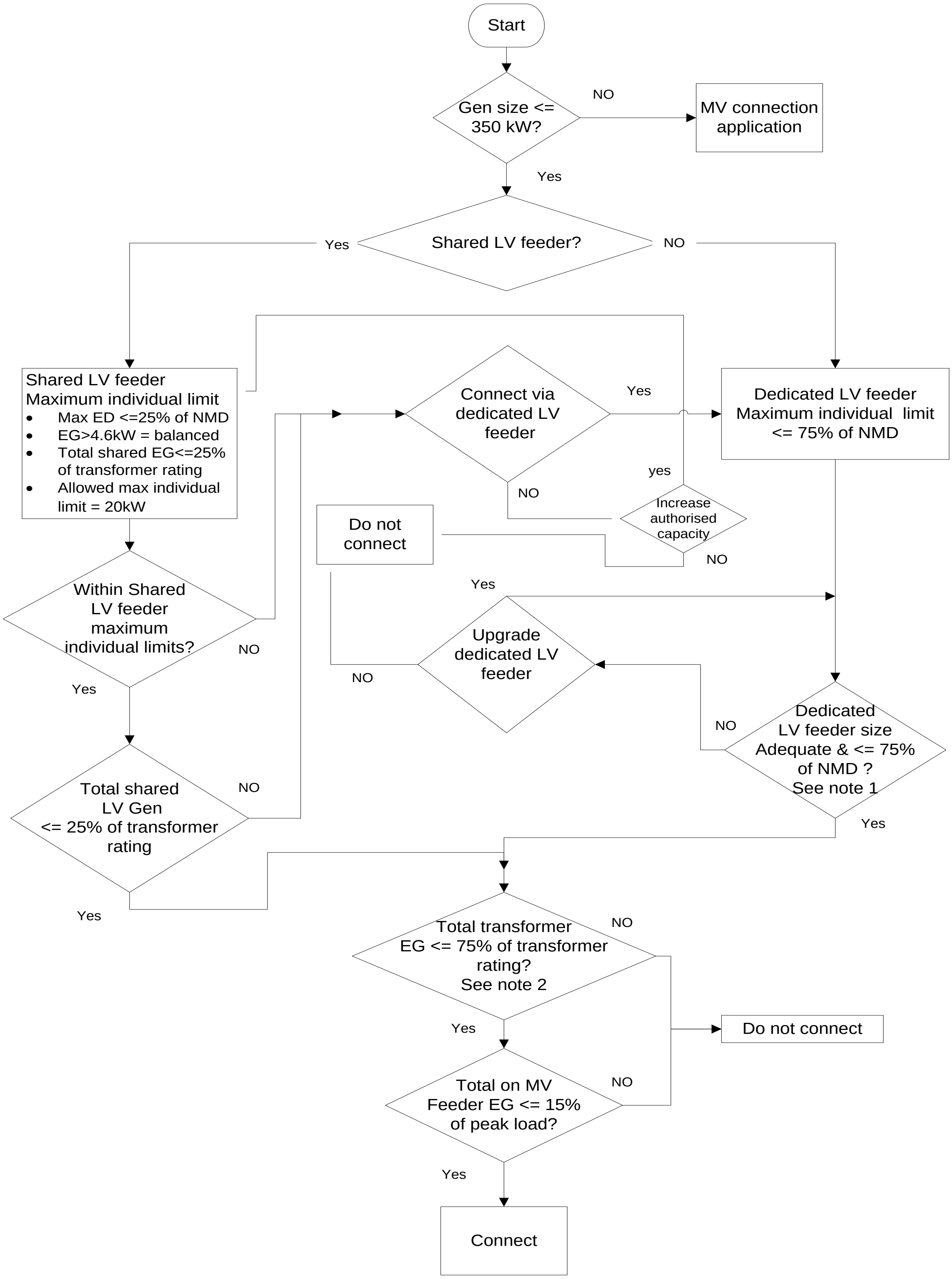



**Fig. 25 Summary of simplified connection criteria (South Africa)**




Note 1: see cable size plots in Fig. 24
Note 2: shared LV + dedicated LV

**Fig. 26 LV connected generation simplified connection technical evaluation criteria (South Africa)**

*Basis for LV connection criteria*

The technical limits that constrain the amount of LV connected generation are as follows:

- Thermal ratings of equipment (lines, cables and transformers) may not be exceeded.
- LV voltage regulation must be within the limits specified via NRS048-2 (LV voltages at the customer point of supply shall be within ±10%).
- The maximum change in LV voltage (due to voltage drop/rise in the MV/LV transformer and LV feeders) due to DER is limited to 3%. This is a common international practice where the generation is variable. This will ensure that voltage changes due to short term variations in generation output are within acceptable limits e.g. every time there is a cloud transient the LV voltages should not vary by more than 3% (as PV output changes). From a voltage change perspective, it does not matter how much of the generation is consumed locally or fed back into the network. When the generation output changes the loading in the utility network, changes accordingly the utility network supplied loads that would have been supplied by the embedded generator. Hence voltage change magnitudes (due to changes in generation output) are dependent on the generation size, and not on the net export magnitude into the utility network.
- Islanding of the utility network is not allowed.

Application of the above limits resulted in the following proposed criteria as documented earlier:

- Voltage rise on LV feeders shall be limited to a maximum of 1%. This value is informed by the NRS048 voltage limits, MV voltage control practices and the MV/LV transformer voltage ratio and tap settings.
- Voltage rise across the MV/LV transformer shall be limited such that the NRS048-2 voltage limits are not exceeded. The maximum generation connected to a MV/LV transformer is limited to 75% of the transformer rating understanding that this may result in over voltage problems on LV feeders where there is further voltage rise. The 75% limit is hence high but in reality the next flow through the transformer into the MV network is expected to be significantly less due to the customer loads. A 75% limit will also ensure that the transformer will not be overloaded during periods of maximum generation and minimum loading.
- The individual customer limit of 75% of NMD on dedicated LV feeders is informed by the MV/LV transformer limit of 75%. This approach provides customers with equitable access to the available generation capacity as limited by the MV/LV transformer rating. It will also ensure that service cables will not be overloaded under conditions of maximum generation and low loading.
- The dedicated LV feeder minimum size is based on a maximum voltage rise of 1% (Fig. 24).
- The individual customer limit of 25% of NMD on shared LV feeders is informed by an analysis of typical LV feeder designs whereby the individual generator size was scaled as a function of the design loading limits and the generation penetration level (% of customers that install a generator). The voltage rise and change in voltage were calculated assuming that the installed generation is reasonably balanced (connected to the same phases as the load). Allowing the individual customer maximum to increases requires that the penetration level value be reduced such that technical limits are complied with. An individual limit of 25% of NMD will typically support a penetration level of 30% to 50%, which is considered reasonable and an acceptable compromise between restricting individual generator sizes versus restricting penetration levels. It must be noted that a primary limitation is the maximum voltage change of 3%.
- The total generation connected to a MV feeder is limited to 15% of the MV feeder maximum loading. This value is informed by practices in the US and Europe, and is based on the ratio of maximum to minimum feeder loading for typical consumer load profiles. A limit of 15% will ensure a low probability of reverse power flow into the MV feeder source, thereby preventing voltage rise in the MV feeder and reducing the possibility of an island for operation of MV switches and protection.

## South Korea

In Korea, the Transmission & Distribution System Operator, KEPCO, is responsible for the grid code and technical guideline for DER interconnection into distribution system. The guideline was initially established in April, 2005 and the current version of the guideline was revised in June, 2012 in order to promote the integration of renewable energy resources to the distribution system based on increasing hosting capacity of feeders.

The voltage level at which the DER can be connected to, is determined by the proposed DER capacity as shown in the table below.

**Table 16: Maximum individual generation limit**

| Proposed capacity(P) of DER | Connection Voltage Level | Remarks |
|---|---|---|
| P < 100 kW | Low Voltage | 220/380 V |
| 100 kW ≤ P ≤ 10 MW (20 MW) [a)] | Medium Voltage | 13.2/22.9 kV |

a) It needs special conductor. Therefore the general maximum capacity of DER on MV system is 10 MW.

As far as interconnection to medium voltage system is concerned, total installed capacity of DER for MV interconnection is limited to 20% of nominal power of a HV/MV transformer at substation. The maximum hosting capacity of distribution feeder is 100% of the feeder's operating limit, and thus it can be 10 MW or 20 MW, depending on conductor size of the feeder.

According to the grid code, the proposed DER can be connected to public distribution line as long as the following conditions are satisfied:

- Service voltage should be within 220±13V.
- Sudden voltage changes should be within 3~5% of the nominal.
- Short-circuit level should not exceed the nominal rating of switch gear and circuit breaker.
- Possibility of incorrect operation for protection scheme should be checked and solutions for the faulty operation should be made an agreement, if needed.

In case of the following conditions, the technical evaluation procedure can be simplified without detailed technical studies as a rule of thumb:

- Aggregate nominal power of all DER that integrated into a HV/MV transformer must be less than 15% of the HV/MV transformer nominal power at substation.
- And aggregate nominal power of all DER that interconnected to a feeder must be less than 15% of the feeder's operating limit.

The following flow chart shows in detail the technical methodology applied for interconnection feasibility study which includes both the evaluation of the impact on the MV system and the determination of the interconnection scheme that is required to be applied.

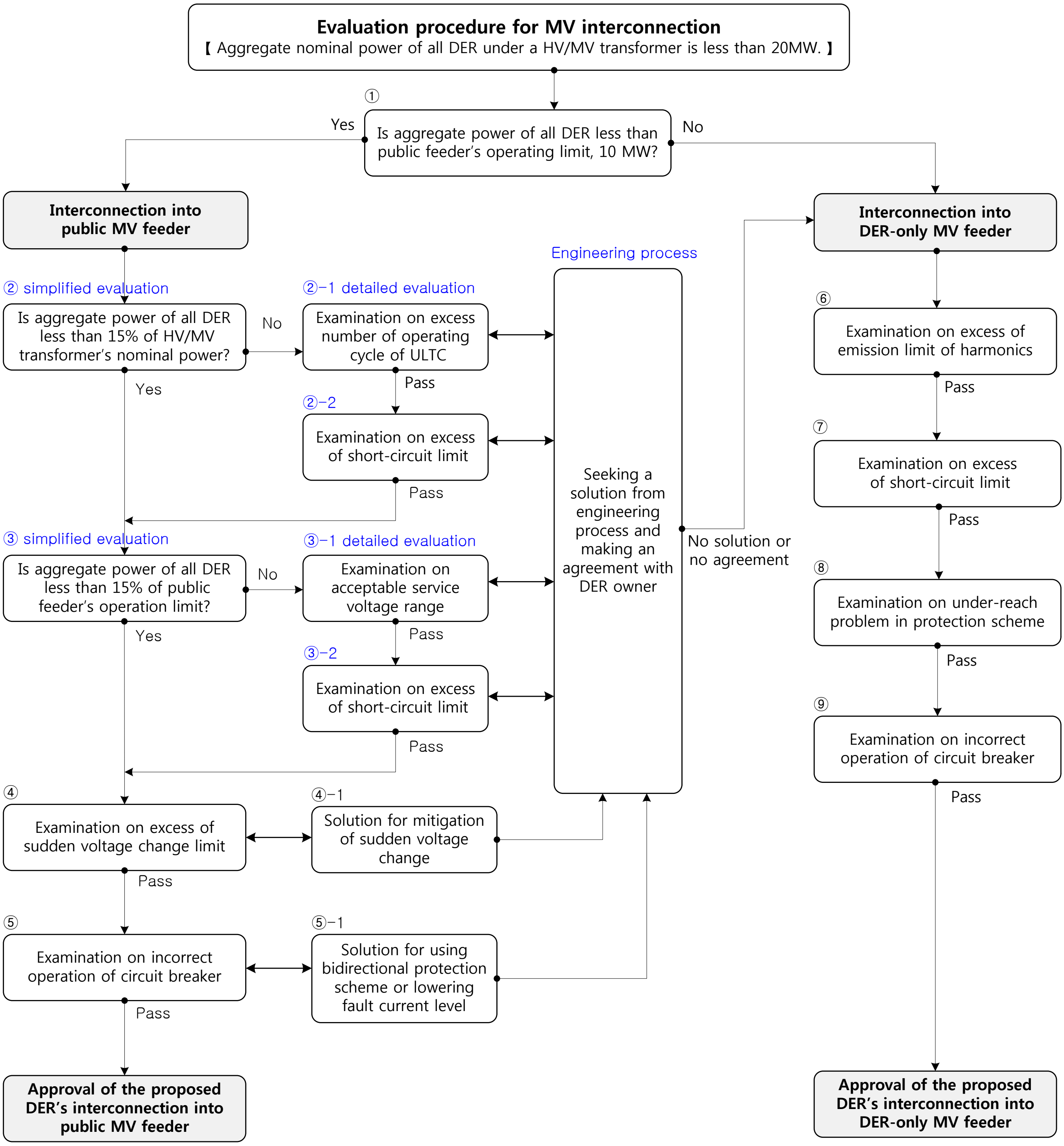



**Fig. 27 Flow chart that shows the technical methodology implemented in MV networks (South Korea)**

A case study is presented in Annex H.

As far as interconnection to low voltage system is concerned, the proposed nominal power of the DER that is to be connected must be less than 100 kW, the aggregate nominal power of all DER connected to the LV network must be less than 100% of the nominal power of a MV/LV transformer and the following conditions has to be satisfied:

- Voltage variation at the MV/LV transformer due to interconnection of the newly proposed DER should not exceed the upper limit of service voltage, 233V at customers that are directly connected to the transformer.
- Steady-state voltage variation should be less than 3% of the nominal.
- Sudden voltage change should be less than 6% of the nominal.

In case of the following conditions, the technical evaluation procedure can be simplified without detailed technical studies as a rule of thumb:

- Aggregate nominal power of all DER that integrated into a MV/LV transformer must be less than 50% of nominal power of the MV/LV transformer (The proposed DER can be connected into DER-only LV line).
- Aggregate nominal power of all DER that integrated into a MV/LV transformer must be less than 25% of nominal power of the MV/LV transformer (The proposed DER can be connected into public LV line).

The following flow chart shows in detail the technical methodology applied for interconnection feasibility study which includes both the evaluation of the impact on the LV system and the determination of the interconnection scheme that is required to be applied.

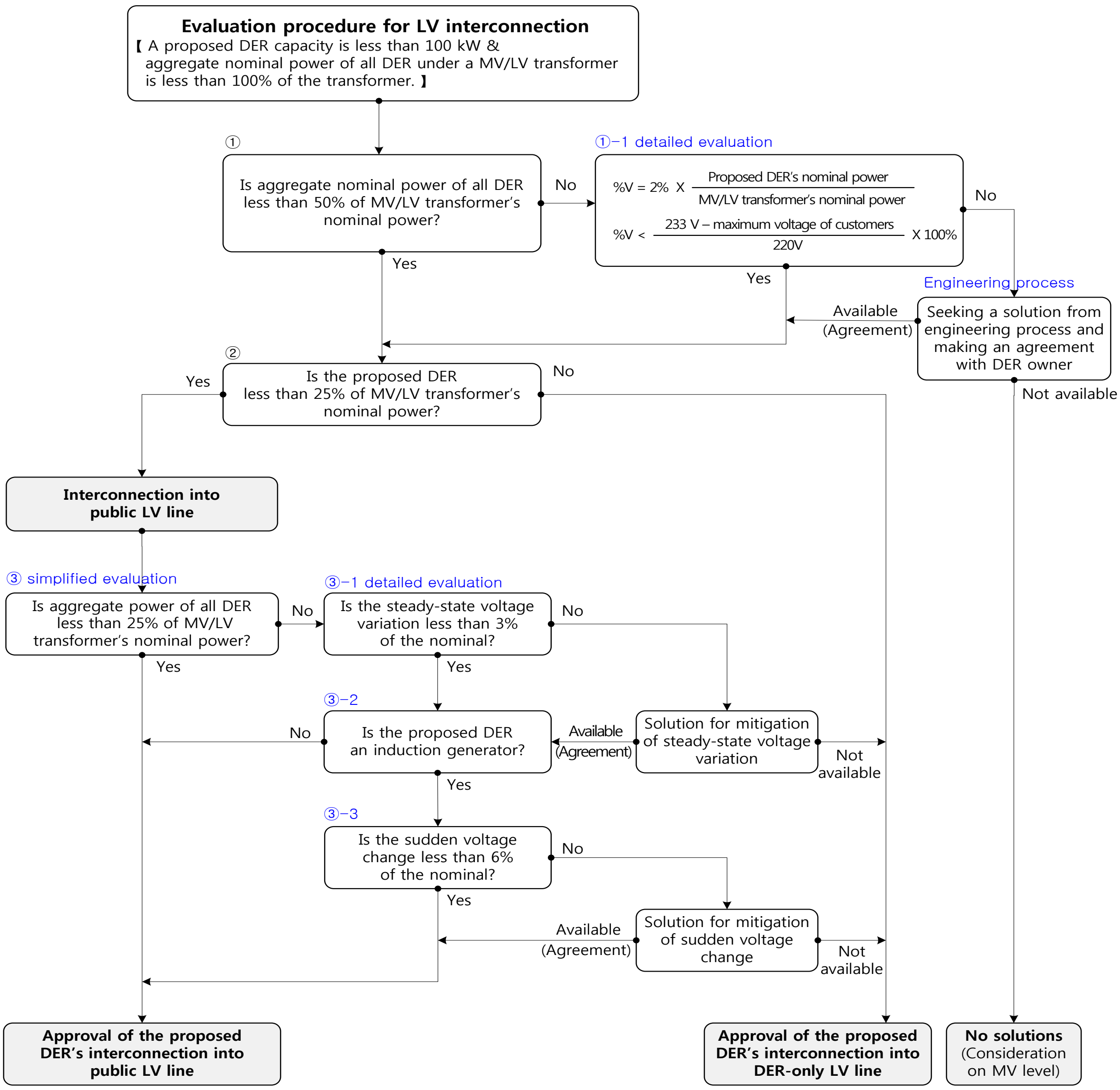



**Fig. 28 Flow chart that shows the technical methodology implemented in LV networks (South Korea)**

## Spain

In Spain, the most important technical requirements for the connection of DER to the public distribution network are specified in [15]:

- Order 5/9/1985: Administrative and technical rules for the operation and interconnection to the grid of hydroelectric power plants up to 5 MVA and "autogeneration plants".
- RD 1663/2000: interconnection of PV installations to the low voltage grid.
- Decision of 4th of October 2006 of the General Secretary for Energy, "Response requirements for wind generators in case of voltage dips".
- RD 842/2002: Spanish Low Voltage Code [16].

Other technical guidelines which define the necessary requirements and the connection feasibility study are the following ones [16]:

- Condiciones tecnicas de la installacion de autoproductores, Iberdrola.
- Normativa de productores en Regimen Especial Informacion para la solicitud de Conexion a la red de VIESGO, Viesgo.

In low voltage network, the maximum aggregated nominal power of the DER must be less than 100 kVA or 60 kVA in grids with 380/220 V or with 220/127 V respectively. In medium and high voltage networks, plants with asynchronous generators can be connected up to 5000 kVA and plants with synchronous generators up to 10000 kVA.

As for the feeders, the aggregate nominal power of DER must be less than 50% of the capacity of the feeder[10] to which the DER will be connected [73]. If the available capacity of the specific feeder, to which the DER is to be connected, is smaller than the nominal power of a pv power plant, the DNO should take all the required provisions (e.g. network modifications) so as the connection to be feasible [16].

As for the transformers and the substations, the aggregated nominal power of DER must be less than 50% of the capacity of them [73]. Otherwise, the DNO must provide an alternative solution for the connection of the DER [16].

The DER, that the DNO has to take into account, so as to verify the previous conditions, should include the already connected DER, plus the unexpired interconnection offers plus the applicant's plant [73].

The permitted voltage rise, due to the steady state operation of DER, must not be higher than 2% of the nominal voltage. The limits that are set by the norm EN 50160 and RD 1955/2000 are ±10% and ±7% respectively. According to RD 1955/2000, in case of the distribution step between 1 kV and 36 kV the previous permitted band is even narrower (±5.6%). Problems related to voltage regulation might arise in especially long lines, in which the DER are connected to points far from the beginning of the line, beyond its central point. This situation happens due to the fact that the on load tap changer raises the voltage at the busbars of the substation so as to maintain the voltage at the distant nodes of the line above the lowest permitted limit. Thus, when the DER inject power into the line, it is possible to raise the voltage beyond the upper limits and the near customers have to face too high voltages. Therefore, if the conditions do not vary, the customer will have too high voltages at some times (when the DER are connected) and too low voltages at other times (when the DER are disconnected) or even both [73]. Voltage regulation techniques presently used are adapted for bidirectional power flows at MV levels in the biggest part of the Spanish network. In the remaining case adaptation is possible and indeed foreseen for the new networks and extensions of existing networks [74].

The increase of short-circuit current of the grid due to the interconnection of a synchronous generator must be compatible with the conditions of the grid. The aggregated nominal power of the connected DER must not be greater than 10% of short-circuit at the PCC in order to avoid undesirable impact to power quality [73]. Especially for wind power plants, the equivalent limit is set to be 5% [16]. According to Viesgo's technical guideline, the total installed power of wind plants must not exceed the 10% of the maximum demand of the grid, in keeping with the

[10] Thermal limit

available regulation capacity. This rule is implemented only in the Viesgo's network [16]. The design short circuit capacity depends on the voltage level we refer to. In distribution networks, this network design value is around 25 kA [75].

According to Iberdrola, there are serious concerns related to the increased risk of electrical hazard and the loss of supplied power quality in cases where the network is disconnected for any reason (network breakdown due to failure, maintenance, error, etc) and the consumption and generation are close enough. Under such circumstances, the DER may remain connected, which means, on one hand, a lack of safety for the personnel who are working "in-situ" and, on the other hand, the supplied power quality decreases because both voltage and frequency levels remain uncontrollable resulting possibly in violating the determined limits. Until the DER are disconnected due to the operation of voltage protection relays, loads may be affected negatively. This situation is more likely to happen if the DER are connected to low voltage network due to their non obligation of providing remote tripping device [73].

## UK

In Great Britain, the Distribution Code specifies standards for the design and operation of distribution networks [5]. In addition there are two relevant technical guidelines [5]:

- Engineering Recommendation G59/2, (2010): Recommendations for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators.
- Engineering Recommendation G83/2, (2012): Recommendations for the connection of small-scale embedded generators (up to 16A per phase) in parallel with public low-voltage distribution networks.

As far as international standards are concerned, EN 50160 has been adopted.

The interconnection, to an electricity distribution network, generation scheme which is defined by DNO affects the operation and performance of the network. The DNO is concerned to maintain network safety, and to ensure that operation of the scheme does not cause problems for nearby electricity users. In particular the DNO will wish to establish that [5], [11]:

- Voltage levels are kept within statutory limits.
- If transformers can operate with reverse power flows.
- Thermal ratings of equipment are not exceeded.
- Fault ratings of switchgear and cables are not exceeded.
- Voltage disturbance effects in terms of step change, flicker and harmonics are kept to a minimum and within nationally accepted limits.

These can be assessed by conducting load flow and fault calculation studies which result in the following [5]:

- Load Flows:
    - Current flows in each branch of the network.
    - Sending and receiving end real and reactive power flows for each branch.
    - Voltage conditions at each node.
    - Voltage boost (+/-) at each voltage controlled node.
    - Losses.
- Fault Level – for each faulted node:
    - Total fault current at the faulted node.
    - Angle of fault current relative to the node reference voltage.
    - Fault current distribution.

In more detail:

- Voltage regulation

  The bandwidth and time delay of the voltage control schemes are coordinated with the transformers connected at the voltage level above. The voltage control scheme of a 33/11kV transformer will have a narrow bandwidth and long time delay. This ensures that the 132/33kV transformers have time to correct a system wide voltage change before a local voltage excursion is corrected, avoiding unnecessary tap operation [6]. In UK, the electric system is designed to maximize the principle of one-way power flow and the network operators set the target voltage at a primary 33/11kV substation at 11kV +1% (typically). To avoid excessive tapping of the automatic on-load tap changer a bandwidth of ±1% is used. The maximum allowable voltage at the 11kV busbar is thus 11kV +2%. The increment of +2% above the nominal voltage allows for a voltage drop along the distribution line. This ensures that low voltage customers receive a voltage of between 230V+10% (253V) & 230V-6% (216V) at their terminals independent of the load being consumed. This enables compliance with statutory limits. The maximum 11 kV busbar voltage (11kV +2%) transformed to LV voltage gives 255V. However, due to residual load the voltage drop in the LV main and service cable avoids the customer receiving voltages outside the statutory limits [76]. Similar coordination exists between the 132/33kV transformers and the 400/132kV transformers [6].

  In rural areas Line Drop Compensation (LDC) is sometimes used to boost the voltage at the 11kV busbars during periods of high demand by taking into consideration the R/X characteristics of the circuits [5], [6]. Other times, the On Load Tap Changers are used to maintain the lower voltage busbar constant within a narrow bandwidth, typically ±1.75%, about a target voltage. This ensures a substantially constant low voltage for variations in the higher voltage system and voltage drop within the feeding transformer [5].

  MV voltage regulators have been used in a small number of cases to control voltage rise and increase the amount of distributed generation that can be connected to a particular feeder and conversely to boost voltage on long feeders supplying load [6]. MV/0.4kV distribution transformers have off load taps with a range of ±5% in 2.5% steps. These are typically set up so that distribution transformers located at the far end of the feeder have a lower tap setting than those closest to the substation in order to compensate for the increase in voltage drop along the 11kV feeder [6]. The operating fixed tap position is chosen in conjunction with the calculated appropriate volt drop in the 11kV and LV feeder to satisfy two basic criteria [5]:

  - at minimum 11kV source voltage and maximum feeder demand the voltage at a remote end consumer is no less than the statutory minimum; and
  - at maximum 11kV source voltage and minimum feeder demand the voltage at the transformer LV bus bar or first LV customer does not exceed the statutory maximum.

  In UK, low voltage radial feeders are normally designed to have a maximum voltage drop of 7% from the substation busbars to any customer’s terminals. This is based on a transformer voltage ratio of 11kV/433/250V (which allows for a full load busbar voltage of 415/240V) and the requirement to comply with the Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR) which states that the declared voltage at the customer’s terminals must be 230V +10% / -6% [6].

- Reverse power flow

  The considerations discussed in Chapter 1 directly apply here.

- Thermal rating

  The considerations discussed in Chapter 1 directly apply here.

- Short circuit

Many DNOs use common standards for the specification of circuit breakers to be fitted in their networks. As a result, similar values are often specified for design fault levels in DNO networks. The following Table 17 below shows typical design fault levels at some common UK distribution voltages.

**Table 17: Typical design fault levels for common UK distribution voltages** [5]

| System voltage (kV) | 11 | 33 | 132 |
|---|---|---|---|
| Design fault level (MVA) | 250 | 750 | 3,500 |

Short circuit current calculations should take into account the contributions from all synchronous and asynchronous infeeds including induction motors. The prospective short circuit "make" and "break" duties on switchgear should be calculated to ensure that plant is not potentially over-stressed. The maximum short circuit duty might not occur under maximum generation conditions; it may occur during planned or automatic operations carried out either on the Distribution or Transmission System [11]. In more detail, the Fig. 29 shows the distribution of headroom availability, both in terms of make current and break current, in urban MV networks across a number of DNOs in GB [9].

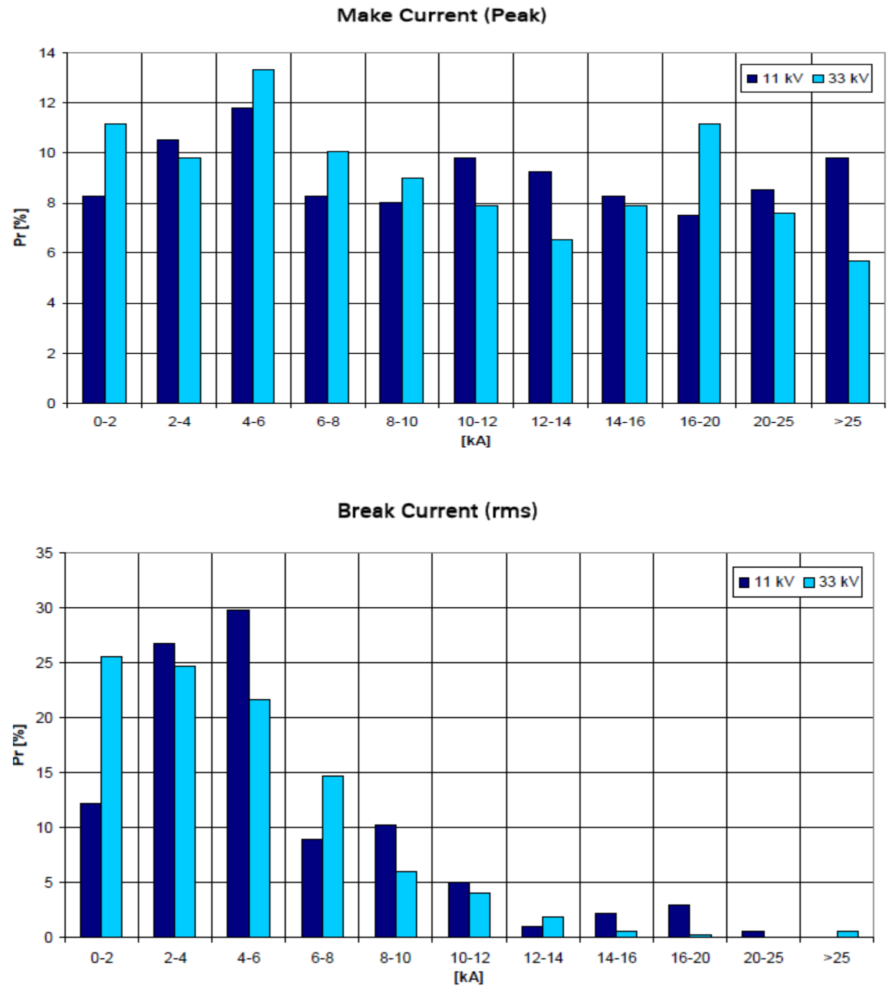



**Fig. 29 Distribution of Headroom Availability in Urban MV Networks (UK)** [9]

The horizontal axis shows the (categorised) available headroom in kA. For each bar the vertical axis shows the percentage of substations that belong to this category. For instance: of all 11kV sub-stations, 8% have a “make” current headroom of more than 8 kA but less than 10 kA. By summing the values for the two leftmost bars, it follows that the percentage of 11kV substations with less than 4kA make current headroom equals approximately 18%.It can be seen from Fig. 29 that there is a significant proportion of substations in urban MV networks that have less than 4kA headroom availability, both in terms of make current and break current [9]. Where only the “make” duty of the switchgear is exceeded there is the option to manage this situation by temporarily reducing the network fault level before closing a circuit breaker. Where the network fault level is above the “break” duty of the switchgear a permanent solution is required [6].

The electrical characteristics of synchronous generators, induction generators and electronic inverters are quite different, particularly with respect to fault level contribution and harmonics. The following Table 18 summarizes the impact of different DER on short circuit [5].

**Table 18: Impact of different DER technologies on fault level** [5]

| | Synchronous generators | Induction Generators | Electronic Inverters |
|---|---|---|---|
| **Fault Contribution** | high | low | low |

According to several analysis, in the period of 2010, the main area of concern with respect to fault levels is in urban MV networks, where there is a significant proportion of substations that do not have sufficient fault level headroom to accommodate additional DG of the type that would typically be connected to such substations. There will also be a small number of (rural) HV substations where the fault level contribution from large scale DER (e.g. wind) projects would be sufficient to make them exceed their design limits, thus requiring major reinforcement works [9].

The level of penetration of DG on the LV network will increase, but by 2010 will still only be an extremely small proportion of total energy demand. Even at 100% penetration the likely worst case increase in fault levels will be typically 6–7%. This means that it is likely that there will only be very few situations where network reconfiguration or uprating of equipment is required to address fault level issues [9].

The connection of distributed generation can change the voltage profile and consequently the above described policy in voltage regulation. The DNO SP Power Systems uses the following rule for determining the limit for connection of any generators to the 11 kV network [76]:

Capacity (MVA) ≤ 4 x generator capacity (MVA) x distance from substation (km)

For example, a 2 MVA generator can be connected up to 2 km from the primary substation or a 1 MVA generator can be connected up to 4 km away, etc. Above this, network studies have to be carried out in order to confirm that the generator would not adversely affect the quality of supply to existing customers [76].

## USA

In USA there is a variety of interconnection-related requirements that the DNOs implement. Standardisation organisations relevant to the interconnection of DER in the USA are the following [8]:

- National Fire Protection Association (which published the National Electric Code: NEC).
- Institute of Electrical and Electronics Engineers, IEEE (which issued for example the IEEE 1547 series) [8].
- Underwriters Laboratories, UL (safety testing and certification organisation, issued for example UL 1741).

As for the technical procedure of assessing the impact of DG on the network, the FERC standardized interconnection procedures (Federal Energy Regulatory Commission) or similar to them have been adopted in the majority of States. As far as the technical content of the interconnection feasibility study is concerned, IEEE 1547 has been adopted in almost all States.

In the following, several guidelines and regulations, applicable in USA, are outlined. A fundamental idea in most of them is that the DNOs set specific thresholds concerning several technical criteria (short-circuit, load to generation ratio etc.) that are considered to provide a safe-side evaluation of the hosting capacity of the network. If these criteria are met, no additional studies are required, otherwise specific studies have to be carried out.

**FEDERAL-USA**

According to [77] there are two interconnection processes that are applied, a simplified and a more detailed one.

Fast Track Process is used if the nominal power of the DER is lower than 2 MW [77]:

- For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider’s electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.
- The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.
- The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

Study Process [77] is used if either the nominal power of DER is lower than 2 MW and the fast track process has failed or if it is greater than 2 MW. A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary.

Similar to the above mentioned processes (or the whole as it is) have been adopted by several States such as Colorado, Florida, Illinois, Iowa, Kansas etc.

**Note**[11]: Apart from the need to address issues related to voltage regulation, reverse power flows and thermal limits of network equipment, the several load-to-generation ratios used as DER penetration limits derive also from unintentional islanding considerations. If the aggregate nominal power of DER is less than one-third of the minimum load according to [7], it is generally agreed that, should an unintentional island form, the DER will be unable to continue energizing the load connected and maintain acceptable voltage and frequency. The origin of this 3-to-1 load-to-generation factor is an IEEE [78] paper based on simulations and field tests of induction and synchronous generation islanded with various amounts of power factor-correcting capacitors. It was shown that as the pre-island loading approached three times the generation, no excitation condition could exist to support the continued power generation. Because minimum loads are rarely well-documented and can vary, using a conservative load-to-generation criterion of 3-to-1 gives a margin against future changes in the customer’s minimum load. However, a 2-to-1 (50%) ratio may be acceptable in some applications. According to [7], if a 3-to-1 ratio applies and the minimum load is 50% of the maximum, then a 15% limit on the peak load is derived. According to [79], if the load to generation criterion is 3-to-1 and the minimum to maximum load ratio is 1-to-5, then the limit becomes 7.5%. For installations in which the DER is interfaced through inverters, the need for margin to guard against future drops in minimum load also exists, and the 3-to-1 rule still seems prudent.

[11] This Note is applicable in the majority of States in USA and in Canada

## California

In California, Rule 21 is the technical guideline that is implemented for the interconnection of DER to the network. All applications for interconnection receive Initial Review (i.e. they are screened) with the goal of passing those that can be approved quickly without an Interconnection Study. Those that do not pass the Initial Review have a second chance of passing quickly following a Supplemental Review. There are thus three levels of review, in order of reducing costs and complexity [80]:

- Initial Review (Screening).
- Supplemental Review.
- Interconnection Study.

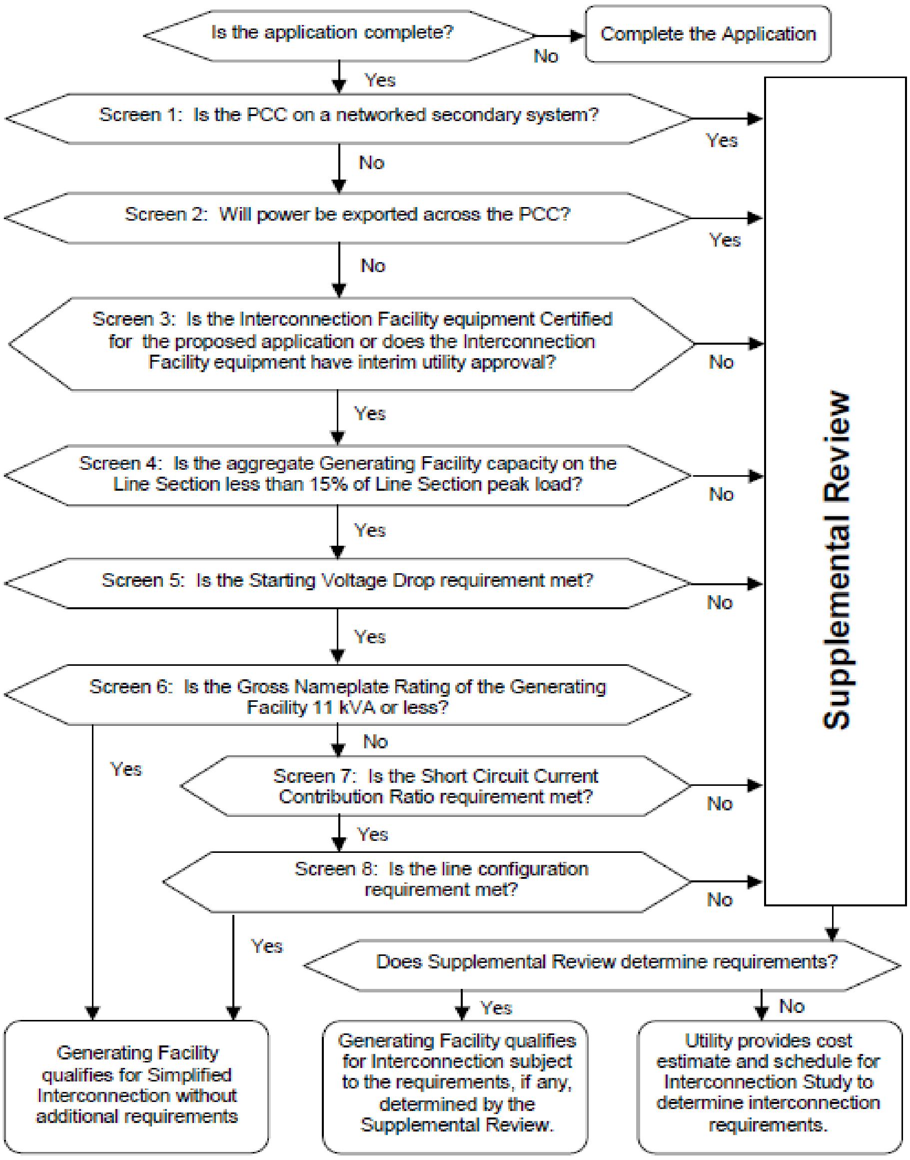



**Fig. 30 Flow chart of screening criteria (USA - California)** [80]

In more detail [80]:

Screen 2 [80]

- To ensure power is never exported, a reverse power Protective Function must be implemented at the PCC. Default setting shall be 0.1% (export) of transformer rating, with a maximum 2.0-second time delay.
- To insure at least a minimum import of power, an under-power Protective Function must be implemented at the PCC. Default setting shall be 5% (import) of the Generating Facility Gross Nameplate Rating, with maximum 2.0-second time delay.
- To limit the incidental export of power, all of the following conditions must be met:
  - The aggregate capacity of the Generating Facility must be no more than 25% of the nominal ampere rating of the customer's Service Equipment.
  - The total aggregate Generating Facility capacity must be no more than 50% of the service transformer rating. (This capacity requirement does not apply to customers taking primary service without an intervening transformer).
  - The Generating Facility must be certified as Non-Islanding.
- To ensure that the relative size (capacity) of the Generating Facility compared to facility load results in no export of power without the use of additional devices, the Generating Facility capacity must be no greater than 50% of the customer's verifiable minimum load over the last 12 months.

Screen 4 [81]

The 15% line section peak load screen is meant as a catchall for a variety of potential problems that can occur as the level of penetration of generation within the distribution system increases.

Screen 5 [80]

- Electrical Corporation may determine that the Generating Facility's starting inrush current is equal to or less than the continuous ampere rating of the customer's service equipment.
- The utility may determine the impedances of service distribution transformer (if present) and secondary conductors to customer's service equipment and perform a voltage drop calculation. Alternatively, Electrical Corporation may use tables or nomographs to determine the voltage drop. Voltage drops caused by starting a Generator as a motor must be less than 2.5% for primary interconnection (e.g. at 12 kV) and 5% for secondary interconnections through a distribution transformer.

Screen 7 [80]

The Short Circuit Current Contribution Screen consists of two criteria, both of which must be met when applicable:

- At primary side (high side) of the Dedicated Distribution Transformer, the sum of the Short Circuit Contribution Ratios (SCCR)[12] of all Generating Facilities on the Distribution System circuit may not exceed 0.1 (10%).
- At secondary (low side) of a shared distribution transformer, the short circuit contribution of the proposed Generating Facility must be less than or equal to 2.5% of the interrupting rating of the Producer's service equipment.

Screen 8 [80]

If the Generating Facility is served by a three-phase four wire service or if the Distribution System connected to the Generating Facility is a mixture of three and four wire systems, then aggregate Generating Facility capacity that exceeds 10% of the Line Section peak load must be reviewed.

[12] $SCCR = \frac{SCC_{GF}}{SCC_{EC}}$ where SCCEC = short circuit contribution of EC to a 3Φ fault at the high side of the distribution transformer connected to GF exclusive of other GFs. SCCGF = short circuit contribution of GF to a 3Φ fault at the high side of the distribution transformer connected to GF (symmetrical, based on sub-transient reactance).

Supplemental Review

If there are concerns related to islanding the following flow chart is applied [81]:

**IF**

1. Applicant GF is Non-Exporting

**OR**

2. GF is Certified Non-Islanding

**AND**

3. The Aggregate Generation does not exceed 15% of the Line Section peak load

**OR**

4. Other installed GF on the circuit are not Synchronous machines

**AND**

5. The Aggregate Generation does not exceed 15% of the line segment peak load

**OR**

6. The Applicant GF Technology does not includes synchronous machines

**OR**

7. All of the other GFs are Non-Export

**AND**

8. The capacity of the Applicant GF does not exceed 10% Line Section peak load

**THEN**

Application does not present a potential islanding concern, skip to the next issue.

**OTHERWISE**

Application presents a potential islanding concern; continue review using guidance in other sections of the guideline.

If there are concerns related to voltage regulation the following flow chart is applied [81]:

**IF**

1. Applicant GF peak Export does not exceed 200kW

**AND**

2. The Aggregate GF Peak Export does not exceed 15% of the Line Section peak load

**OR**

3. The Applicant GF is non-exporting

**AND**

4. Voltage Regulation on the line section (Q7) is not controlled by a Line Regulator or voltage-controlled switched Capacitor bank

**OR**

5. Applicant GF Capacity does not exceed 500 kW

**THEN**

Application does not present a potential Voltage Regulation concern, skip to the next issue

**OTHERWISE**

Application presents a potential Voltage Regulation concern; continue review using guidance in the following sections

Potential solutions - Voltage regulation [81]: If feeder reverse current flow through uni-directional voltage regulation equipment is anticipated, equipment modification or replacement may be warranted. Control schemes on some GFs may be set up to provide voltage support, sourcing or sinking VARs as directed, or to make the generation “voltage neutral” by sinking VAR’s to offset power export:

- replace/upgrade voltage regulating equipment.
- replace/upgrade line capacitors or controls reconfigure Line Section.

If there are concerns related to short circuit current the following flow chart is applied[13] [81]:

**IF**

1. The APPLICANT SCCGF is less than the existing EQUIPMENT RATING MARGINS

**OR**

2. Dedicated Transformer is True

**AND**

3. The AGGREGATE SCCGF is less than 5 % of the EC Substation SCC

**AND**

4. The AGGREGATE SCCGF is less than 10 % of the EQUIPMENT RATINGS

**OR**

5. The APPLICANT SCCGF is less than 5 % of the AGGREGATE SCCGF

**THEN**

Application does not present a potential concern with respect to equipment short circuit rating, skip to the next issue.

**OTHERWISE**

A Fault Study is necessary to determine if any equipment ratings are exceeded.

Potential solutions - Short-circuit current [81]:

- Replace/upgrade Distribution System elements.
- Applicant Install current limiting devices (fuses, reactors).
- Reconfigure the circuit to redistribute the generation with respect to the affected equipment.
- Replace/upgrade underrated neighboring customer equipment.

It is worth mentioning that the above described technical methodology is to be reformed by a more advanced one for setting transparent rules that provide a clearer and predictable path to interconnection for distributed generation while maintaining the safety and reliability of the electric grid. According to the new advanced Rule 21 the following flow chart is proposed [82]:

[13] $SCCR = \frac{SCC_{GF}}{SCC_{EC}}$ where SCCEC = short circuit contribution of EC to a 3Φ fault at the high side of the distribution transformer connected to GF exclusive of other GFs. SCCGF = short circuit contribution of GF to a 3Φ fault at the high side of the distribution transformer connected to GF (symmetrical, based on sub-transient reactance).

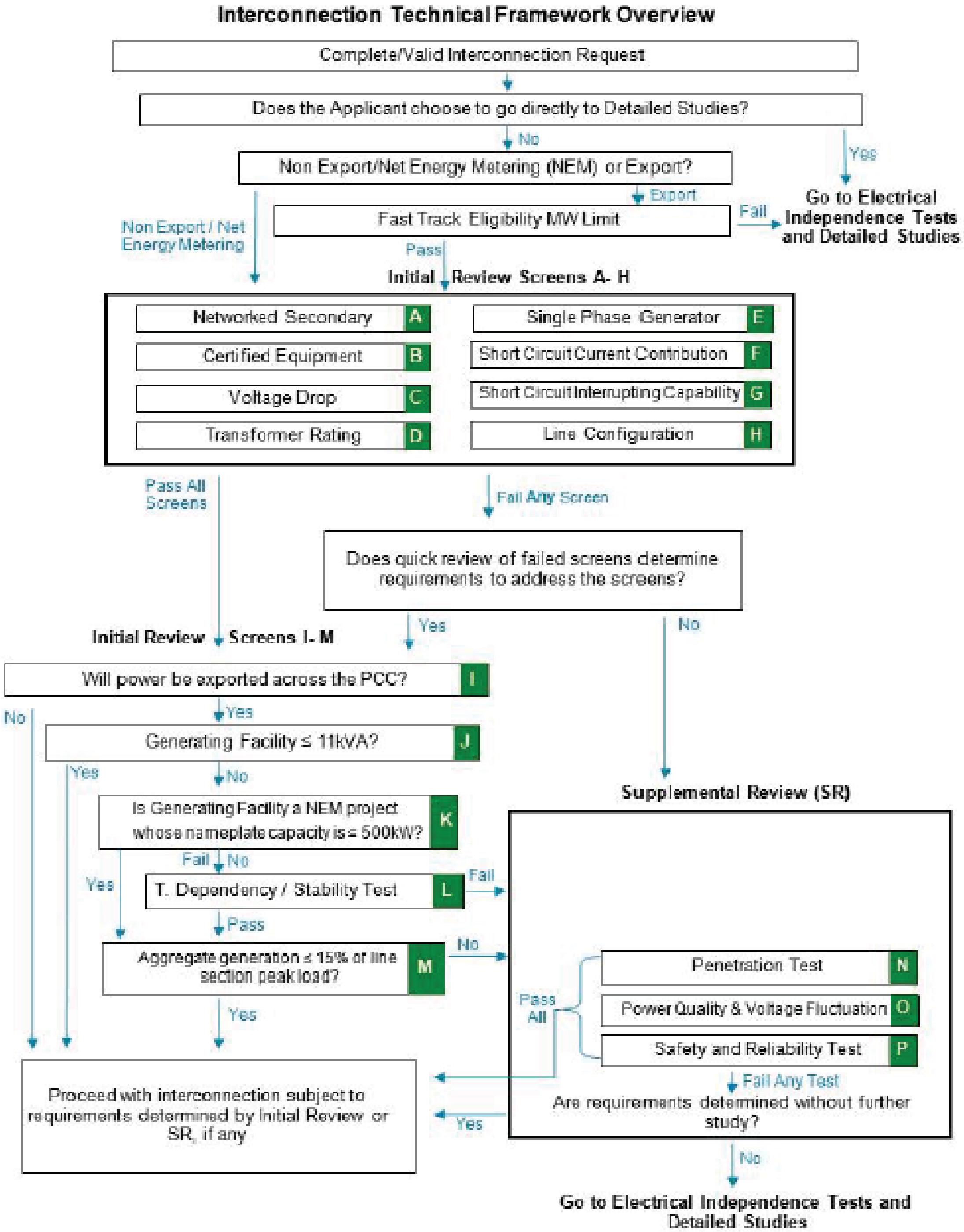



**Fig. 31a Initial and Supplemental Review screens (USA - California)** [82]

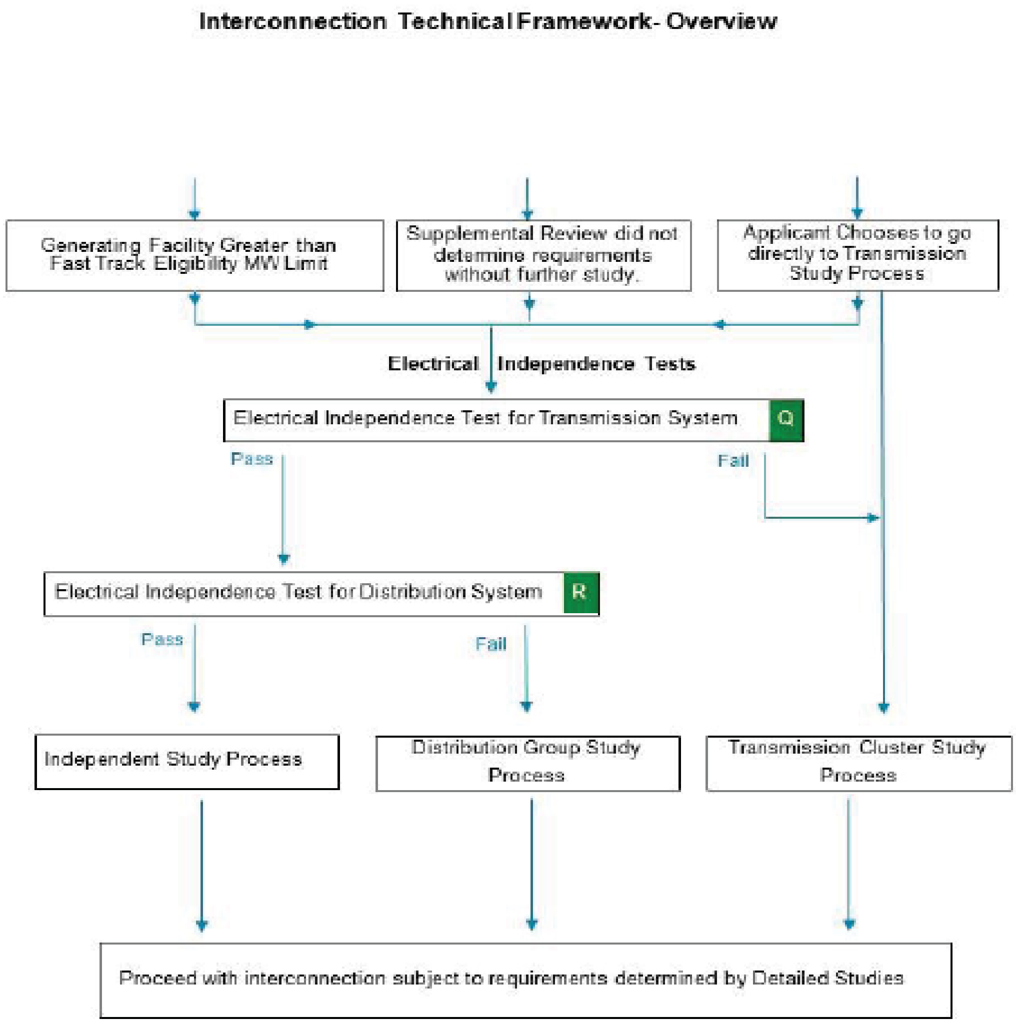



**Fig. 31b Detailed Study screens (USA - California)** [82]

The previous flow charts consist of Initial Review Screens (Fig. 31a), Supplemental Review Screens (Fig. 31a) and Detailed Study Screens (Fig. 31b) [82].

**Initial Review Screens** [82]**:** Include thirteen Initial Review Screens (Screens A-M). The Initial Review Screens include the eight screens that are presently contained in the existing Rule 21 tariff. These existing screens are included in the Revised Tariff as Screens A, B, C, F, H, I, J, and M. The other five screens are either derived from existing federal interconnection procedures or are being introduced as new screens. Screens E (Single Phase Generator), G (Short Circuit Interrupting Capability) and L (Transmission Dependency/Stability) mirror technical review screens included in FERC's SGIP[14]. The SGIP language has been augmented in Screen M to focus on the absence or presence of potential interdependencies with the state's transmission system. This screen identifies when an interconnection request may require review by CAISO[15], or at the least, coordination with the CAISO in processing the interconnection request. Screens D (Transformer Rating) and K (NEM Projects ≤ 500kW) are new screens. Screen D has been added to allow a distribution provider to assess potential secondary transformer or secondary conductor overloads and determine when it may be necessary to change a transformer or conductor to facilitate the safe and reliable interconnection of a generating facility without diminishing the power quality supplied to nearby retail customers. Screen K has been added to facilitate interconnection of NEM facilities up to 500 kW in

[14] Small Generator Interconnection Procedure
[15] California Interdependent System Operator

capacity, by allowing such facilities to bypass Screen M. The use of nameplate capacity in Screen K expedites the Initial Review analysis and enables a distribution provider to better achieve its statutory timeframes for interconnecting NEM systems.

**Supplemental Review Screens** [82]**:** Supplemental Review screens are a new addition to the Revised Tariff. Screens N (Penetration Test), O (Power Quality and Voltage Tests) and P (Safety and Reliability Tests) allow a distribution provider to assess projects under Fast Track review despite failure of an Initial Review screen. The introduction of these new screens is intended to provide more transparency and certainty with regard to the analysis conducted in Supplemental Review. At present, supplemental review in the existing Rule 21 tariff is largely an internal business practice at each utility, which can create cost and timing uncertainty for developers.

**Detailed study screens** [82]**:** The three Detailed Study processes are intended to apply the most appropriate level of review based on a project's interdependencies. The Detailed Study screens assess the interdependency between a project and the transmission system (Screen Q) and between a project and other distribution-level projects queued before it (Screen R). Projects that pass both screens will proceed through the Independent Study Process. Projects that fail Screen Q will proceed to the Transmission Cluster Study. Projects that fail Screen R will proceed to the Distribution Group Study.

In more detail:

**Initial Review Screens** [82]

- Screen D: Do the maximum aggregated Gross Ratings for all the Generating Facilities connected to a secondary distribution transformer exceed the transformer or secondary conductor rating, modified per established Distribution Provider practice, absent any customer generators?
  This screen addresses potential secondary transformer or secondary conductor overloads. When Distribution Provider's analysis determines a transformer or conductor, change is required. Distribution Provider will furnish Applicant with an explanation of why the change is needed.

- Screen E: If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, does it cause unacceptable imbalance between the two phases of the 240 volt service?
  Generating Facilities connected to a single-phase transformer with 120/240 V secondary voltage must be installed such that the aggregated gross output is as balanced as practicable between the two phases of the 240 volt service. When Distribution Provider's analysis determines a transformer change is required. Distribution Provider will furnish the customer with an explanation of why the change is needed.

- Screen G: Does the proposed Generating Facility, in aggregate with other generation on the distribution circuit, cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Request equipment on the system to exceed 87.5% of the short circuit interrupting capability;
  Or is the Interconnection proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability?
  This Screen does not apply to Generating Facilities with a Gross Rating of 11 kVA or less. If the Generating Facility passes this screen, it can be expected that it will not cause any of Distribution Provider's equipment to be overstressed.

Screen K: Is the Generating Facility a Net Energy Metering (NEM) Generating Facility with nameplate capacity less than or equal to 500kW?
The purpose of this Screen is solely to facilitate interconnection of NEM facilities below this size threshold by allowing such facilities to bypass Screen M. The use of nameplate capacity expedites the Initial Review analysis. In Supplemental Review, the net export will be analyzed.

Screen L: Is the Interconnection Request for an area where: (i) there are known, or posted, transient stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to Distribution Provider, with earlier queued Transmission System interconnection requests?
Where (i) or (ii) above are met, the impacts of this Interconnection Request to the Transmission System may require Detailed Study. Special consideration must be given to those areas identified as having current or future (due to currently queued interconnection requests) grid stability concerns.

**Supplemental Review Screens** [82]

- Screen N (Penetration Test): Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate Generating Facility capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility?
  The type of generation will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar generation systems with no battery storage use daytime minimum load (i.e. 10 am to 4 pm for fixed panel systems and 8 am to 6 pm for PV systems utilizing tracking systems), while all other generation uses absolute minimum load. Penetration of Generating Facility installations that does not result in power flow from the circuit back toward the substation will have a minimal impact on equipment loading, operation, and protection of the Distribution System.

- Screen O (Power quality and Voltage Tests): In aggregate with existing generation on the line section,
  1. Can it be determined within the Supplemental Review that the voltage regulation on the line section can be maintained in compliance with Commission Rule 2 and/or Conservation Voltage Regulation voltage requirements under all system conditions?
  2. Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE1453?
  3. Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the Point of Common Coupling (PCC)?

- Screen P (Safety and Reliability Tests): Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without Detailed Study?
  In the safety and reliability test, there are several factors that may affect the nature and performance of an Interconnection (i.e. unique system topology, generation energy source etc). The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:
  1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (i.e. several large commercial customers)?
  2. Is there an even or uneven distribution of loading along the feeder?
  3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (i.e. 600A class cable)?
  4. Does the Generating Facility incorporate a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time?
  5. Is operational flexibility reduced by the proposed Generating Facility, such that transfer of the line section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues?
  6. Does the Generating Facility utilize Certified anti-islanding functions and equipment?

**Detailed Study Screens** [82]

- Screen Q: Is the Interconnection Request electrically Independent of the Transmission System? Distribution Provider, in consultation with the CAISO, will determine, based on knowledge of the interdependencies with earlier-queued interconnection requests under any tariff, whether the Interconnection Request to the Distribution System is of sufficient MW size and located at a point of interconnection such that it is reasonably anticipated to require or contribute to the need for Network Upgrades. NEM Generating Facilities with net export less than or equal to 500 kW that may flow across the Point of Common Coupling into Distribution Provider's will not be studied in the Transmission Cluster Study Process, but may be studied under the Independent Study Process.

- Screen R: Is the Interconnection Request independent of other earlier-queued and yet to be studied interconnection requests interconnecting to the Distribution System?
  Distribution Provider may conduct incremental power flow, aggregate power flow, and/or short-circuit duty tests using existing interconnection studies, Base Case data, overall system knowledge, and engineering judgment to determine whether an Interconnection Request can be studied independently of earlier-queued interconnection requests.

**Independent Study Process Interconnection Studies** [82]**:** The Interconnection Studies shall consist of an Interconnection System Impact Study and an Interconnection Facilities Study. The Interconnection Studies will identify Interconnection Facilities, Distribution Upgrades and Reliability Network Upgrades necessary to mitigate thermal overloads and voltage violations, and address short circuit, stability, and reliability issues associated with the requested Interconnection Service.

**Massachusets**

There are three basic paths for interconnection of the Interconnecting Customer's Facility in Massachusetts. They are described below and detailed in Fig. 32 and 33 with their accompanying notes. Unless otherwise noted, all times in the Interconnection Tariff reference Company business days under normal work conditions [83].

1. **Simplified** – This is for Listed inverter-based Facilities with a power rating of 10 kW or less single phase or 25 kW or less three-phase depending on the service configuration, and located on radial EPSs where the aggregate Facility capacity on the circuit is less than 7.5% of circuit annual peak load qualify for Simplified interconnection. A Listed inverter-based Facility with a power rating of 15 kW or less single phase located on a spot network EPS under certain conditions would also be eligible.

2. **Expedited** –Other Interconnecting Customers (Listed Facilities) not qualifying for the Simplified Process or not in the Standard Process must pass a series of screens before qualifying for Expedited interconnection.

3. **Standard** – This is for all facilities not qualifying for either the Simplified or Expedited interconnection processes on radial and spot network EPSs, and for all Facilities on area network EPSs.

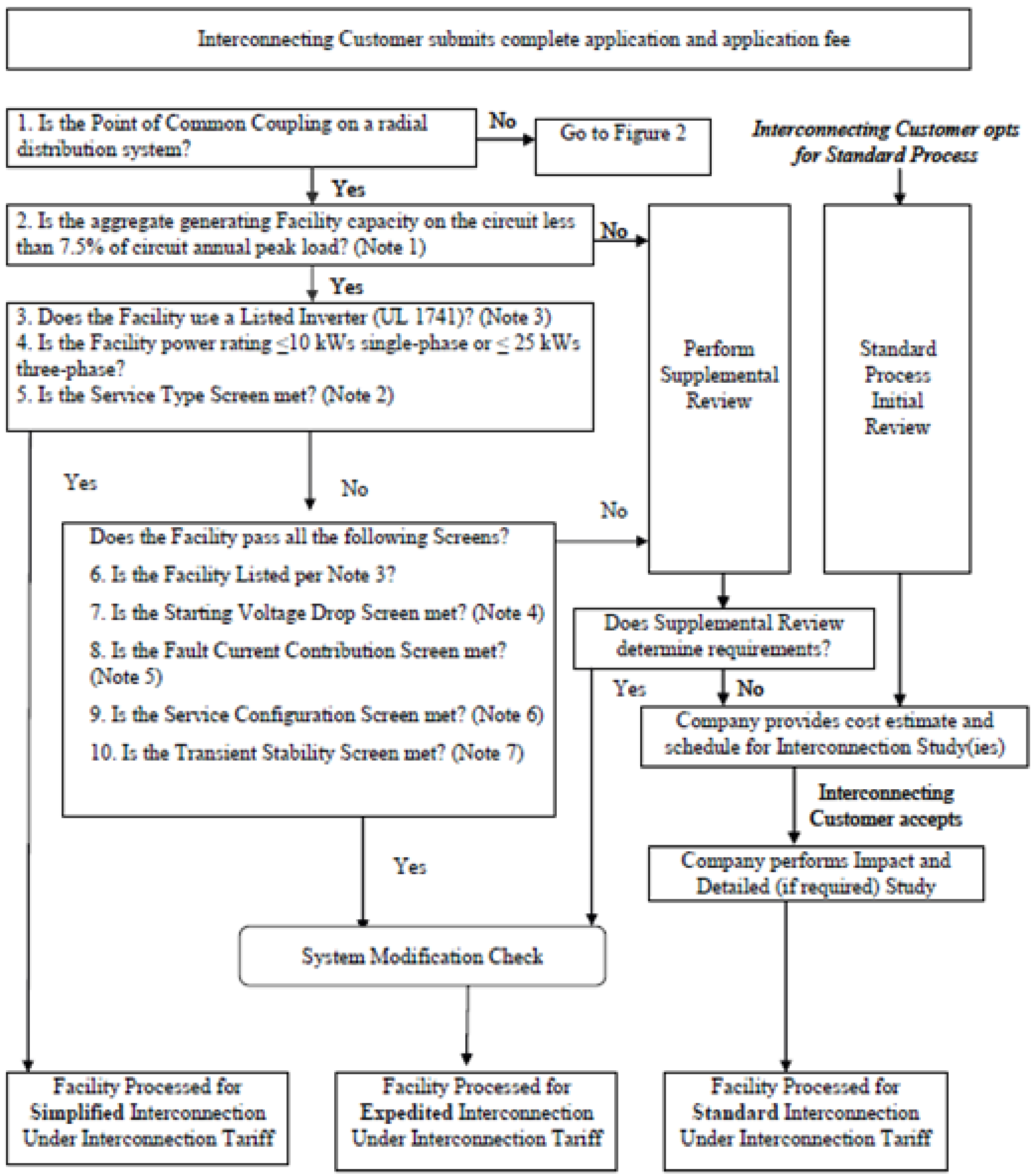



**Fig. 32 Schematic of Massachusetts DG Interconnection Process (USA - Massachusets)** [83]

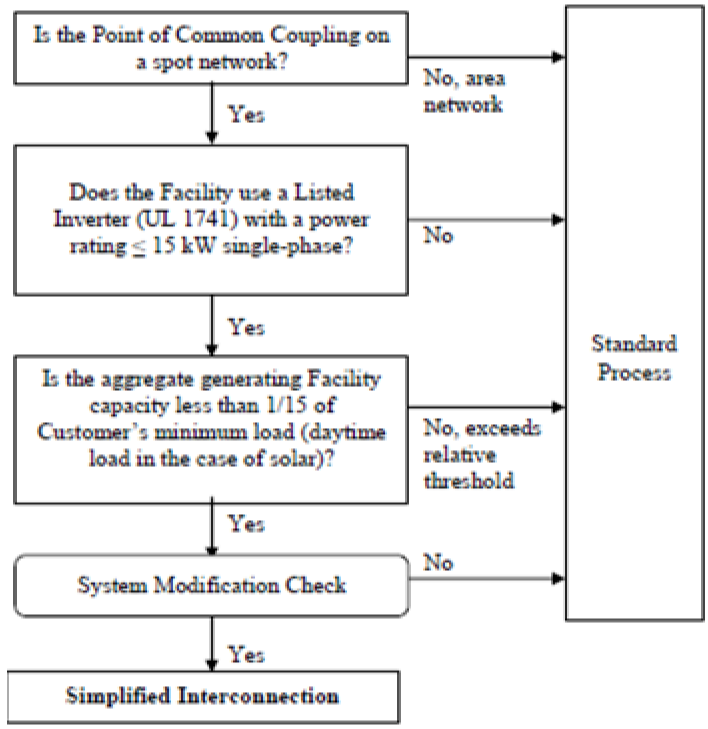



**Fig. 33 Simplified Interconnection to Networks (USA - Massachusets)** [83]

**<u>Notes</u>** [83]**:**

**Note 1:** On a typical radial distribution EPS circuit ("feeder") the annual peak load is measured at the substation circuit breaker, which corresponds to the supply point of the circuit. A circuit may also be supplied from a tap on a higher-voltage line, sometimes called a subtransmission line. On more complex radial EPSs, where bidirectional power flow is possible due to alternative circuit supply options ("loop service"), the normal supply point is the loop tap.

**Note 4:** This Screen only applies to Facilities that start by motoring the generating unit(s) or the act of connecting synchronous generators. The voltage drops should be less than the criteria below. There are two options in determining whether Starting Voltage Drop could be a problem. The option to be used is at the Company's discretion:

- **Option 1:** The Company may determine that the Facility's starting inrush current is equal to or less than the continuous ampere rating of the Facility's service equipment.
- **Option 2:** The Company may determine the impedances of the service distribution transformer (if present) and the secondary conductors to the Facility's service equipment and perform a voltage drop calculation. Alternatively, the Company may use tables or nomographs to determine the voltage drop. Voltage drops caused by starting a generating unit as a motor must be less than 2.5% for primary interconnections and 5% for secondary interconnections.

**Note 5:** The purpose of this Screen is to ensure that fault (short-circuit) current contributions from all Facilities will have no significant impact on the Company's protective devices and EPS. All of the following criteria must be met when applicable:

a. The proposed Facility, in aggregation with other generation on the distribution circuit, will not contribute more than 10% to the distribution circuit's maximum fault current under normal operating conditions at the point on the high voltage (primary) level nearest the proposed PCC.
b. The proposed Facility, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or Interconnecting Customer equipment on the EPS to exceed 85% of the short-circuit

interrupting capability. In addition, the proposed Facility will not be installed on a circuit that already exceeds 85% of the short-circuit interrupting capability.

c. When measured at the secondary side (low side) of a shared distribution transformer, the short-circuit contribution of the proposed Facility must be less than or equal to 2.5% of the interrupting rating of the Company's service equipment.

Coordination of fault-current protection devices and systems will be examined as part of this Screen.

**Note 6:** This Screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over voltages on the Company EPS due to a loss of ground during the operating time of any anti-islanding function.

**Table 19: Simplified description of Note 6** [83]

| Primary Distribution Line Type | Type of Interconnection to Primary Distribution Line | Result/Criteria |
|---|---|---|
| Three-phase, three wire | 3-phase or single phase, phase-to-phase | Pass Screen |
| Three-phase, four wire | Effectively-grounded 3 phase or single-phase, line-to-neutral | Pass Screen |

If the proposed generator is to be interconnected on a single-phase transformer shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kilovolt-ampere ("kVA").

If the proposed generator is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.

**Note 7:** The proposed Facility, in aggregate with other Facilities interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the Facility proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., 3 or 4 transmission voltage level buses from the PCC).

**<u>Texas</u>**

In Texas the [84] is applied for the DG interconnection to the network. This manual describes in depth the requirements, the assessment of the impact of DG on the network and the criteria that are used in order for the Operator to approve an interconnection with or without both study fee and new connection works. According to this general policy that is applied, the following cases are emphasized.

If the proposed site is not on a networked secondary, no study fee may be charged to the applicant if all of the following apply [84]:

- Proposed DG equipment is pre-certified.
- Proposed DG capacity is 500kW or less.
- Proposed DG is designed to export no more than 15% of the total load on feeder (based on the most recent peak load demand).
- Proposed DG will contribute not more than 25% of the maximum potential short circuit current of the feeder.

A flow chart of this case is shown on the following figure [84].

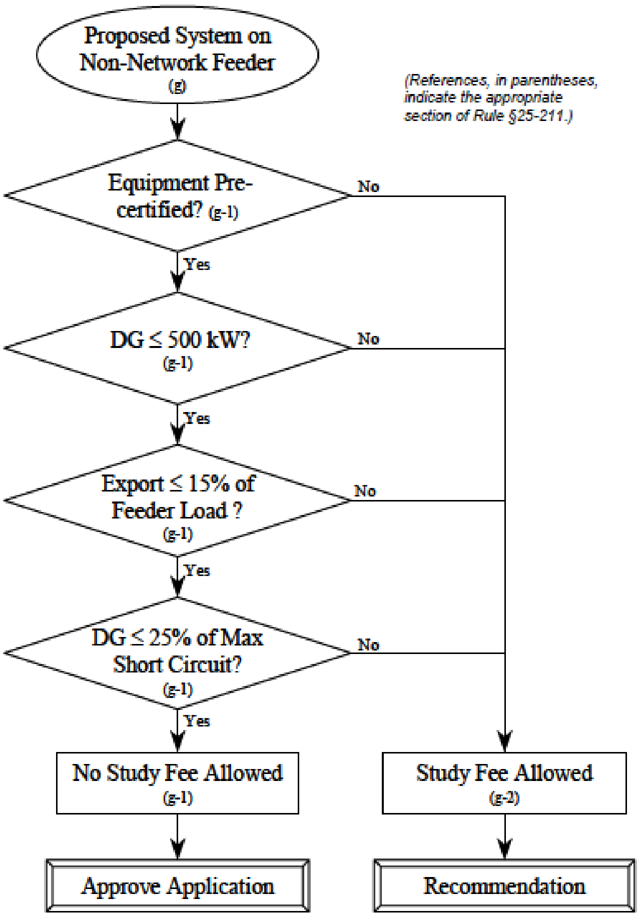



**Fig. 34 Flow chart of interconnection process (USA - Texas)** [84]

**Note 1:** If the DG capacity is less than or equal to 500 kW, the review can continue to the export level review. If the DG capacity, as reported on the completed application, exceeds the 500 kW threshold, the TDU is allowed up to four weeks to perform a study that may involve a fee [84].

**Note 2:** A key question for each DG installation is whether the DG applicant intends to export generation across the point of common coupling (PCC); and if so, how much. If power is to be exported across the PCC [84]:

- DG that exports can cause reverse voltage drops (from the DG towards the substation). Thus, the TDU may need to study the local distribution system and determine if adjustments to local voltage regulation schemes are necessary.
- Protection against the formation of unintended islands becomes more complicated since the DG will be supporting load beyond the PCC.

Rule §25.211 (g)(1) provides a threshold to address these concerns, stated as 15% of the total load on a single radial feeder. Here again, total load is defined as the maximum load over the previous 12–month period. This threshold, expressed in equation form, is the following:

$$DGexport_{max} \leq 0.15 \times FeederLoad_{max} \quad (7)$$

This is the value at or below which the DG can export without requiring costly changes to the TDU system in order to accommodate the DG export. If the system falls within the export limit, it is assumed that the application of the DG on that portion of the distribution system will not cause the complications listed above. DG which exceeds this threshold may be studied to determine whether it could cause islanding or adverse power flows.

**Note 3:** If the DG passes the export level threshold of 15% of feeder load, the maximum short circuit current on the radial feeder must be calculated. The TDU will then calculate the maximum short circuit current contribution at the DG location. Once this value is determined, multiply that quantity by 0.25 to establish the 25% threshold for the primary feeder. The DG's maximum short circuit capability found in the application must then be converted to the corresponding short circuit current after transforming to primary voltage. This transformed DG short circuit must be less than or equal to the 25% threshold. This threshold is expressed through the following equations [84]:
Assume:

$$FeederShortCircuit_{max} = FSC_{max} \quad (8)$$

and:

$$DGShortCircuit_{max} = MaxDGShortCircuit \times DGOutputVoltage \div PrimaryVoltage = DGSC_{max} \quad (9)$$

To comply with this threshold, DGSCmax must be less than or equal to 25% of FSCmax:

$$DGSC_{max} \leq 0.25 \times FSC_{max} \quad (10)$$

If the DG complies with this threshold, it is assumed that:

- the DG has little impact on the distribution system's short circuit duty.
- the DG will not adversely affect the fault detection sensitivity of the distribution system.
- the utility's relay coordination and fuse-saving schemes are not significantly impacted.

If the DG does not comply with this threshold, the TDU may study the DG application over four weeks with a study fee. If the DG passes all these thresholds, it will not require changes to the utility system to accommodate the installation. Such DG will not require additional studies or equipment to accommodate, and can interconnect without any study fees.

Certain aspects of secondary network systems create technical difficulties that may make interconnection more costly to implement. If the proposed site is serviced by a networked secondary, no study fee may be charged to the applicant if [84]:

- Proposed DG equipment is pre-certified.
- Aggregate DG, including the proposed system, represents 25% or less of the total load on the network (based on the most recent peak load demand).

and either

- Proposed DG has inverter-based protective functions, or
- Proposed DG rating is less than the local applicant's verifiable minimum load.

A flow chart of this case is shown on the following figure [84].

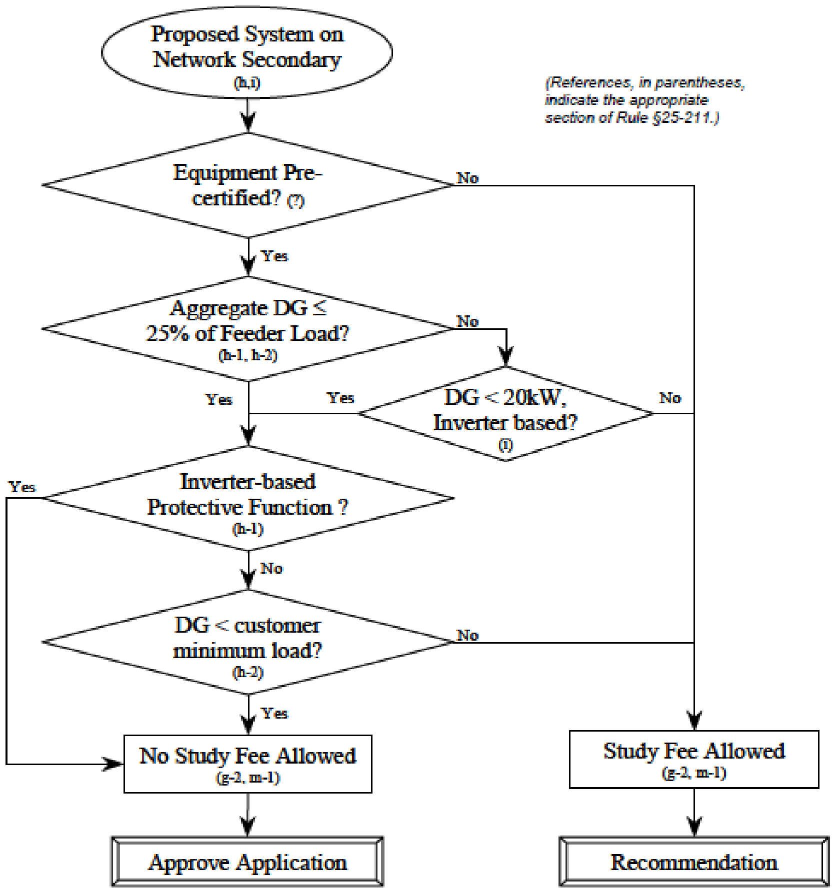



**Fig. 35 Flow chart of interconnection process in LV networks (USA - Texas)** [84]

**Note 1**: The aggregate DG is determined by summing the nameplate ratings of each of the DG units within the network. The total load of the network is defined as the maximum load of the network for the previous 12-month period. This threshold, expressed in equation form, is the following [84]:

$TotalDGCapacity_{network} = TDGC_{network} \leq 0.25 \times TotalLoad$ (11)

This is the value at or below which inverter-based DG should not require costly changes to the utility system in order to accommodate the DG installation. The TDU shall accept applications, and a study fee may not be charged since it is assumed that no study is necessary. It is assumed that all inverter-based DG under 20kW is so small that, irrespective of the 25% threshold, no study is necessary and therefore the application shall be accepted and no study fee may be charged.

**Note 2**: All export systems on network secondaries may be subject to a study for which a fee may be charged (excluding inverter-based systems). To ensure no export of power without the use of explicit non-export protective functions, the capacity of the DG must be no greater than the customer's verifiable minimum annual load. Use of additional anti-islanding functions may be required to ensure worker and equipment safety [84].

**Note 3:** As the total DG on a secondary network grows relative to total network load, so does the likelihood of reverse power flow through one or more network protectors causing them to open and interrupt service. In this case, power flow studies may be needed to determine if it is possible for the network protectors to see reverse power (even momentarily) from the DG and initiate a trip. If the power flow study determines that the DG installation could cause unintended operation of the network protector, one way to mitigate this problem is to switch the DG facility service to a radial service. If the proposed DG location is close to a network protector, it might be easy to switch the DG onto a radial feeder, making the change less costly. If the 25% of network load requirement is not met, the utility should conduct a power flow study and investigate whether it is necessary to convert the DG service from network to radial to mitigate the unintended operation of the network protectors [84].

The above two main decision paths result in either "Approve Application" or "Recommendation". Systems meeting the requirements that result in "Approve Application" are considered simple with little chance of being a hazard to the distribution system, personnel, or neighboring customers. These systems should not require any additional studies, thus the utility is not allowed to charge a study fee. The Recommendation results from a study that may be charged to the applicant, and may be one of the following [84]:

- Approval of the application as it is.
- Description of changes to the proposed DG system or to the distribution system necessary to approve the application.
- Rejection of the application due to specified reasons.

## Japan

In Japan, the most common technical requirements for grid connection of DER can be categorized as follows:

- Technical Requirements Guidelines of Grid interconnection to Secure Electricity Quality [85], which define the most basic requirements for the grid connection of DER and were enacted in 2004 by the Agency for Natural Resources and Energy in the Japanese Government.
- Grid-interconnection code [86], which outlines the technical requirements for connecting DER to the different voltage levels of distribution network, like LV:<600V, HV:600V-7kV, and SNW (Spot Network) or Special HV (SHV):>7kV.
- The Harmonic Restraint Guidelines for HV or SHV Consumers [87], which specifies the power quality regulations relating to the harmonics and were enacted in 2004 by the Nuclear and Industrial Safety Agency of Ministry of Economy, Trade and Industry (METI) of Japan. These guidelines require that the DERs connected to HV/SHV take measures to reduce harmonic outflow current below prescribed values, i.e., below 5% in HV (6.6kV) lines and less than 3% in SHV lines.
- The Rules of Electric Power System Council of Japan (ESCJ) [88], which provides the general rules for connecting DER to the distribution network of different voltages. The rules were made effective from June 19, 2012 by ESCJ.

Apart from the above guidelines, codes and regulations, the detailed rules at each DER grid connection are decided through mutual agreement between the parties involved.

**Type of distribution networks**

*LV network*

In general, a single-phase two-wire: 100V, a single-phase three-wire: 100V/200V, three-phase three-wire: 200V, and three-phase four-wire: 100V/200V, are most common LV distribution networks in Japan.

*HV network*

In general, the three-phase three-wire: 6.6kV is a main HV distribution network in Japan.

*SNW network*

In general, SNW represent a spot network with two or more 22kV or 33kV lines operating in parallel.

*SHV network*

The special high voltage (SHV) network consists of line with more than 7kV, and is usually used to supply power to the high-voltage customers. Incidentally, when the voltage is 35kV below or below and it is treated as a distribution network.

**Voltage level for DER connection**

The voltage level for DER connection is determined using the following Table 20:

**Table 20: Maximum Capacity for a single DER connection at different voltage levels (Japan)**

| Maximum Capacity | Connection Voltage Level | Rules & Regulations |
|---|---|---|
| P≦2kVA | LV single phase (<600V) (Typically 100V) | Grid-interconnection Code JEAC 9701 – 2012 by Japan Electrotechnical Standards & codes committee |
| P≦6kVA | LV single phase (<600V) (Typically 200V) | |
| P<50kW | LV three phase (<600V) (Typically 200V) | |
| P<2000kW | HV three phase (600V-7kV) (Typically 6.6kV) | |
| P<10000kW | SNW three phase ( >7kV) (Typically 22kV/33kV) | |
| P>2000kW | SHV three phase (>7kV) (Typically 66kV/77kV or higher) | |

**Technical requirements for DER connection**

The main technical requirements for DER connection are summarized in Table 21:

**Table 21: Technical requirements for DER (Japan)** ○: Applicable -: Not applicable

| Description | | Technical Requirements | Network Type | | | |
|---|---|---|---|---|---|---|
| | | | LV | HV | SNW | SHV |
| Power factor(pf) | Common | ≧85% lagging and leading pf not allowed (Network) | ○ | ○ | ○ | ○ |
| | Reverse flow | ≧85% (Source using control) *1<br>≧95% (Source using no control) | ○ | ○ | - | *2 |
| | No reverse flow | ≧95%(Inverter connected source) | ○ | - | - | - |
| Protection | Common | OVR/UVR | ○ | ○ | ○ | ○ |
| | | DSR/OVGR*3 | ○ | ○ | - | ○ |
| | Reverse flow | OFR/UFR/Islanding detection device | ○ | ○ | - | ○ |
| | No reverse flow | UFR/RPR/UPR/Reverse flow detection/Islanding detection device *4 | ○ | ○ | ○ | ○ |
| | Fault prevention during reclosing | No line voltage detection device *5 | - | ○ | - | ○ |
| | Controllable source/demand | Load shedding in the event of overloading of feeder/transformer due to generator trip*6 | - | ○ | ○ | ○ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Miscellaneous | | No switching during non energized network and no switching for a certain period once the network supply restored | ○ | - | - | - |
| | | | Reverse flow not allowed (transformer level) | - | ○ | - | - |
| Voltage fluctuation | Voltage fluctuation due to reverse flow or generator trip | | To control voltage automatically to maintain the voltage on LV side within 101±6V, 202±20V | ○ | ○ | - | - |
| | Voltage fluctuation due to generator trip/connection | | To keep voltage within 1 -2% of normal value by automatic load reduction *7 | - | - | ○ | - |
| | | | To keep voltage within 1 -2% of normal value by voltage auto control measures | - | - | - | ○ |
| | Synchronous generator | | Equipped with a damping winding and automatic synchronism indicator | ○ | ○ | ○ | ○ |
| | Induction generator | | If voltage deviation exceeds 10% of normal value at connection, the current limiting reactor need to be installed | ○ | ○ | ○ | - |
| | | | If voltage deviation exceeds 2% of normal value during connection, the current limiting reactor need to be installed | - | - | - | ○ |
| | Inverter type generator | Self excited | Equipped with an automatic synchronism function | ○ | ○ | ○ | ○ |
| | | Line excited | If voltage deviation exceeds 10% of normal value at connection, the current limiting reactor need to be installed *8. | ○ | ○ | - | - |
| | | | If voltage deviation exceeds 2% of normal value during connection, the current limiting reactor need to be installed*9 | - | - | - | ○ |
| | Wind generator | | If voltage problems (flickers etc.) caused by output fluctuation or frequent connection/disconnection *10 | ○ | ○ | - | ○ |
| Short circuit capacity | Generator | | Installing current limiting reactors etc. not to exceed the instantaneous short circuit current limits of equipment like Circuit Breaker (CB), lines etc *11. | ○ | ○ | ○ | ○ |
| Islanding | Reverse flow | | Islanding not allowed | ○ | ○ | ○ | - |
| | | | Islanding allowed with OFR & UFR or with a telecommunication to operate CB | - | - | - | ○ |
| | No reverse flow | | Islanding not allowed | ○ | ○ | ○ | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | Islanding allowed with OFR & UFR or RPR to prevent Islanding | - | - | - | ○ |
| Prevention of unnecessary disconnection | Measures depending on Voltage dip & its duration | Refer to Fault Ride Through (FRT) conditions | ○ | ○ | - | - |
| | | In case of SNR network line fault, no disconnection of source & to continue supply by disconnecting faulty line | - | - | ○ | - |
| | | In case of remote grid fault, no disconnection of SNR | - | - | ○ | - |
| | | In case of remote grid fault, HV/SHV networks need not to be unnecessarily disconnected due to short transients. | - | ○ | - | ○ |

*1: In the extreme case when the voltage becomes very high, it is possible to allow power factor up to 80%.

*2: In case of SHV, the power factor should be maintained at a level, so that the network voltage stays within a proper limit.

*3: DSR is required except SNR networks and can be waived off under some conditions. OVGR is only required in case of HV/SHV networks, but it can be waived off under certain conditions. OVR : Over voltage relay, UVR : Under voltage relay, OVGR : Over voltage grounding relay, DSR: Directional short circuit relay

*4: In case of inverter type source, either islanding detection device or UFR, RPR and reverse flow detecting device are needed in LV networks. Also, in case of ac source (synchronous, induction generator), islanding detection device, UFR, RPR and reverse flow detecting device are needed in LV networks. RPR and UFR are generally needed in HV and SNR networks. In case of SHV, RPR is needed only if the detection is not possible with OFR/UFR.OFR: Over frequency relay, UFR: Under frequency relay, RPR: Reverse power relay, UPR: Under power relay, OFR: Over frequency relay.

*5: It is possible to omit it depending upon the conditions.

*6: In case of SHV with 100kV, the curtailment of generator output by detecting the overload conditions.

*7: In case load reduction or other voltage regulating methods to control LV voltage within specified limits do not work, the enforcement of LV feeders needs to be implemented.

*8: In case the current limiter or other measures do not work, the adoption of self excited type or the enforcement of LV feeders needs to be implemented.

*9: In case the current limiter or other measures do not work, the adoption of self excited type needs to be implemented.

*10: In case the voltage problems are not solved in spite of some measures, the enforcement of distribution/transmission lines or adoption of grid connection using exclusive lines, need to be implemented.

*11: In case LV network, it is applicable only for ac source (generators).

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### Fault Ride Through (FRT) requirements for DER in Japan

The Japanese Government set a target for installing 28GW of PV systems by 2020, and 53 GW of PV systems by 2030 for coping with the global environmental issues These PV systems are expected to be connected to the electric grid and these systems may stop the operation or not able to operate stably in case of grid transients such as voltage sag or so on. This aspect may impact the grid stability adversely under the large PV penetration. In Japan, the fault ride through (FRT) requirements under voltage sag and frequency fluctuation for DER especially for PV systems connecting to single phase LV distribution network were recently investigated and proposed by the Japan Electrotechnical standards and codes committee (JESC). The FRT requirements for single phase PV system for connecting to LV networks were completed in August 2011 and for three phase PV systems and wind power generation systems were completed in August 2012. The FRT requirements for single phase battery, fuel cell and gas engine system were completed in March 2013. In this report, the FRT for PV systems are covered and shown in Table 22, Table 23 and Table 24.

**Table 22: FRT requirements for single phase PV systems (Japan)**

| Details | LVRT Level | Voltage sag period | Operational Requirements | | | |
|---|---|---|---|---|---|---|
| | | | (Residual Voltage ≥ LVRT level) | | (Residual Voltage < LVRT level) | |
| Up to March 2017 | 30% | 1.0[s] | (≤1[s]) Continue operating | (≥1[s]) Disconnection from Grid | (≤1[s]) Gate Block or continue operating | (≥1[s]) Disconnect from Grid |
| From April 2017 onwards | 20% | 1.0[s] | (≤1[s]) Continue operating | (≥1[s]) Disconnection from Grid | (≤1[s]) Gate Block or continue operating | (≥1[s]) Disconnect from Grid |

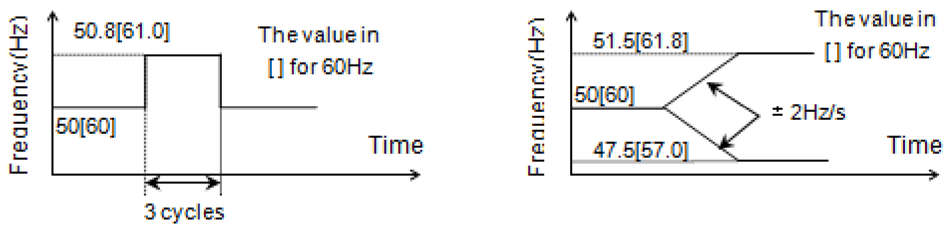
**Table 23: FRT requirements for three phase PV systems (Japan)**

| Details | LVRT level | Voltage sag period | Operational Requirements | | | |
|---|---|---|---|---|---|---|
| | | | (Residual Voltage ≧LVRT level) | | (Residual Voltage < LVRT level) | |
| Currently | 70～30% | 0.3～1.0[s] | Disconnecting in the event of grid abnormality | | | |
| April 2014～March 2017 | 30% | 0.3[s] | (≤0.3[s]) Continue operating | (≥0.3[s]) Disconnection from Grid | (≤0.3[s]) Gate Block or continue operating | (≥0.3[s]) Disconnect from Grid |
| April 2017 onwards | 20% | 0.3[s] | (≤0.3[s]) Continue operating | (≥0.3[s]) Disconnection from Grid | (≤0.3[s]) Gate Block or continue operating | (≥0.3[s]) Disconnect from Grid |

**Table 24: FRT requirements for the PV output restoration (Japan)**

| Details | LVRT level | PV Output on Voltage Restoration | |
|---|---|---|---|
| | | （Residual Voltage ≥ LVRT level） Connected & continue operating | （Residual Voltage <LVRT level） Disconnection form grid |
| Up to March 2017 | 30% | 80% in 0.5[s] | 80% in 1.0[s] |
| April 2017 onwards | 20% | 80% in 0.1[s] | 80% in 1.0[s] |

In case frequency variation, the FRT requirements for PV systems are shown in Fig. 36.




(a) For step change in frequency (b) For ramp change in frequency

**Fig. 36 FRT requirements for PV systems in Japan**

## Transparency and publicity practices adopted by DNOs

The aim of this section is to describe practices adopted by DNOs so as to inform potential investors on the available hosting capacity of the networks. In this way, investors are assisted to make preliminary decisions regarding project placement and sizing.

In Ontario (Canada), Ontario Power Authority (OPA) has published a transmission availability table (Table 25) which indicates the system's electricity availability to host new renewable generation power plants. The transmission availability test considers:

- the existing transmission system (i.e. the IESO-controlled grid).
- committed transmission system upgrades.
- existing and committed generation facilities.
- the balance between electricity load and generation.

In this Table 25 there are three levels of assessment provided, as shown on the following excerpt of the actually published one [89], [90][16]:

- transformer station test,
- transmission circuit test,
- area test

[16] Note 1 means "Not expected to be limiting"

**Table 25: Transmission availability table which indicates DER available capacity in each HV/MV substation (Canada - Ontario Power Authority)** [89], [90]

| Station Name | Bus Name | Available Station Capacity (MW) | Supply Circuit 1 | Availability (MW) | Supply Circuit 2 | Availability (MW) | Area | Area Limit (MW) |
|---|---|---|---|---|---|---|---|---|
| AGIMAK DS | Total | 7 | 29M1 | 0 | | | Northwest | 100 |
| AGINCOURT TS | Total | 22 | C10A | 50 | C4R | 50 | Central | Note 1 |
| AGINCOURT TS | B | 11 | C10A | 50 | C4R | 50 | Central | Note 1 |
| AGINCOURT TS | Y | 11 | C10A | 50 | C4R | 50 | Central | Note 1 |
| ALBION TS | Total | 11 | M30A | 0 | M31A | 0 | East | 1500 |
| ALBION TS | BQ | 5 | M30A | 0 | M31A | 0 | East | 1500 |
| ALBION TS | JY | 5 | M30A | 0 | M31A | 0 | East | 1500 |
| ALLANBURG TS | Total | 22 | A6C | 110 | A7C | 100 | Central | Note 1 |
| ALLISTON TS | Total | 61 | E8V | 140 | E9V | 140 | Central | Note 1 |
| ALLISTON TS | T2 | 0 | E8V | 140 | E9V | 140 | Central | Note 1 |
| ALMONTE TS | Total | 25 | M29C | 200 | | | East | 1500 |
| ALMONTE TS | J | 22 | M29C | 200 | | | East | 1500 |
| ALMONTE TS | Q | 25 | M29C | 200 | | | East | 1500 |
| ANDREWS TS | Total | 3 | Gartshore 1 | 20 | Gartshore 2 | 20 | Northeast | 300 |
| ANJIGAMI TS | Total | 15 | Not expected to be limited by a supply circuit | | | | Northeast | 300 |
| ARDOCH DS | Total | 6 | B1S | 0 | | | East | 1500 |

The above limits apply for both transmission and distribution connected power plants.

Hydro One Inc. (Canada) has published a list that shows the generation (capacity) that can be added at each bus or substation. A part of this list is shown on the next Table 26 [91].

**Table 26: DER interconnection availability table for each HV/MV substation or bus (Canada - Hydro One Inc.)** [91]

| Station Name | Bus Name | Feeder Name | Voltage (kV) | Minimum Load (MW) | Short Circuit Capacity (MVA) | Thermal Capacity (MW) | Upstream TS | Upstream TS feeder |
|---|---|---|---|---|---|---|---|---|
| BOWMANTON DS | Total | F1,F2,F3 | 8.32 | 1.1 | N/A | 3.5 | PORT HOPE TS DESN1 | M15 |
| BRACEBRIDGE TS | B | M20 | 44 | 0.1 | 1003.1 | 40.1 | | |
| BRADFORD DS | Total | F1,F2,F3 | 8.32 | 1.0 | N/A | 3.4 | HOLLAND TS | M3 |
| BRAMALEA TS DESN1 | B | M1,M3,M5,M7,M9,M11 | 27.6 | 11.2 | 39.0 | 27.2 | | |
| BRAMALEA TS DESN1 | Y | M2,M4,M6,M8,M10,M12 | 27.6 | 16.2 | 40.6 | 32.2 | | |
| BRAMALEA TS DESN1 | Total | M1,M3,M5,M7,M9,M11,M2,M4,M6,M8,M10,M12 | 27.6 | 27.4 | N/A | Sum of Buses | | |
| BRAMALEA TS DESN2 | JQ | M23,M25,M27,M29,M24,M26,M28 | 44 | 11.6 | 380.5 | 51.6 | | |
| BRAMALEA TS DESN3 | EZ | M44,M46,M48,M50,M43,M45,M47 | 44 | 53.8 | 277.3 | 113.8 | | |
| BRANT TS | BY | M11, M12, M13, M14, M21, M22, M23, M24 | 27.6 | 21.0 | 240.7 | 61.0 | | |
| BRANTFORD TS | Y | M21,M23,M25,M27,M29 | 27.6 | 21.0 | 68.9 | 37.0 | | |
| BRANTFORD TS | Z | M22,M24,M26,M28,M30 | 27.6 | 19.5 | 74.2 | 35.5 | | |
| BRANTFORD TS | Total | M21,M23,M25,M27,M29,M22,M24,M26,M28,M30 | 27.6 | 40.5 | N/A | Sum of Buses | | |
| BRIDGENORTH DS | Total | F1,F2,F3 | 8.32 | 0.8 | N/A | 3.2 | DOBBIN DS | F2 |
| BRIDGMAN TS DESN1 | A1A2 | For any information or inquiries please contact Toronto Hydro | 13.8 | 12.4 | TC | 12.4 | | |
| BRIDGMAN TS DESN2 | LA1&LA2 | For any information or inquiries please contact Toronto Hydro | 13.8 | 17.5 | TC | 17.5 | | |
| BRIDGMAN TS DESN3 | LA5&LA6 | For any information or inquiries please contact Toronto Hydro | 13.8 | 7.4 | 0.0 | 7.4 | | |
| BRIDGMAN TS DESN4 | LA7&LA8 | For any information or inquiries please contact Toronto Hydro | 13.8 | 18.8 | TC | 18.8 | | |
| BRIGDEN DS | Total | F1,F2,F3 | 8.32 | 0.6 | N/A | 2.3 | WANSTEAD TS | M4 |
| BRIGHTON DIVISION DS | Total | F1,F2,F3 | 4.16 | 0.6 | TC | 2.0 | SIDNEY TS | M7 |
| BRIGHTON DS #2 | Total | F1,F2 | 8.32 | 0.7 | TC | 1.7 | SIDNEY TS | M7 |
| BRIGHTON PINNACLE DS | Total | F1,F2,F3 | 4.16 | 0.6 | TC | 3.0 | SIDNEY TS | M7 |
| BRIGHTON SHARPE DS | Total | F1,F2,F3 | 4.16 | 0.6 | TC | 3.0 | SIDNEY TS | M7 |

There are two criteria applied, namely the thermal and short circuit capacity. More detail on these criteria is provided in the Canada section of Chapter 2.

Hydro One, apart from the above list which indicates the capacity in a substation, has uploaded to its web site an excel file which calculates the station and feeder capacity having as input values the feeder, the kind of DG (technology) and the nominal power of DG [92]. The output of this calculator is “pass” or “fail”. In this way, Hydro One provides a preliminary study for the availability of the capacity in a specific feeder of a specific substation.

There are four criteria [92]:

1. Feeder loading and feeder generation capacity limitations on the distribution system: The total current shall not exceed either 200A (for those feeders operating below 13.8 kV) or 400A (for those feeders operating at or above 13.8 kV). This criterion was developed in response to Hydro One’s experience of unacceptable feeder voltage fluctuations and power quality issues when a large amount of generation has been connected at a distance from the supply station, as well as to respect equipment limitations.
2. Available thermal capacity at the distribution or transformer station and upstream transmission station: Generation at the distribution station shall not exceed 60% of the maximum MVA rating of the Hydro One single transformer and minimum station load. These limits are necessary to protect equipment that is currently installed in the station.

3. Loading vs. generating balance on the distribution feeder: total generation must not exceed 7% of the annual line section peak load on F-class feeders or 10% for M Class feeders. Specifically, connection would not comply with anti-islanding distribution system requirements.
4. Available short circuit capacity at the distribution station and upstream transmission station.

For instance, a PV power plant with a nominal power of 1 MW can be connected ("Pass") to Feeder 3 of the ABERDEEN substation, as shown on the following figure.

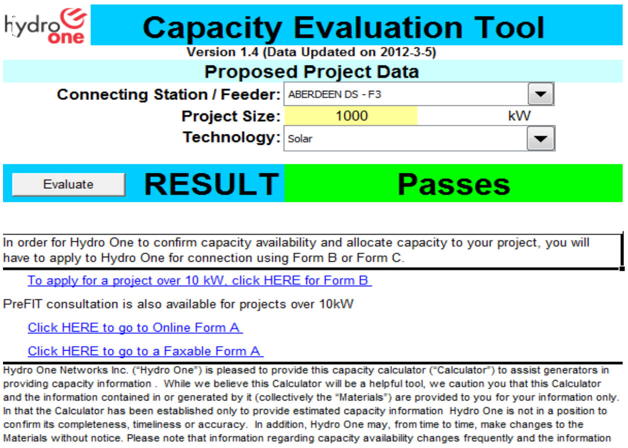



**Fig. 37 Capacity Evaluation Tool - Excel file (Canada-Hydro One Inc.)** [92]

On the other hand, a wind power plant with a nominal power of 3 MW cannot be connected ("Fail") to the Feeder 2 of the ADDISON substation because of the first criterion, as shown on the following figure.

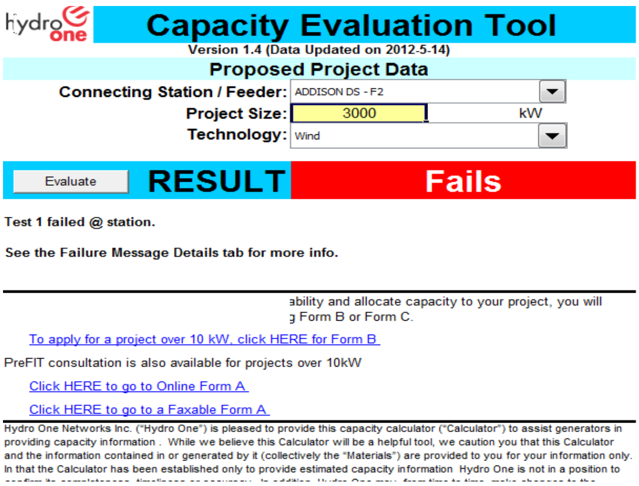



**Fig. 38 Capacity Evaluation Tool - Excel file (Canada-Hydro One Inc.)** [92]

Both aforementioned methods (excel tool and calculation using the equivalent lists), used for the assessment of the available capacity, do not substitute the Connection Impact Assessment [36].

Nova Scotia (Canada), taking into account similar to the above criteria and the already connected DER, provides a map showing the available generation capacity intending to guide the investors concerning the preliminary selection of a DER site. For instance, the following Fig. 39 shows one such map with information related to available capacity [93].

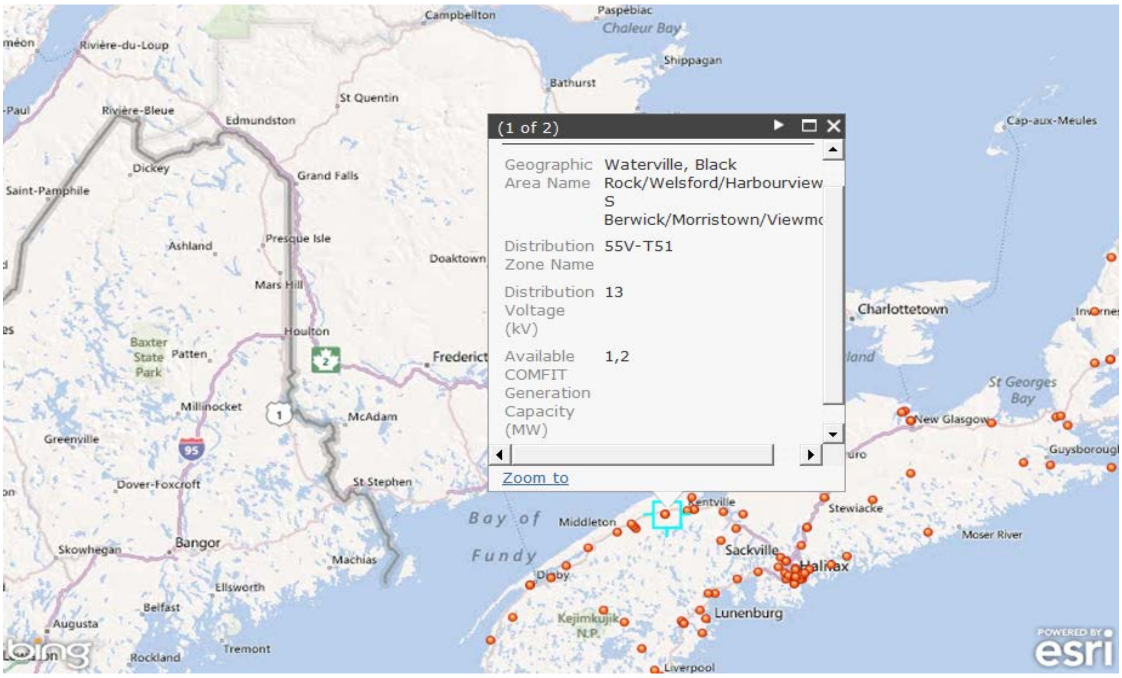



**Fig. 39 Map showing available DER capacity (Canada - Nova Scotia)** [93]

Hydro Ottawa publishes information on a bi-weekly basis related to the remaining available capacity for inverter based generation per feeder per substation, informing in this way the investors how feasible an interconnection is to the site they are interested in. Factors that affect capacity availability are for instance [94]:

- Capacity granted by the transmitter per station bus or bus-pair.
- Overall capacity constraint on the transmission system.
- Generator proponents downsizing their generation systems.
- Offers-to-connect made to a generator proponent.
- Expiry of offer-to-connects freeing the allocated capacity.

In other words, the DNO has already calculated, based on the impacts of DER on short circuit levels, voltage deviations and operational issues, the following capacities [22], [95] which can be provided to the investor:

- Circuit Maximum Allowable Unit Capacity (kVA).
- Circuit Maximum Allowable Aggregate Capacity (kVA).
- Substation Maximum Allowable Aggregate Capacity (kVA).

In determining the actual available capacity, the least available capacity along the feeder to transmission system path dominates. Thus, though capacity may be available at the distribution feeder level, there is a constraint at the transmission level (115kV and 230kV), and there may be a constraint in between at the station bus-level (indicated as "High Voltage Distribution System Bus"). Capacity for non-inverter based generation is less than the published figures. The following Table 27 shows a part of the published information provided by Hydro Ottawa [94].

**Table 27: DER interconnection availability table for each HV/MV substation or bus (Canada - Hydro Ottawa)** [94]

| First Feeder | First Station | First Feeder Voltage (kV) | High Voltage Feeder | High Voltage Feeder Voltage (kV) | High Voltage Distribution Station & Buss or Buss-Pair | Remaining Available Capacity (kW) | Constraining Factor | Constraining Element |
|---|---|---|---|---|---|---|---|---|
| 628 | SLATER TS | 13.2 | | | SLATER TS-B1B2 | - | Short Circuit Limit | Restricted Station |
| 629 | SLATER TS | 13.2 | | | SLATER TS-B1B2 | - | Short Circuit Limit | Restricted Station |
| 630 | SLATER TS | 13.2 | | | SLATER TS-B1B2 | - | Short Circuit Limit | Restricted Station |
| 631 | SLATER TS | 13.2 | | | SLATER TS-J1J2 | - | Short Circuit Limit | Restricted Station |
| 632 | SLATER TS | 13.2 | | | SLATER TS-Q1Q2 | - | Short Circuit Limit | Restricted Station |
| 633 | SLATER TS | 13.2 | | | SLATER TS-B1B2 | - | Short Circuit Limit | Restricted Station |
| 1801 | OVERBROOK TO | 13.2 | | | OVERBROOK TS-J1J2 | 1,000 | Thermal Limit | Distribution Feeder |
| 1802 | OVERBROOK TO | 13.2 | | | OVERBROOK TS-Q1Q2 | 1,000 | Thermal Limit | Distribution Feeder |
| 1804 | OVERBROOK TO | 13.2 | | | OVERBROOK TS-J1J2 | 1,000 | Thermal Limit | Distribution Feeder |
| 1806 | OVERBROOK TO | 13.2 | | | OVERBROOK TS-Q1Q2 | 1,000 | Thermal Limit | Distribution Feeder |
| 1807 | OVERBROOK TO | 13.2 | | | OVERBROOK TS-J1J2 | 1,000 | Thermal Limit | Distribution Feeder |
| 1808 | OVERBROOK TO | 13.2 | | | OVERBROOK TS-Q1Q2 | 1,000 | Thermal Limit | Distribution Feeder |
| 1809 | OVERBROOK TO | 13.2 | | | OVERBROOK TS-J1J2 | 1,000 | Thermal Limit | Distribution Feeder |
| 2201 | ALBION TA | 13.2 | | | ALBION TS-JY | 365 | Buss Threshold Limit | High Voltage Distribution System Buss |
| 2202 | ALBION TA | 13.2 | | | ALBION TS-BQ | 1,000 | Thermal Limit | Distribution Feeder |
| 2203 | ALBION TA | 13.2 | | | ALBION TS-BQ | 1,000 | Thermal Limit | Distribution Feeder |
| 2204 | ALBION TA | 13.2 | | | ALBION TS-JY | 365 | Buss Threshold Limit | High Voltage Distribution System Buss |
| 2205 | ALBION TA | 13.2 | | | ALBION TS-JY | 365 | Buss Threshold Limit | High Voltage Distribution System Buss |
| 2206 | ALBION TA | 13.2 | | | ALBION TS-JY | 365 | Buss Threshold Limit | High Voltage Distribution System Buss |

Electricity Northwest (UK) applies the short circuit and thermal criteria to determine the capacity of the substations. The following part of a map shows the distribution areas of 132/33kV substations [96].

Green: The fault level is less than 95% of the fault rating of the substation and likely to be able to connect a 25MW generator.

Amber: The fault rating is between 95% and 100% of the fault rating of the substation and connection of 25MW will need consideration.

Red: The fault level is in excess of 100% of the fault rating of the substation and unlikely to be able to connect a 25MW generator without reinforcement.

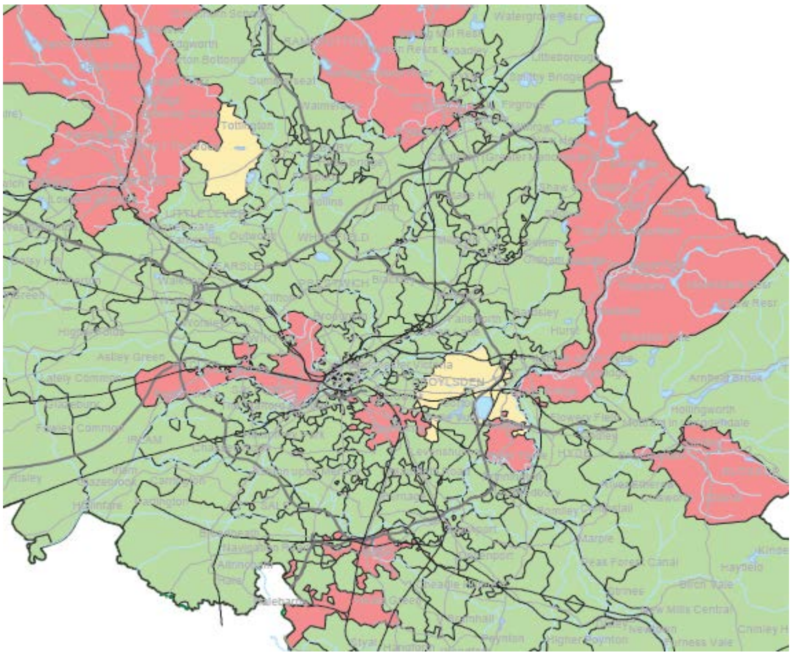


**Fig. 40 Map showing the available substation short-circuit DER capacity (UK – Electric Northwest)** [96]

The Thermal Capacity map shows the use-of–system prices when connecting generation at the busbars of a 132/33kV substation. The use-of-system prices are directly related to the available capacity; specifically, where a price is low there is spare capacity whilst high prices indicate limited or no spare capacity. The following part of a map shows the distribution areas of 132/33kV substations [97].

Green: Annual use-of-system price less than 1£/kVA/annum – available spare capacity to connect DG.

Amber: Annual use-of-system price above 1£/kVA/annum but below 2£/kVA/annum – limited spare capacity constraining the ability to connect DG.

Red: Annual use-of-system price above 2£/kVA/annum – unlikely to have sufficient capacity to connect DG without reinforcement.

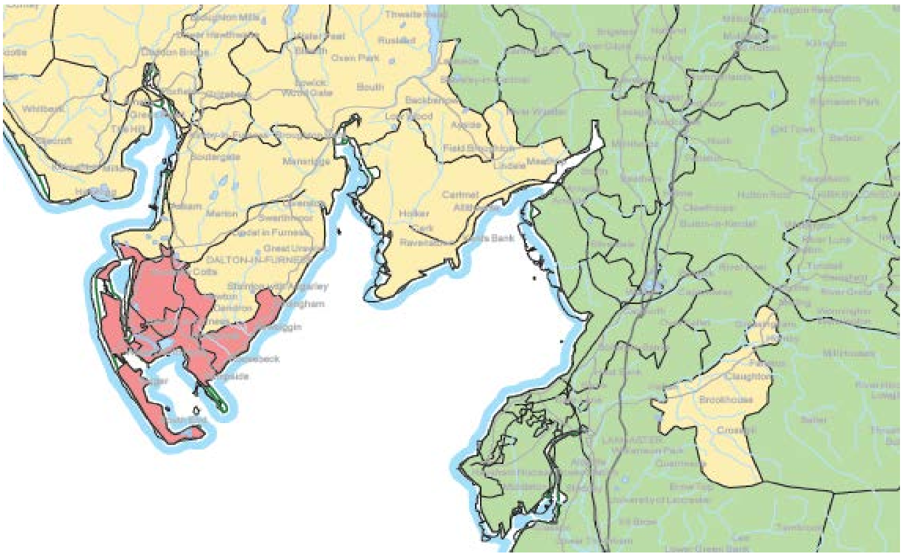


**Fig. 41 Map showing the available substation thermal DER capacity (UK – Electric Northwest)** [97]

There are also similar to the above maps for both 33/11 kV and 33/6.6 kV substations.

ConEdison (USA-New York) has carried out a study for determining the Fault Current Margin in all areas of New York. For instance, the following Fig. 42 shows the Fault Current Margin[17] in Manhattan.

[17] The amount in amperes by which the rated fault interrupting capability of the circuit breakers at an area substation exceeds the available fault current identifiable in a Load Area. The Company posts on its DG web site a map that identifies operating areas without fault current limitations and a schedule of planned upgrades of breakers in operating areas with fault current limitations. FCM is re-calculated at regular intervals in order to reflect the contribution to fault associated with DG projects in the queue that have been assigned FCM allocations as well as system modifications that can change at any time due to a variety of factors, e.g., a change in transformer impedance.

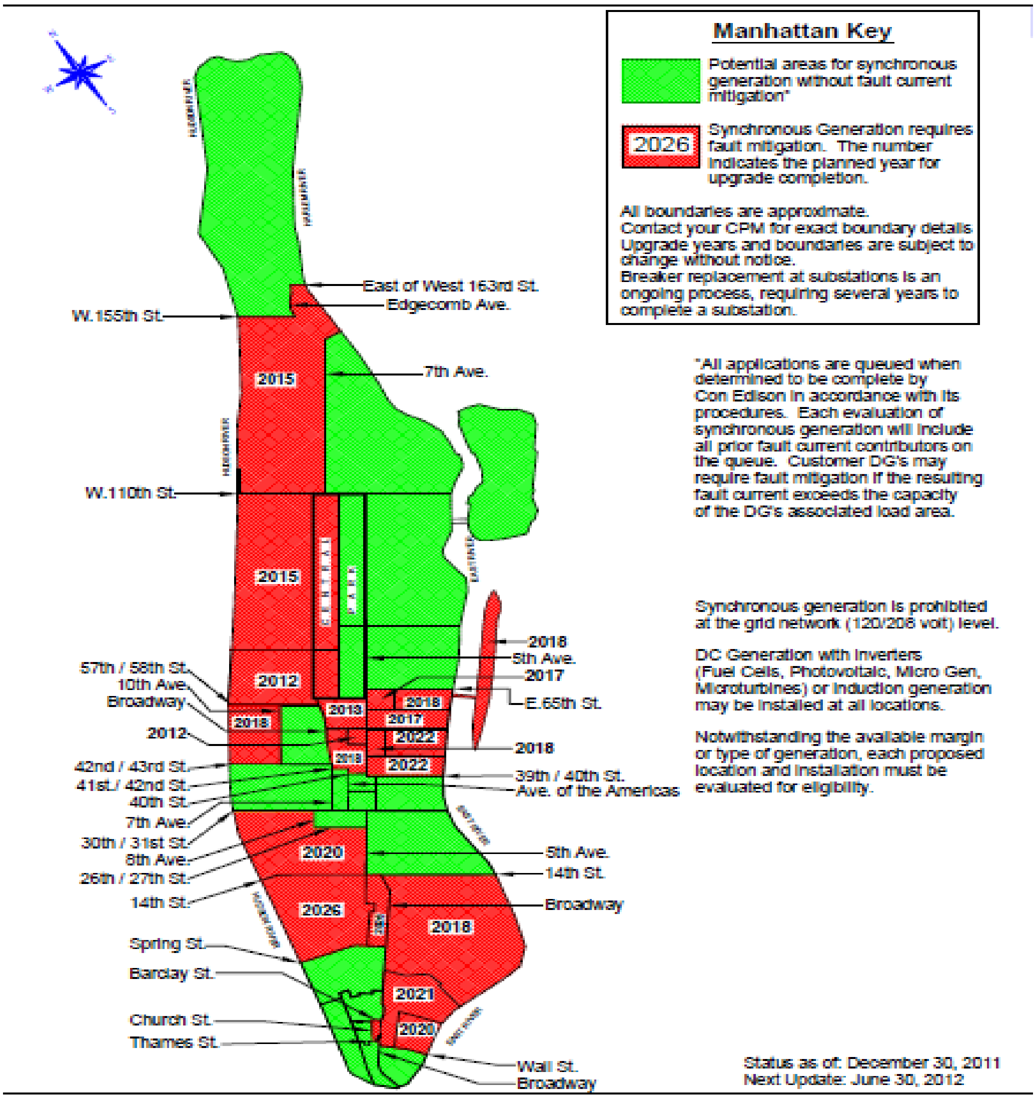



**Fig. 42 Map showing the available short-circuit DER capacity (USA – New York)**

# CHAPTER 3 - MEANS AVAILABLE TO INCREASE HOSTING CAPACITY

## Australia

Connecting DER to the DNSP's[18] network may require construction or rearrangement of up to three separate portions of the electrical network, namely:

- between the generator and the point of connection.
- between the point of connection and the DNSP network (known as the shallow connection works).
- upgrading works within the DNSP network (known as deep connection works).

Shallow connection works are those works that are exclusively for the use of the DER. They normally consist of construction of new assets or rebuilding and/or rearrangement of existing network assets. Deep connection works, on the other hand, are carried out to network assets that are shared by other customers or with the DNSP itself. These works may involve augmentation of existing circuits or upgrading of equipment to meet the higher design fault levels caused by the connection of the new generating plant (see Fig. 43).

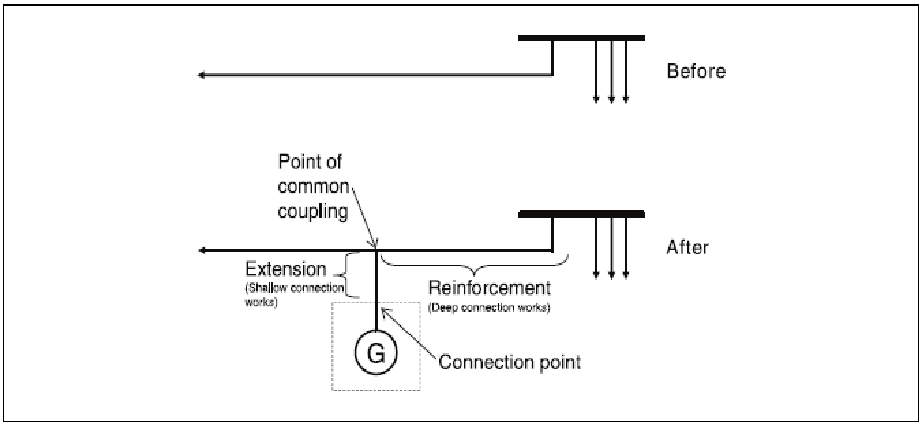



**Fig. 43 Possible interconnection works** [1]

It is not uncommon for two or more DER to be in the same area. In such cases, the limited availability of spare network capacity can lead to disputes between the developers and the DNSP over the allocation of network reinforcement costs. Currently, there are no clear rules covering these situations. Depending on the approaches taken by the developers and the DNSP, the reinforcement costs can either be allocated on a 'first come, first served' basis, or they can be shared in a more equitable way based on a proportion of the benefit derived by the affected parties. NECA has canvassed this method for levying transmission connected generators for the cost of new transmission works, although the method has not currently been implemented [1].

As far as the violation of short circuit limit is concerned, the problem may be resolved in a number of ways. It may be possible to use a different type of electrical source with an inherently lower fault contribution. If the connection scheme includes step-up transformers, it may be possible to specify high impedance transformers. Alternatively, a fault current limiting reactor can be included in the connection scheme. In some instances the replacement of existing plant and other equipment may be required [1].

The impact of DER on voltage regulation can be very serious and measures for addressing several problems that arise have to be taken. Firstly, due to very high DER penetration the OLTC can reach its lowest position and is then unable to provide any further voltage control. Technically, these cases may require larger tap ranges on the transformer to facilitate the level of DER. However, the financial implications of transformer replacement are expected to present a significant barrier to this level of EG penetration. Secondly, if the control scheme of the

[18] Distribution Network Service Provider

OLTC is based on Line Drop Compensation, a readjustment of the control settings is required. Thirdly, there is still strong possibility that an overvoltage can be caused close to consumers, although the automatic voltage regulators have been readjusted and feasible reinforcements have been made. One method of overcoming this is to review the settings and adjust the taps of the distribution transformer appropriately. A more costly and less desirable method is to replace the affected transformers with automated tap changing transformers. While technically feasible it can be assumed that a large number of transformers will need to be replaced resulting in high associated costs [12].

## Austria

The DNO can alleviate problems related to voltage caused by the DER's connection by implementing voltage or reactive power control schemes such as constant power factor or even controlling reactive power depending on the voltage levels. Regarding the increasing importance of reactive power in the networks, a common required power factor of 0.9 leading is under consideration at the moment, independent of the used generation technology. In specific cases, different power factors are required for summer and winter, depending on the load and voltage of the network. Moreover, if the DER is to be connected to a point with low short circuit, the generator may be required by the DNO to consume reactive power so as to limit voltage increase. In this case the generator has to pay for the consumed reactive power. In such cases, the voltage rise can be negative if the voltage drop caused by the reactive power flow is bigger than the equivalent of the generated active one. Another policy that can be implemented is power curtailment [16].

## Canada

In the presence of generation, feeder capacitor banks can increase the possibility of overvoltage or overcompensation and the possibility of islanding. If the DER's proposed location is presently within the zone of influence of a feeder capacitor bank, the bank shall be fitted with automated switching [19]. The generator voltage volt-amperes reactive (VAr) schedule, voltage regulator, and transformer ratio settings will be jointly determined by the DNO (NB Power) and the owner of the DER to ensure proper coordination of voltage regulation [19].

According to [22], in Ontario, renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities are limited to the following [22]:

- Modifications to, or the addition of, electrical protection equipment.
- Modifications to, or the addition of, voltage regulating transformer controls or station controls.
- The provision of protection against islanding (transfer trip or equivalent).
- Bidirectional reclosers.
- Tap-changer controls or relays.
- Replacing breaker protection relays.
- Supervisory Control and Data Acquisition system design, construction and connection.
- Any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows.
- Communication systems to facilitate the connection of renewable energy generation facilities.

## Czech

All new DER that will be connected to the distribution system, must be designed so as to facilitate installation of remote control equipment needed for the management (curtailment) of their generation. DER with rated power lower than 100 kVA must be equipped with a switching element allowing a remote disconnection of the power source from a parallel operation with a DS[19] (e.g. through MRC). This element must be designed in such a way that it will stay functional after the disconnection of the respective generator from the parallel operation with the DS and so it will enable the automation of this process.

DER with rated power output in excess of 100 kW must – in order to provide for a secure operation – include the remote control system that the DSO requires; in particular the following functionalities must be met:

- Control of the switch with the disconnecting function (primarily for the purpose of disconnection in critical conditions in the network – remote switching off/on).
- Active power curtailment.
- Reactive power control.
- Data transmission interface.

For increasing hosting capacity, the following practices are used:

- **Active power adjusting depending on operation conditions**

  In specific cases (given below), the DER must be able to operate with reduced active power output, or it must – for a temporary period – be able to reduce its maximum output as long as the conditions of the network do not improve enough to allow for injecting the complete rated power of the generator. The DSO does not intervene in the generator control and only sets the requested value.

  DSO is entitled to change active power output of a generator under the following network conditions:

  - A potential threat to a secure operation of the system (e.g. emergency conditions and their prevention).
  - Essential operational activities or a threat of overload in the distribution system.
  - A threat of islanding.
  - Threats to static or dynamic stability.
  - Increase of frequency threatening the power system.
  - Maintenance works or building activities.

  The reduction of the power delivered to the point of connection to the value requested by DSO (e.g. to 60%, 30% and 0% of installed capacity for PVPPs; 100 %, 75 % and 50 % for biogas stations) must be carried out without any delay, 1 minute at the most. At the same time, full reduction to the value of 0% must be technically feasible without an automatic disconnection of the generator from the network.

- **Proposal for rules allowing the release of feed-in capacities for the connection of DER**

  According to several studies, the dominant majority of the total annual production of energy deriving from DER is generated using only a half of the reserved annual distribution capacity which DSOs had to reserve! Moreover, DSO has to take into account the nominal power of the DER, which will be injected to the network, however, just for a few hours in the year. This unambiguously shows that the current rules have to be amended in such a manner that they can increase the number of connected distributed sources to the distribution grid. Economically and rationally, it is inadmissible to design distribution grids for leading out their full rated output power, which is used just in a fraction of their annual generation schedule.

  Under practical conditions, this means that the DSO (or TSO) should be allowed operatively (according to the need to regulate the system imbalance) to curtail electricity generation from these DER, primarily at higher voltage levels (i.e., 110 kV and TS levels). During periods of high generation from these sources, it will thus be possible to lead excessive output power out of sites through 110 kV lines of distribution grids and through the transmission network to sites with higher consumption. Here, the term “operative curtailment of maximum output power“ is used to denote a reduction of electricity production of particular

[19] Distribution System

DER with variable output power by a remote control command issued by the TSO or the DSO so as to avoid non-standard operating conditions in the Czech power system or even threats to its secure operation.

Assuming that this rule will be introduced in practice, distribution networks at lower voltage levels (LV and HV) will have to keep on satisfying the conditions for the secure transfer of rated power of all DER. This, however, does not have to apply for the 110 kV level and for the transmission system, due to the inclusion of the sources into the system of controlled operative curtailments.

- **Selective operative curtailment of generation**

  Operative curtailment of the maximum output power should be carried out in a selective manner, depending on the responsibility of DER for their own production (depending on the nature of the RES support). There are two different mechanisms of the support of electricity from RES in Czech Republic – purchase prices (the DER do not bear any responsibility for an imbalance) and the so-called green bonuses, which are fixed bonuses adding up to the price of RES electricity reached by its producer at the wholesale market (the responsibility for an imbalance is born by either the producer himself or by the trader purchasing RES electricity).

  If an operative curtailment is needed, the sequence of curtailments would be as follows:

  1) Curtailment of those DER which do not bear the responsibility for an imbalance brought about by their generation. These DER work quite independently, irrespective of the demand of the consumer sector. They generate electricity “when natural conditions allow so” (i.e., if wind is strong enough or if there is enough sunshine). They do not bear any responsibility for their generation or for a lack of it, which ultimately impacts the TSO (ČEPS, plc) and is reflected in the price of system services (and hence the price for final customers).

  2) Only in the case of a high system imbalance (due to RES), when the curtailment of the generation through “operative control“ does not come about, standard regulation elements will be activated.

## Denmark

Most of the DER like solar PV, EVs, battery storages etc. are typically interfaced with inverters. Using simple modifications to the firmware and no extra hardware cost, these units may provide important grid functions like:

a. Frequency support by active power control.
b. Voltage support by reactive power injection.
c. Black start capability.
d. Fault-ride through as described in VDE-AR-N 4105.

The communication interface between the DER and DNOs for active control and coordination of these units in ensuring grid stability requires a clear framework and standardisation. As the penetration levels and impacts of small DER units become significant in the Danish distribution grids, it is expected that the grid supporting functions discussed in the grid codes will be put to an immediate effect. The norms and regulation for ancillary services in terms of grid regulation (up-regulation and down-regulation) are currently managed by the TSO at the transmission level. As the distribution grids in the future may have a large amounts of small flexible generation (solar PV, V2G etc.) and consumption units (EVs, heat pumps etc.), the framework have to be reformulated with active roles expected from more local players like the DSO’s, retailers, aggregators etc. in providing these services.

Among the various DER, the wind power plants are the matured and well-established technology in the Danish electricity grids. The majority of these turbines are connected to MV grids separated from the consumer networks, where the quality of the power supply is maintained well in accordance with the existing grid codes. In view of the future energy policies, the DER like solar PV, EVs etc. are expected to penetrate much of the secondary distribution grids. With the significant amount of such units in the local grids, the distribution operators have to address some critical issues like voltage regulation, overloading of grid components, power quality and protection.

To establish cost-effective distribution system operation, the first two factors are the most critical and primary tasks to be investigated and solved. The selection of one or combination of solutions like automatic transformer tap-changers, inverter based real and reactive power control, storages, capacitor/reactor banks, capacity enhancement of distribution transformers, and modification of grid and feeder configurations etc. are dependent on the trade-off between cost, reliability and complexity.

According to TF 3.2.5 [45] which refers exclusively to wind turbines power plants with a nominal power greater than 11 kW, the latter must be equipped with reactive power and voltage control functions for controlling both reactive power and voltage at the point of connection (POC), via orders using setpoints and gradients, aiming at improving voltage regulation. Reactive power control could be achieved either by setting a desired value for the reactive power independently of the active power or by setting a function based on the active power through power factor alteration. Both these mentioned policies are illustrated in the following figure.

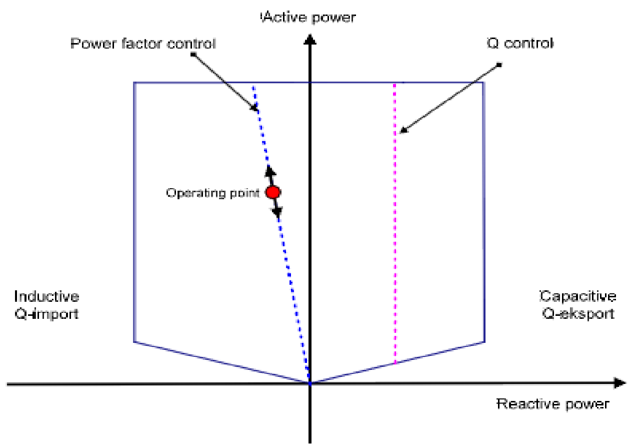



**Fig. 44 Power factor and reactive power control of DER** [45]

As for the voltage control at the point of connection of the wind power plant, this can be achieved by varying the generated or consumed reactive power through a droop[20] function. For instance, such droop functions could be the curves that are illustrated in the following figure.

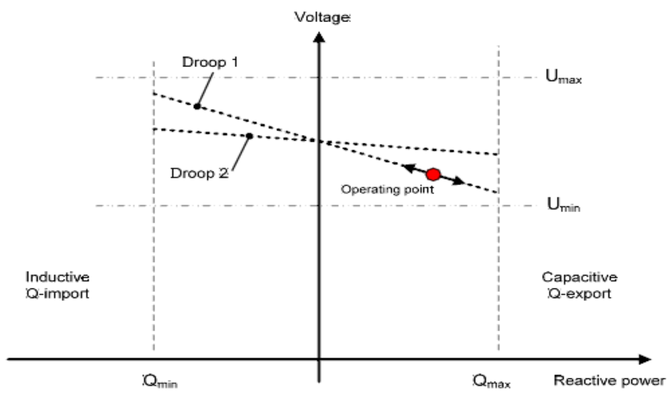



**Fig. 45 Q-V DER control (droop function)** [45]

A case study is presented in Annex E.

[20] Droop is the voltage change (p.u.) caused by a changed in reactive power (p.u.) (linear characteristic V-Q)

## France

Means proposed to increase DER hosting capacity of distribution feeders are presented.

**Management of voltage constraints on distribution feeders**

Voltage limitations on distribution networks provide often a limitation to the DER hosting capacity of distribution networks. This is due to the law of voltage variation along a conductor:

$\Delta U = ( RP + XQ ) / U$ (12)

This limitation of voltage rise typically occurs in summer on feeders with high lengths and DER connected along or at the end of a feeder (for instance solar panels connected to a rural network), as the voltage increase caused by high DER power generation is not compensated by the voltage decrease that results from low power consumption on that feeder. In that case the high admissible voltage limit of the distribution network might be overridden. A way to mitigate this voltage constraint is to apply active management to the voltage of the distribution network.

- Coordinated voltage control at substations

  On Line Tap Changers at HV/MV and/or MV/MV substations can be used for a coordinated voltage control on the distribution network.

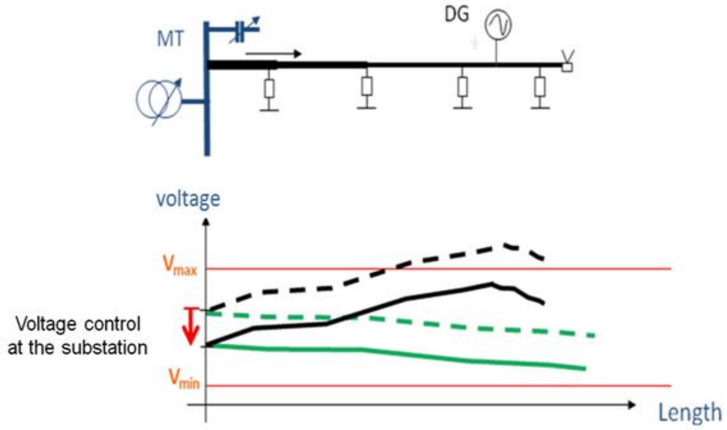



**Fig. 46 On Load Tap Changer in coordinated voltage control**

The principle of the regulation is to adapt the level of the voltage at the substation in order to adapt to variations of the voltage along the feeder that are due to either consumption or power generation of DER and maintain this voltage within admissible limits.

While dealing with the local voltage issues, this method also allows the optimization of losses on the feeder by minimizing the transit of reactive power. This method can be combined with local reactive compensation by DER to increase hosting capacity.

However, such a method requires sufficient real time knowledge of the voltage along the feeder. This knowledge requires the appropriate sensors along the feeder together with the capability to compute the voltage along this feeder. Coordinated voltage control involves a more complex set of measures and controls throughout the distribution network but should, in principle, remain an economical solution. Detailed studies and experimentations are necessary to assess the precise economics of this option.

- Decentralized storage used for peak shaving

  Storage is in theory another way to reduce the injection of active power on the distribution network as it can absorb and produce active and reactive power and provide peak shaving services. Considering its cost, storage should not be limited to peak shaving and should provide other services. This point is currently under study.

Current situation in France

Coordinated voltage management at HV/MV substations will be tested in 2012 and 2013 for a possible implementation in the future. Decentralized storage is under study.

The management of the voltage constraints can be fulfilled using the following methods:

- Local reactive compensation by DER

  The absorption of reactive power by a DER provides a reduction of voltage at its connection point and along the feeder and therefore allows maintaining the voltage on that feeder within admissible limits.

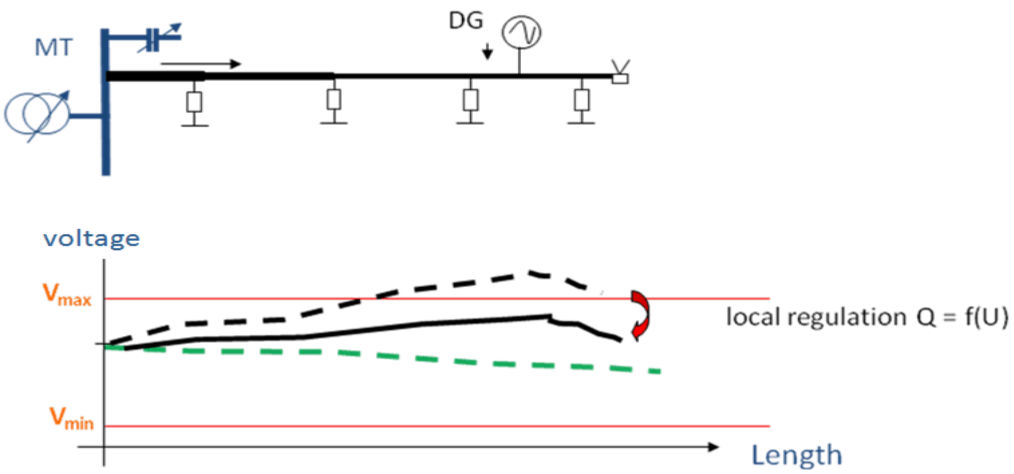



**Fig. 47 DER (local) reactive compensation for voltage regulation**

On the contrary, the supply of reactive power will support the voltage of the network in case of low voltage. The action on the sole reactive power allows not to disturb the production of active power while acting on the voltage. This reactive power compensation has to be applied locally (at the connection point of the DER) to provide for the best compensation to the voltage increase that result from the DER active power generation. Therefore the optimum is to have this reactive power absorbed or supplied by the DER itself.

The absorption or supply of reactive power can be implemented in LV and in MV.

It can be implemented through:

- A fixed power factor (tanφ) at the connection point of the DER. However this type of control does not provide for enough flexibility throughout the year as the respect of admissible voltage limits on the feeder may for instance not only need that the DER absorb reactive power in summer but also need the same DER not to absorb reactive power in winter in order not to worsen voltage decrease due to absorption of reactive power by the consumers and thus avoid the underriding of the low admissible voltage limit.

- A control method that links the reactive power produced or absorbed by the DER to the voltage measured at its connection point.
  For instance, if avoiding overriding the high admissible voltage limit is the only concern, a control law that provides that the DER absorbs reactive power in case of high voltage and remains passive when the voltage is low is appropriate. The following figure provides a schematic example of a possible control law:

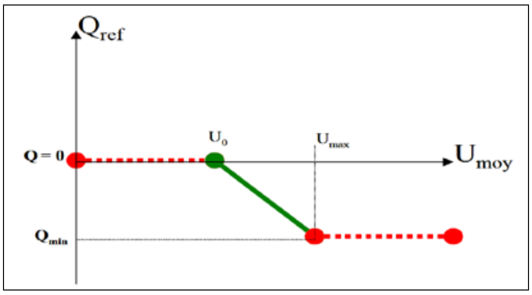



**Fig. 48 Reactive power control in case of overvoltage situation**

If compensation for low voltage is required, other control laws are possible:

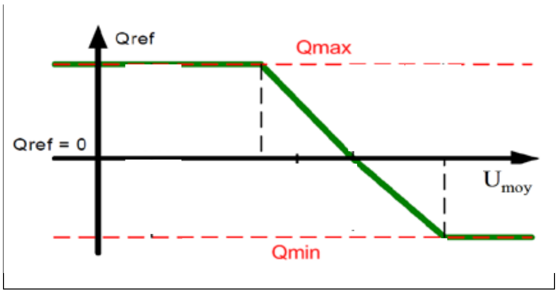



**Fig. 49 Reactive power control (general concept)**

Another possibility is to introduce a dead band in the control law:

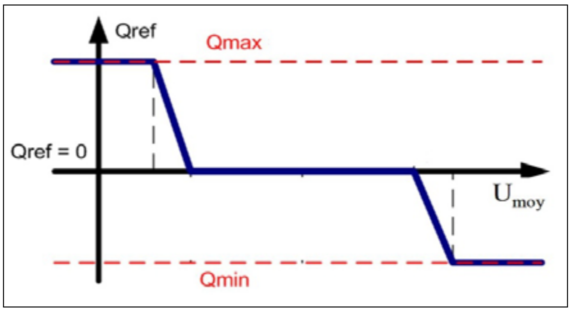



**Fig. 50 Reactive power control using a voltage dead band**

The dead band allows less solicitation of the equipments for the DER and the voltage regulation equipment at the HV/MV or MV/MV substation.

The reactive power absorbed locally will have to be produced upstream on the distribution network, for instance at the substation level. Thus the resolution of the voltage problem locally induces a flow of reactive power which might increase losses along the feeder.

- Generation curtailment

  This method, which consists in reducing temporarily the active power produced by the DER, can be used by the DNO in complement to the local reactive power compensation and the coordinated voltage control if they are not sufficient, or alone. It will act on the active power i.e. on the “P” term in the equation $\Delta U = ( RP + XQ ) / U$ to reduce the voltage rise.

  Generation curtailment allows to address peak situations, that occur throughout the year, without having to reinforce the distribution network. Such a curtailment has to be limited in time in order to limit economic losses for the DER.

The implementation of generation curtailment might in some cases provide an economical solution. The economics of such a solution can be assessed only on a case by case basis, as the cost of network reinforcement has to be balanced against the cost of lost production. Such an option has to be agreed between the owner of the DER and the DNO. Decentralized storage seems currently an expensive option for local peak shaving use.

Current situation in France

The current rules in France are:

DER connected to LV (400 V) network should not absorb reactive power.

Currently for DER connected to MV (usually 20 kV) a fixed tanφ is set contractually by the DNO within the area limited by the red lines in the following figure:

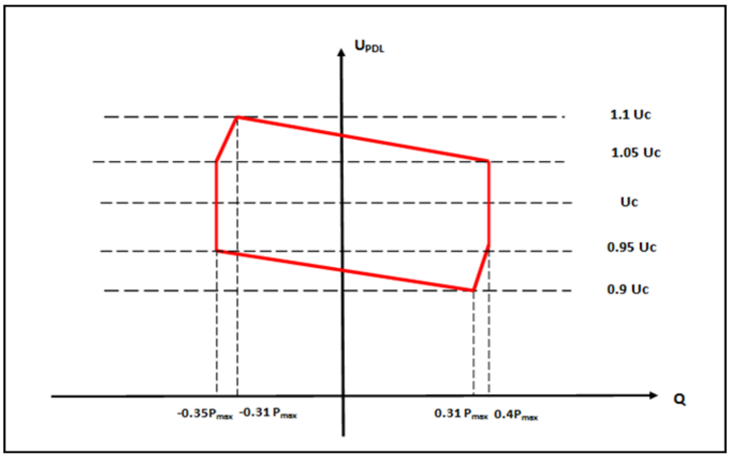



**Fig. 51 Power factor control**

The implementation of local reactive compensation (control law Q = f(U)) is going to be tested by the DNO for DER connected to MV network.

Other methods (local reactive compensation for DG connected in LV, generation curtailment, decentralized storage) are currently neither used nor in the pipe for implementation by the DNO. They are however under study.

## Germany

According to the Dena [98] (distribution system study 2012), the following means to increase hosting capacity have been identified and suggested to follow-up:

- Predictive grid planning.
- Implement innovative assets.
- Adapt technical guidelines.
- Cut generation peaks.
- Grid driven or market driven storage operation.
- Grid driven or market driven demand side management, including load reduction.

The VDE-ETG study “Active energy grids in the context of the German energy turnaround” [99], provides a good overview on suggestions to increase hosting capacity and provides recommendations to stakeholders mainly within Germany for an economic energy supply of the future.

This summary is based on the CIRED publication [100] and presents the results of the project “Power systems of the future/Smart Country”, which was supported by the German Federal Ministry of Economics and Technology from July 2009 to June 2011. With consideration of trendsetting equipment an outline of distribution grids, which are sufficient for the energy supply-tasks in 2030, is given. The aims of the project were to identify, evaluate and demonstrate economic solutions for sustainable distribution grids. Especially the real-life demonstration of innovative concepts for efficient electrical distribution grids is an important part of the project.

*Trendsetting Equipment*

Future distribution grids will still mainly use current technologies to provide an efficient power supply. Nevertheless, new equipment has to be identified based on current trends and innovative technical approaches respectively to ensure the realisation and efficiency of the future grid concepts. Especially in rural grids, new or adapted equipment can be more efficient compared to conventional grid extension, because voltage constraints are more relevant than the rated loading of the equipment. Therefore, various voltage regulators for distribution grids based on different technologies were analysed and developed.

- Direct Voltage Regulator
  The aim of a voltage regulation unit is to usually adjust the voltage on the secondary side to a pre-set value. Therefore, the voltage regulation unit decouples the operating voltage on the secondary side from the primary side.
- Wide-area Controller
  In contrast to set the voltage on the secondary side of the voltage regulator to a fixed value, a wide-area controller monitors several critical nodes in the supplied grid via remote control. The objective of the wide-area controller is not to regulate the operating voltage of a single node to a constant value, but to lead the operating voltage of all critical nodes within a determined bandwidth.
- Electronic Sectionalizer
  The electronic sectionalizer can be interpreted by its functionality as a “low-end” circuit breaker to divide supply layers inside mainline supply concept. Together with longer branch circuits it helps to keep reliability constant on a reference level. The sectionalizer differs between permanent and temporary faults and opens at a permanent fault during automatic re-closing of the upstream circuit breaker at the transformer substation.

*Innovative Grid Concepts*

An innovative grid concept can be the combination of new and conventional equipment but also a new arrangement strategy of conventional ones. Thus, a grid concept describes a solution of the energy supply-task. The economic benchmark for each innovative approach is the conventional grid extension. All identified and analysed concepts can be sorted into four groups, which are realised in the demonstration grid.

- Information and Communication Technology (ICT).
- Disposition of storage devices.
- Local voltage control to exploit grid capacity.
- Hierarchical supply layers in medium voltage level.

*Test Grid Installation and experience*

The demonstration grid is a rural area in the western part of Germany. This area has a low load and is highly pervaded by DER feed-in in the low and medium voltage level (LV, MV). All four above mentioned groups of innovative concepts are covered within the demonstration site.

- ICT – remote monitoring
  The advantages of ICT are demonstrated by observing voltage and power values at main DER and central points in the grid. A result is that about 30 measuring points are enough for advanced grid operation in this segment. Additionally, the simultaneity of the renewable generation in LV-level is determined by using ICT transmitted measurements at the connection points of the DER, the MV/LV and HV/MV substations.

- Disposition of Storage Devices
  A biogas generation plant is amended by low-pressure gas storage and it is operated to avoid electricity feed-in during powerful feed-in from solar power. This reduces grid costs and enhances grid capacity for additional generation.
- Local Voltage Control
  The local voltage control is extensively tested by installation of seven active voltage controllers (AVC). They are integrated at different positions in the distribution system from inside MV - to LV - level at single house connection points.
- Hierarchical Supply Layers
  To demonstrate hierarchical supply layers within the demonstration grid a strong cable backbone with a length of 8.5 km has been built and the already existing overhead-lines are connected to the cable via three different switching concepts. The functionality of the previously mentioned electronic sectionalizer will be compared with a remote operated load break switch and a simplified circuit breaker.

*Conclusion*

Many innovative approaches for distribution grid design are evaluated and focussed to grid concepts using trendsetting equipment in this project. The auspicious ones like voltage regulation close to the customer, virtual electricity storage, backbone grid parts and ICT are presented in this contribution. They all broaden the use of existing grid capacity under efficiency aspects and are demonstrated in a real-life grid.

In Annex F, two case studies, related to the above mentioned points, are presented.

## Greece

The most common practice to increase the hosting capacity of existing feeders is their reinforcement (re-conductoring) to increase their thermal rating and relax the voltage regulation constraints. A case study is presented in Annex G.2 showing and explaining the whole technical methodology that is applied.

Another standard practice to facilitate the interconnection of increased DER capacities is the modification of voltage regulation policies and settings in OLTC and VR. Cancellation CTs are used as a practical and effective solution in HV/MV substations where significant DER capacity is interconnected via dedicated feeders. In this way, the voltage regulator relay of the OLTC acts based on the actual load of the consumer feeders, rather than the reduced one experienced by the transformer because of the DER power injection. Step VRs are often installed on feeders serving significant DG capacity.

To address the increased fault level due to DER contribution, the installation of series reactors may be stipulated by the DNO, in order to decrease the short circuit current contribution of DER. In certain cases, where new HV/MV transformers are installed to accommodate DER aggregations, an increased short circuit voltage $u_k$ is specified for the transformer (typically 22% or higher) to decrease the network fault current contribution and thus leave more margin for DER. Both measures increase the hosting capacity to certain extent, but their cost is substantial and present additional drawback of impacting voltage regulation.

Reactive power control of DER units is currently being considered as another option to mitigate voltage regulation issues. So far, power factor regulation to a suitable but fixed inductive value (down to 0.95) is only applied. Active power curtailment is also enforced to face network congestion issues (mainly at the HV level), as well as in isolated island networks on a regular basis.

## Italy

The Italian TSO, Enel Distribuzione, has recently introduced in its network planning methods a new component, the "DG Collector" (Fig. 52 [101]), with the purpose to connect a high number of medium and small size DER, whose overall power is not compatible with current MV network, which may be already saturated or anyway saturated even only by some of the connection requests. The DG Collector is a HV/MV primary substation, designed and built to work in energy uprising condition, with energy flowing almost steadily from MV to HV network. The MV part of the Collector has to be designed for an adequate number of MV lines to allow all the connections requested. The location must be as near as possible to the barycentre of the area in which DG develops, but also close to HV network, in order to ensure an easy connection to HV network. It will allow fulfill the following targets [61]:

- To connect high DG in a safer and more reliable way.
- To avoid lower voltage levels network saturation, mainly with regard to MV network.
- To reduce losses.
- To limit the environmental impact of new network facilities.

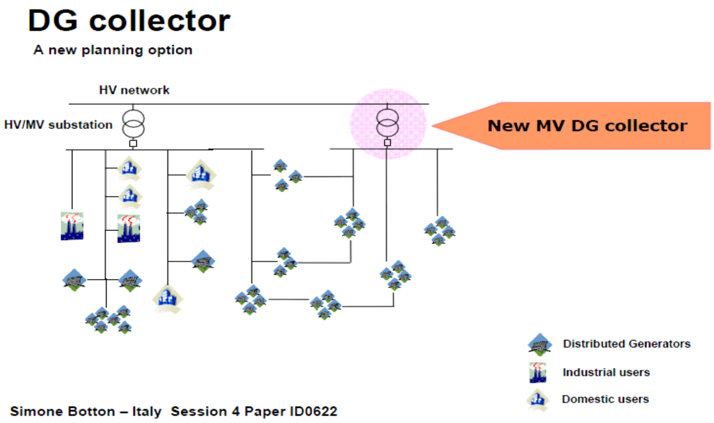



**Fig. 52 New network planning for high DER penetration (Italy)** [61]

## Norway

In order to confront the problems that arise due to the DER interconnection, the Norwegian DSOs are using several solutions, some temporary while others permanent. The following figure shows the answers given by the Norwegian DSOs to what solutions they are using to address the problems caused by DG connection. The solutions used are mostly temporary with special focus to temporary restrictions to production and network operation changes.

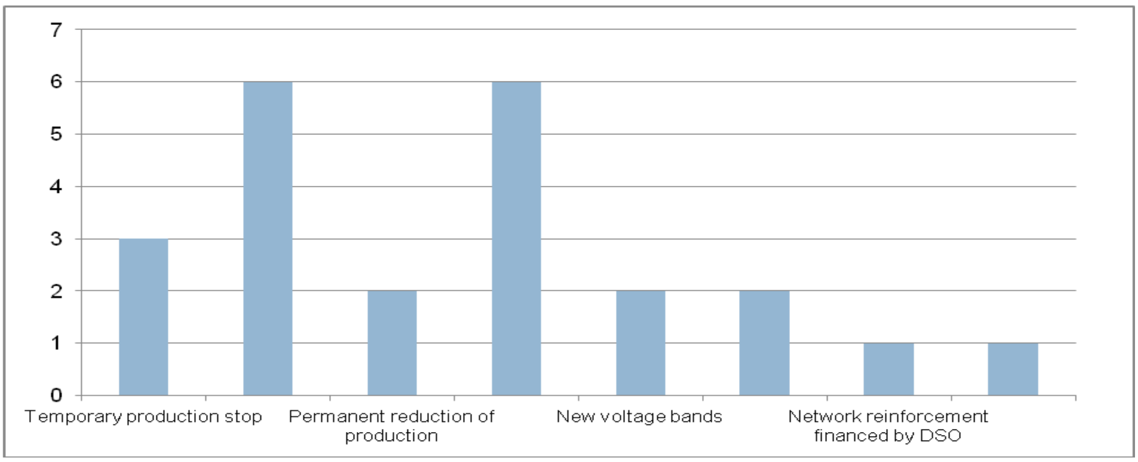



**Fig. 53 Solutions applied by DSOs to solve the problems caused by DER in the networks (Norway)**

In Norway, the typical solution when approaching the feeder capacity due to DER integration is to reinforce the network, either by increasing the feeder cross-section or upgrading the network to a higher voltage level. In some cases, where multiple connection points to the transmission network are possible, a redesign of the MV network in the area is an alternative. This alternative leads to going from one long MV feeder to several shorter feeders. However network reinforcements often require large investments and will in some cases make the DER development unprofitable for the DER owners.

Voltage regulation in MV networks is traditionally performed by on-load tap changers at the HV/MV substation. However, in situations with a high penetration of DER on a feeder, such tap changers are often not able to keep the feeder voltage below the upper limit, and additional voltage regulation on the feeder is required. In order to confront high voltages due to DER especially in weak MV networks without needing to reinforce the entire feeder, a voltage regulator is used which is designed to reduce voltages in the MV network during periods with high production from DER. The regulator utilizes a transformer in combination with controllable inductors to adjust the feeder voltage. It introduces a voltage step on the feeder and thereby enables the DER to insert more power without creating unacceptable voltages or large reactive power flows. A full scale prototype is currently being tested in a MV network in Norway with positive experiences so far.

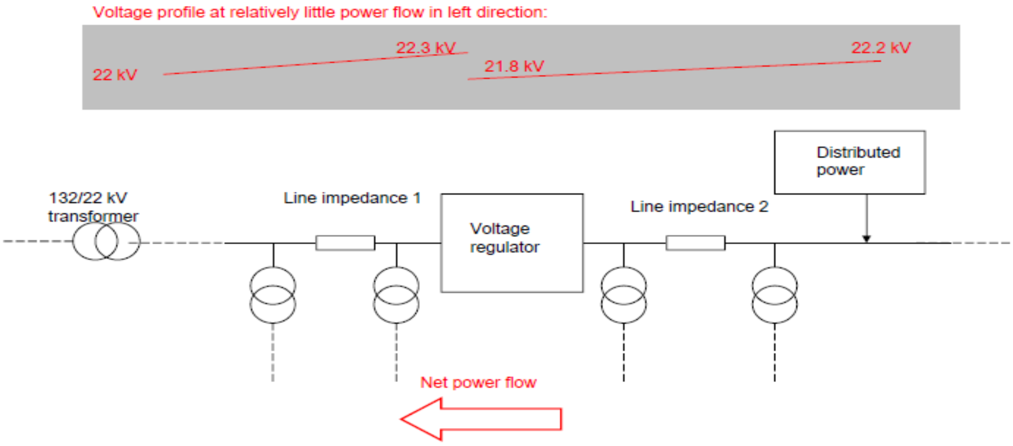



**Fig. 54 A presentation of the voltage booster. MV voltage booster prototype is currently being tested**

Another way to mitigate voltage rise due to distributed generation is to install reactive power sinks in the MV network. This could for instance be done by installing shunt reactors. Furthermore, transformers between the MV and LV networks are also equipped with tap changers. However, these are manually operated by the DSO and used only to adjust for seasonal load changes. A possible way to optimize the voltage profile on a feeder containing multiple DER and to reduce the amount of reactive power drawn from the transmission network is to coordinate the operation of the voltage regulators at the different generators. The benefits of such an operation strategy is described in [102], but it has not been tested in practice in Norway.

Finally, the most utilized measure at the DER side for increasing the feeder hosting capacity is to operate the DER in voltage control mode, and thereby consuming reactive power during high production. For instance, small hydro power plants of more than 1 MW, which have synchronous generators, could be set to consume reactive power in order to reduce the voltage in the MV network. This is done in many cases in order to increase hosting capacity. This is used in situations were minor network adjustments are needed to enable connection of DER. However, this results in increased network losses and increased strain on the generators.

## Spain

In order to limit interconnection currents and the caused voltage drops when the DER consists of asynchronous generators, reactances between generator and grid (they are short-circuited after the transient time) are proposed [16].

Both the reactive power and voltage control are ancillary services that can be used with clear benefits for the electric power system. Until 2004, when the RD 436/2004 was published, the request for the DER was to maintain the power factor as closer to the unity as possible, even if the usage of capacitors is inevitable (e.g. asynchronous generators). In the case of generators that can control power factor, the request was to provide an amount of reactive power in order to compensate the consumption of reactive power in the transformer and lines until the PCC. Since 2004 it is required for DER to control power factor through controlling reactive power depending on demand and voltage profile. The values of the power factor must lie within ±0.95. It is imperative that there must be an advanced coordination between DER and the automatic transformer tap changers so as the voltage regulation policy to be successful. At present, it is more feasible a dynamic reactive control to be implemented, depending on the generated power or the period of the day when voltage is expected to be high or low, than a voltage control with voltage metering feedback, which is not asked in the Spanish legislation. Briefly a power factor control policy should take into account the following paramaters [73]:

- SCADA and centralized control.
- Voltage metering.
- Fixed and On Load Tap Changers.
- Capacitor banks.
- Power Electronics Solutions.
- Power Factor Controllable Wind Turbines.

Moreover, a future step will be the coordination of DSO and TSO, so as an optimum power factor order to be sent to DER resulting also in minimization of the system losses.

Taking into account the mentioned restriction[21] in Chapter 2, related to wind power plants and the short circuit, the ability of controlling the voltage in transmission system, by the wind generators, decreases since the upper permitted[22] generated or consumed reactive power, which is around 30% of the active one, limits to no more than ±1.5% of the nominal voltage. If it is required the voltage to be controlled more successively, the restriction mentioned above should be modified so as the limit to be equal to 16.6% of the short circuit at the PCC.

## UK

The following outline the measures that can be taken by the DNOs so as to relieve the impact of penetration of DER on the network. In this way, the hosting capacity can increase. Some of these measures are cost effective and already implemented while others are under research and are not widely accepted [103]:

**<u>Short circuit</u>**

- <u>Uprate network components</u>: It may be difficult to assess the feasibility of uprating equipment for the following reasons:
    - The fault current capability of installed older equipment (including cables and transformers) may not be ascertainable.
    - The manufacturers of installed older equipment (including circuit breakers, cables and transformers) may no longer be in business, or unable (or unwilling) to advise on the feasibility of uprating or to confirm the actual capability of the equipment.
- <u>Increase impedance of components</u>: It is possible to specify a higher impedance for certain network and generator components (e.g. substation transformers, generator impedance). This will reduce the fault level and is a low cost solution for new installations, but is more costly or impracticable as a retro-fit option. Feasible measures are the following and are shown on the next figure:
    - Increasing generator impedance.
    - Increasing transformer impedance.

[21] The aggregated power must not be greater than 5% of the short circuit at the PPC
[22] The power factor must lie within ±0.95

- o Inserting impedance devices.

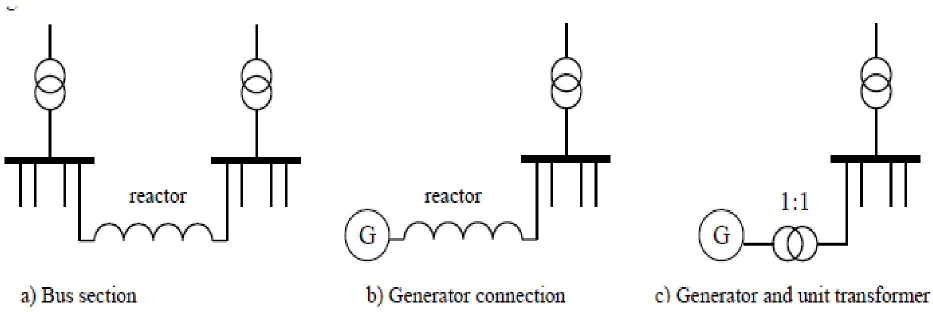



**Fig. 55 Addressing the short-circuit issue by increasing PCC impedance** [103]

- Network reconfiguration: Distribution networks are designed to allow their connectivity to be altered, either in response to a fault or to allow a section of network to be isolated for maintenance purposes. Thus, distribution networks contain switchgear which is either used to provide additional connectivity (a normally-open switch) or isolation (a normally-closed switch). Normally open switches are often found at the furthest point of an open ring or at a point where two feeders could interconnect adjacent substations. This topology is illustrated in Fig. 56.

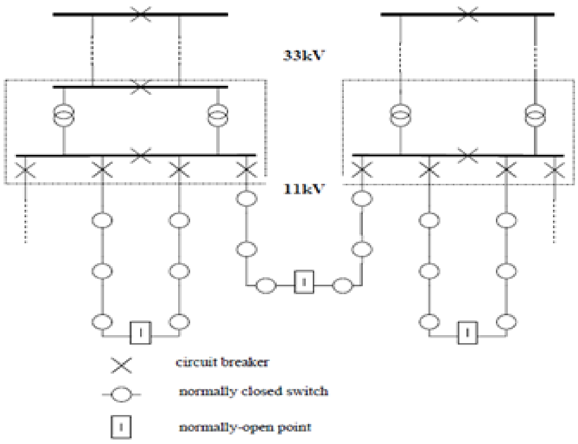



**Fig. 56 Addressing the short-circuit issue by making network reconfiguration** [103]

- Is Limiter***:*** Is Limiter (Fig. 57) is possible to increase the network impedance only at the time when the impedance of the network needs to be increased i.e. at the time when fault current flows. This can be achieved by the use of a device known as an Is limiter – a fault current limiting device. The key advantage of using such a device is that it retains the existing low network impedance under normal network conditions, and hence avoids any of the problems associated with increasing network security risks, losses and voltage control associated with permanently increasing network impedance.

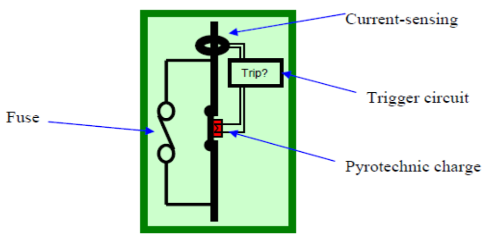



**Fig. 57 Addressing the short-circuit issue by using Is limiter** [103]

- Sequential switching: Sequential switching is a method by which the multiple sources contributing to any fault current are separated prior to the clearance of the faulted section. The sequential switching concept is explained in Fig. 58.

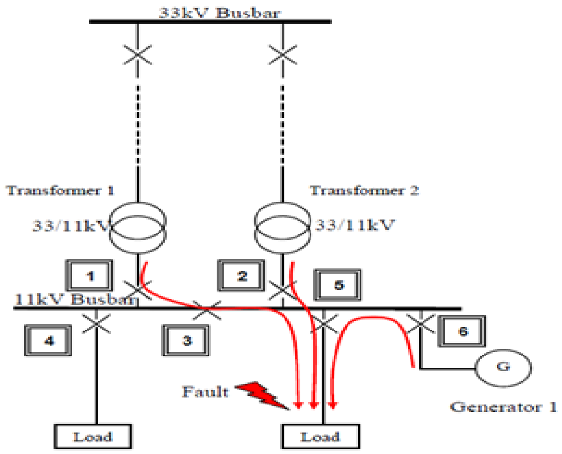



**Fig. 58 Addressing the short-circuit issue by implementing sequential switching** [103]

**Voltage**

- Line re-conductoring: Re-conductoring a circuit with a lower resistance cable or overhead line improves the voltage regulation along that circuit. This improvement is a direct result of the lower network resistance, and therefore increases the amount of distributed generation which can be connected.
- Dedicated line or network
- Line voltage regulation: The use of line voltage regulators can be viewed as an extension to active voltage control on the distribution network. Line voltage regulators can be placed strategically within a feeder, such that the voltage regulator and the generator work together to control the downstream voltage, whilst the existing substation OLTC and Automatic Voltage Control scheme (AVC) controls the rest of the passive network in the conventional manner. Line voltage regulators are used by several DNOs to help manage voltage profiles on long feeders.
- Cancellation CTs: The use of Cancellation Current Transformers (CTs) is a means to modify the OLTC AVC arrangements. Cancellation CTs can be used to remove the feeder with generation connected to it from the AVC control mechanism when Line Drop Compensation (LDC) is used. Cancellation CTs and their interface to the Voltage Control Relay (VCR) are already available from manufacturers (e.g. load exclusion module from VA Tech). The application of the technique would be limited by the number of circuits that could be ‘excluded’ from the control scheme whilst still maintaining voltage control on the remaining feeders as shown on the following Fig. 59.

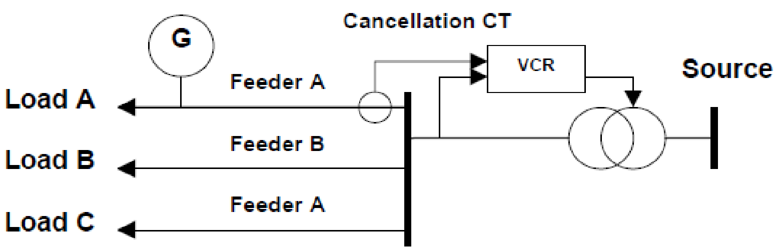



**Fig. 59 Cancellation CT and Line Drop Compensation (LDC)** [103]

As for the available means that can be implemented on the side of DER, the following outline some possible and feasible ones [103]:

- Generator reactive power control: Reactive power control is a technique commonly used in transmission networks to maintain voltage profiles along a line. Generally speaking, transmission lines tend to be longer than distribution lines and their X/R ratio higher. This means that reactive power control is not so effective within distribution networks, but nevertheless can provide some benefits.
- Generator real power control: Control of the generator power output can be a way of enabling more generation to be connected and increasing the overall financial performance of a development. If the level and frequency of generator curtailment is relatively small, then this can be a very attractive solution. In principle, real power control could be carried out in “real time”, although it could also be achieved more coarsely using a simple seasonal control.

# CHAPTER 4 – PRACTICAL RULES

Based on the information provided so far on the practices of several DNOs, rules of thumb and simplified evaluation methodologies are summarized in the following. It is worth mentioning that non-compliance with some of these rules doesn't necessarily entail rejection of the examined DER interconnection. Rather, detailed studies are typically required, at a subsequent level of more detailed technical evaluation, before passing a final verdict. Moreover, it is important to state that the following rules do not include all the applicable criteria mentioned in the previous Chapters but only those used as rules of thumb.

**Criteria related to or based on ratings/thermal limits**

- **(Belgium)** The aggregate power of DER must not exceed the HV/MV transformer power, taking into account that the N-1 criterion should be met.
- **(Belgium)** As for LV networks, the aggregate power of DER must not exceed the MV/LV transformer power rating.
- **(Canada)** The Thermal Capacity limit represents the estimated name plate amount of DER that can be added to that bus or station mainly based on the reverse flow limits of the transformer according to the following rule: Reverse power flow must not exceed 60% of station capacity (sum of 60% maximum MVA rating of the single transformer and the minimum station load).
- **(Canada)** For transformers rated less than 50kVA (typically 10kVA and 25kVA), the total connected generation capacity, including the proposed generation, must be limited to 50% of the nameplate kVA rating of the respective transformer winding.
- **(Canada)** For generators connected between line-to-neutral terminals of the transformer secondary, the total connected generation capacity shall not exceed 25% of the transformer nameplate kVA rating.
- **(Czech)** Available connection capacity at the 110kV/HV substations. The maximum accumulated power that can be connected to the HV network, including both existing and dedicated feeders, is roughly limited by the installed transformer capacity at N-1 conditions, plus the annual minimum substation load (correction coefficients may apply, further limiting the hosting capacity).
- **(Italy)** The aggregate nominal power of all DER must not exceed 65% of the nominal power of the HV/MV transformer.
- **(Italy)** The aggregate nominal power of all DER must not exceed 60% of the thermal limit of the feeders.
- **(Portugal)** The aggregate DER nominal power that can be connected to a MV/LV transformer should not exceed 25% of the nominal power of the transformer.
- **(South Africa)** The aggregate DER nominal power that can be connected to all shared LV feeders should not exceed 25% of the nominal power of the transformer.
- **(South Africa)** The aggregate DER nominal power that can be connected to a shared LV feeder should not exceed 25% of the circuit breaker rating.
- **(South Africa)** The aggregate DER nominal power that can be connected to a dedicated LV feeder should not exceed 75% of the circuit breaker rating.
- **(South Africa)** The aggregate DER nominal power that can be connected to a MV/LV transformer should not exceed 75% of the nominal power of the transformer.
- **(South Korea)** The aggregate nominal power of all DER connected to MV network must be lower than 20% of the HV/MV transformer nominal power. When the aggregate nominal power of all DER is less than 15% of HV/MV transformer nominal power, the proposed DER can be connected to the HV/MV transformer without detailed evaluation procedure.
- **(South Korea)** The aggregate nominal power of all DER connected to a MV feeder must not exceed the line operating limit (typically 10 MW). When the aggregate nominal power of all DER in a feeder is less than 15% of the line operating limit, the proposed DER can be connected into the feeder without detailed evaluation procedure.

- **(South Korea)** When the aggregate nominal power of all DER (including the proposed one) that are connected to a MV/LV transformer is less than 25% of the nominal power of the MV/LV transformer, the proposed DER can be connected to a shared LV feeder without detailed evaluation procedure.
- **(South Korea)** When the aggregate nominal power of all DER (including the proposed one) that are connected to a MV/LV transformer is less than 50% of the nominal power of the MV/LV transformer and the nominal power of the proposed DER is less than 25% of the nominal power of the MV/LV transformer, the proposed DER can be connected to a dedicated LV feeder without detailed evaluation procedure.
- **(Spain)** The aggregate nominal power of DER must be less than 50% of the thermal limit of the feeder where the DER will be connected to.
- **(Spain)** As for the transformers and the substations, the aggregated nominal power of DER must be less than 50% of their capacity.

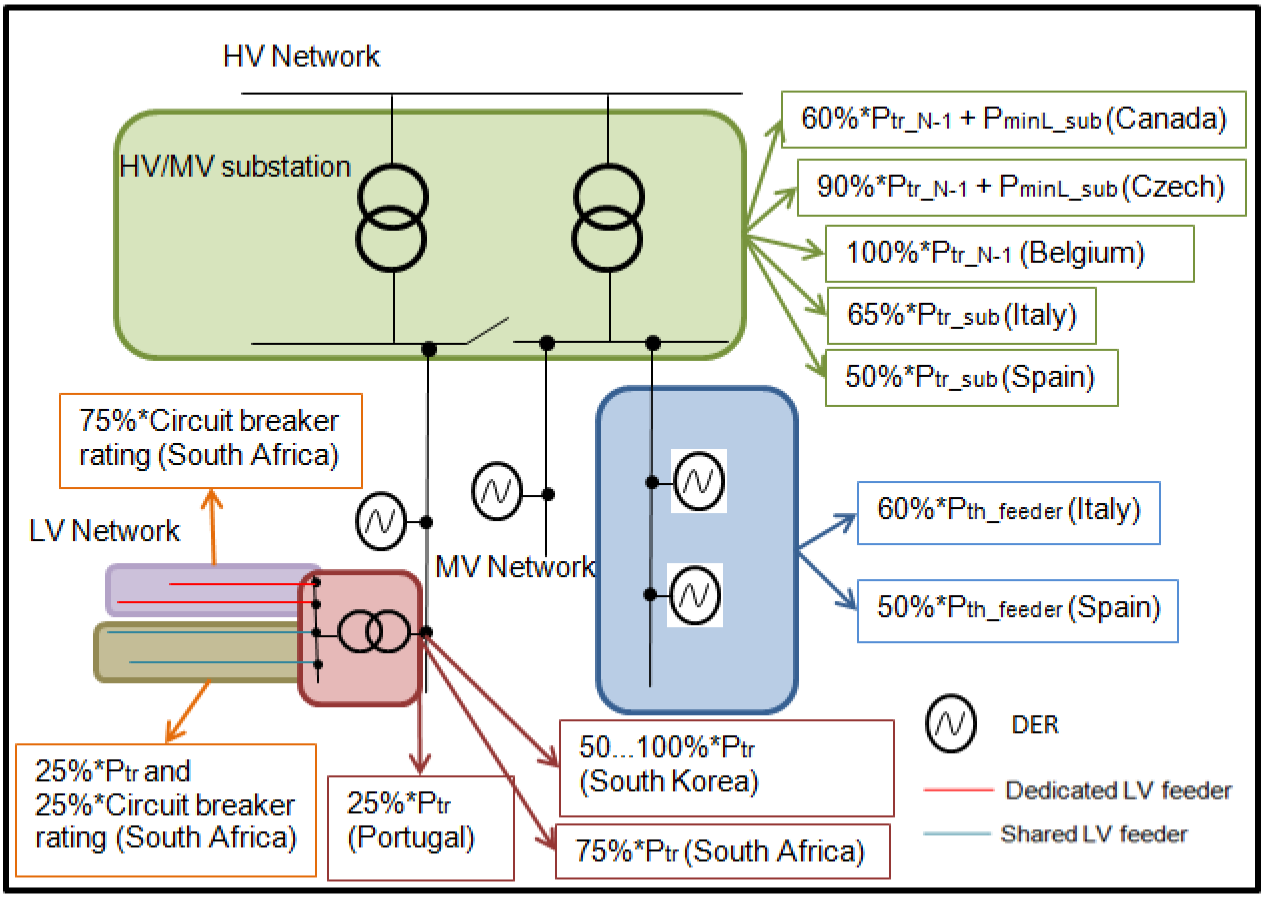



**Fig. 60 Criteria related to or based on ratings/thermal limits**

## Criteria related to or based on short circuit capacity

In general, all DNOs ensure that the eventual fault level, after considering all DER (and active loads) of the network, remains below the design short circuit capacity of the network and the short circuit withstand capabilities of individual equipment (e.g. make and break currents of breakers). Some DNOs (e.g. in the States) further require that a safety margin should remain available. For instance, all DER shall not cause any distribution protective devices and equipment, or customer interconnection equipment, to exceed 87.5% (or 85% or 90%) of the short circuit interrupting capability.

- **(China)** The aggregated nominal power of the connected DER must not be greater than 10% of the short-circuit at the PCC.

- **(South Korea)** When the aggregate nominal power of all DER is less than 15% of HV/MV transformer nominal power and the aggregate nominal power of all DER in feeder is less than 15% of the line operating limit, the proposed DER can be connected to the network without detailed evaluation procedure concerning short-circuit contribution.
- **(Spain)** The aggregate nominal power of the connected DER must not be greater than 10% of the short-circuit capacity at the PCC in order to avoid undesirable impact to power quality.
- **(USA)** The aggregate short circuit contribution ratio of all DER on the distribution feeder must be 0.1 (10%) or less. Otherwise, detailed studies are required.
- **(USA)** If the proposed DER is to be interconnected on a shared secondary, the short circuit contribution of the DER must be 2.5% or less than the interrupting rating of the DER's interconnection system.
- **(USA)** The SCC of the DER must be lower than 25% of the feeder short circuit at the DG location.

**Criteria based on the load-to-generation ratio**

- **(Canada)** Area load limit: Maximum allowable generation will be equal to a portion of the feeder or substation annual minimum load (typically 50%-100%) depending on the type of generation and the sophistication of the protection system
- **(Canada)** The total generation to be interconnected to a distribution system circuit line section, including the proposed generator, will not exceed 7% of the annual line section peak load on F-class feeders and 10% on M-Class feeders[23].
- **(South Africa)** The aggregate DER nominal power that can be connected to a MV feeder, including the DER that are connected to the LV feeders of this specific MV feeder, is limited to 15% of the feeder peak load.
- **(USA)** For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit shall not exceed 15%[24] of the line section annual peak load as most recently measured at the substation. Some DNOs apply this rule only for DER of 2 MW or lower. If this criterion is not met, there is a detailed evaluation procedure.
- **(USA)** The aggregate nominal power of the DER on the line section must be less than 100%[25] of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the generating facility. Solar generation systems with no battery storage use daytime minimum load (i.e. 10 am to 4 pm for fixed panel systems and 8 am to 6 pm for PV systems utilizing tracking systems). Other DNOs apply a stricter limit (50% of the minimum load).
- **(USA)** The aggregate nominal power of all DER on a feeder must be 5%[26] or less of the total circuit annual peak load as most recently measured at the substation. Other DNOs apply a less strict limit (7.5%). If this criterion is not met, there is a detailed evaluation procedure.
- **(USA)** If the DER is served by a three-phase four wire service or if the distribution system connected to the DER is a mixture of three and four wire systems, then aggregate nominal power of the DER must not exceed 10% of the line section peak load.
- **(USA)** In secondary network systems, aggregate DG should represent 25% or less of the total load on the network (based on the most recent peak load demand). This is the value at or below which inverter-based DG should not require costly changes to the utility system in order to accommodate the DG installation.

[23] See Note on page 70 for the rationale of this criterion
[24] See Note on page 70 for the rationale of this criterion
[25] See Note on page 70 for the rationale of this criterion
[26] See Note on page 70 for the rationale of this criterion

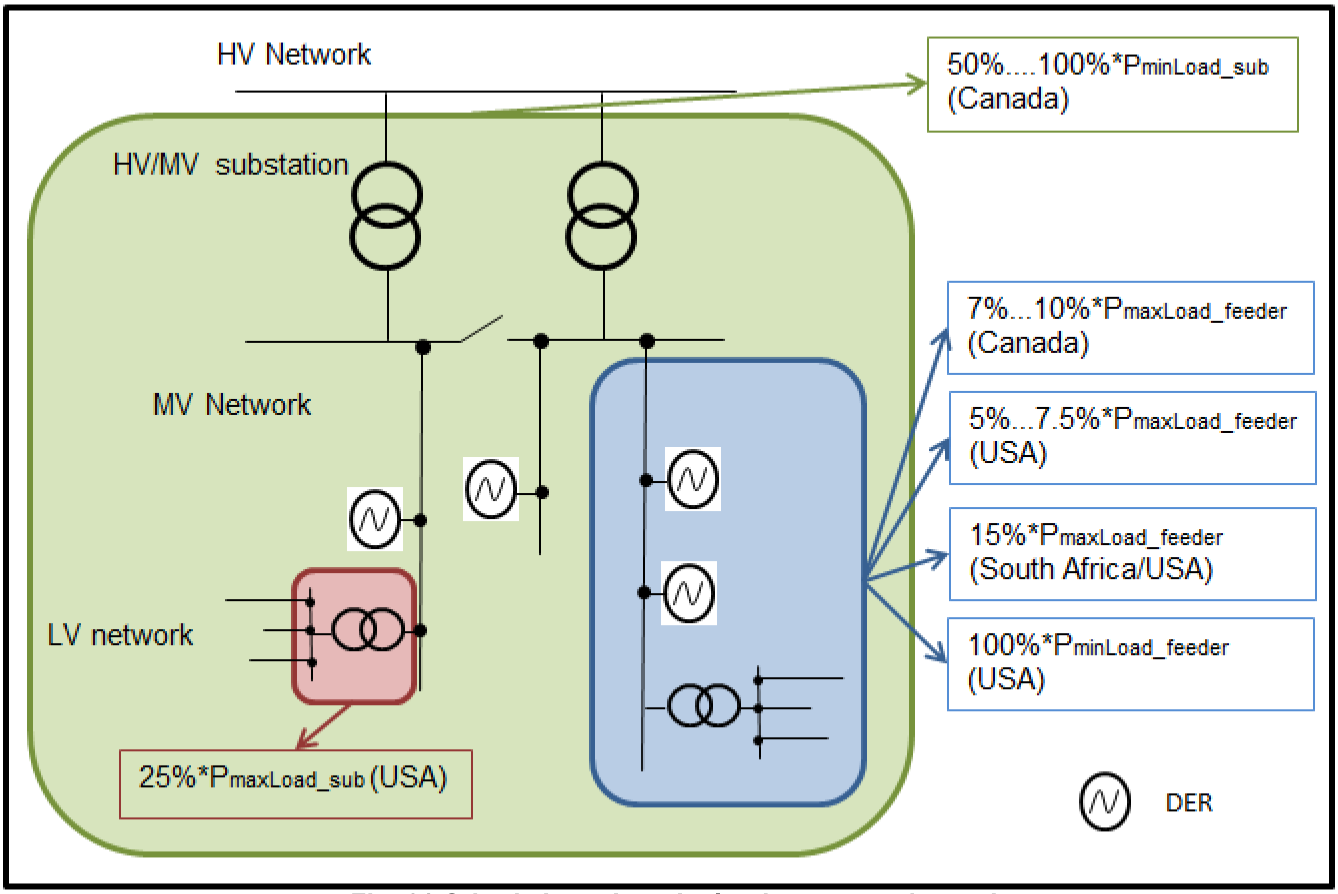



**Fig. 61 Criteria based on the load-to-generation ratio**

**Other criteria**

- **(Canada)** DER shall not increase distribution system electrical losses.
- **(UK)** 4 ≤ generator capacity (MVA) x distance from substation (km)
  For example, a 2 MVA generator can be connected up to 2 km from the primary substation or a 1 MVA generator can be connected up to 4 km away, etc.
- **(USA)** A proposed DER, in aggregate with other generation interconnected to the distribution side of a substation transformer feeding the circuit where the small generator facility proposes to interconnect, may not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity.
- **(USA)** When a proposed DER is to be interconnected on a single-phase shared secondary line, the aggregate generation capacity on the shared secondary line, including the proposed small generator facility, may not exceed 20 kW. If the aggregate generation capacity is in excess of 20 kVA, the voltage supplied to other customers who share the secondary conductors could exceed acceptable limits.

Regarding the means that are available to increase the hosting capacity, either from the DER side or from the DNO side, the information provided in the previous Chapter 3 is summarized in the following:

- **Shallow and deep connection works**:
  - Reinforcement, rearrangement or even construction of new network (LV, MV feeders, transformers etc).
  - Construction of new HV/MV substations of interconnection of DER only (DG Collectors).
- **Short-circuit**:

  - Usage of generator with lower fault current contribution, transformers with a higher impedance or fault current limiting reactor.
  - Upgrade of network equipment to meet the increased fault level.
  - Usage of sequential switching so as to reduce the fault current contribution of the connected DER.
- **Voltage regulation**:
  - Replacement of HV/MV transformers with others equipped with increased tap range and readjustment of control settings of OLTC and of MV/LV transformer fixed taps[27].
  - Replacement of the feeder capacitor banks with switchable ones, to avoid overvoltages.
  - Cancellation CTs to modify the OLTC settings.
  - Installation of reactive power sinks (i.e. reactors) on the network.
- **Other upgrades:**
  - Modifications so as to allow bidirectional power flow, such as replacement of breaker protection relays or reclosers etc.
- **DER control**:
  - Reactive power or power factor control[28].
  - Active power curtailment.
  - More effective anti-islanding protection schemes.
- **Future concepts**:
  - Usage of SCADA software or other (smart grids, web interfaces etc).
  - Decentralised storage used for peak shaving.
  - Coordinated voltage control on the distribution network (HV/MV and MV/LV substations and voltage regulators on the feeder).

[27] Installation of MV/LV distribution transformers equipped with OLTC has been also proposed.
[28] There is a variety of ways that this method may be implemented. For instance, setting the power factor to a suitable fixed value and regulating the power factor as a function of active power generation or setting the reactive output power as a function of PCC voltage.

# CONCLUSIONS

The primary goal of this technical brochure is to summarize rules, methodologies and guidelines applied by DNOs worldwide to determine the hosting capacity of distribution networks. Within this framework, the main technical issues and limiting DER penetration levels have been summarized, evaluation practices and simplified criteria adopted in numerous countries have been presented and means employed to increase the hosting capacity of networks have been reviewed. The focus was always on practical and easy to apply methods, as well as on means and solutions currently applied, rather than on research grade solutions, which may become suitable for application in the future.

Technical factors limiting DER interconnection capacity to the distribution networks include:

- Thermal rating of network equipment, such as transformers and feeders, are always an important consideration.
- Voltage regulation, mainly voltage rise, is one of the most important problems faced at high DER penetrations.
- Increased fault levels, due to the contribution of DER, is also an important limitation, particularly for MV networks.
- Reverse power flows, that may affect adversely the operation of voltage regulators and tap changers, impact on network losses and reliability, power quality related issues, islanding considerations and impact on the operation of network protection are additional technical constraints limiting the hosting capacity of feeders and distribution networks.

Criteria applied by DNOs for the determination of hosting capacity, especially in the form of simplified rules and guidelines, can be separated in the following main categories:

- Criteria based on the installed tranformer capacity of HV/MV and MV/LV substations and the thermal limits of MV and LV feeders are typically applied, including N-1 considerations at substation level and possibly the reverse power flow capability of transformers.
- Criteria related to the short circuit capacity are also quite popular and relatively easy to implement. They ensure that the design fault level of the network is not exceeded, or they simply provide a maximum permitted DER capacity as a ratio of the fault level at the PCC.
- The load-to-generation ratio also forms the basis of simplified connection rules, derived either from islanding prevention considerations or voltage regulation problems.

Means commonly employed to increase the hosting capacity of networks include:

- Reconfiguration, reinforcement, upgrade and expansion of network installations is common practice to resolve capacity limitations, voltage regulation and short-curcuit level issues.
- Application of modified and improved voltage control schemes is also standard practice, within HV/MV substations, in line voltage regulators and switched capacitors.
- Reactive power or power factor regulation of DER is being increasingly implemented, to mitigate voltage regulation issues.
- DER active power curtailment is also a possibility to resolve voltage regulation and local congestion issues, though it is always a last resort due to its economic implications to the DER investment.
- Decentralised storage, demand response and coordinated voltage control practices are envisaged as future options, when the necessary conditions will be favourable for their deployment (smart-grid infrastructure, electricity market and regulatory framework, technical maturity etc.).

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# ANNEXES – CASE STUDIES

## Annex A – Austria

The aim of this annex is to outline the assessment of the impact on the network by the connection of DER emphasizing mainly on issues related to voltage [17].

Let's consider the following network.

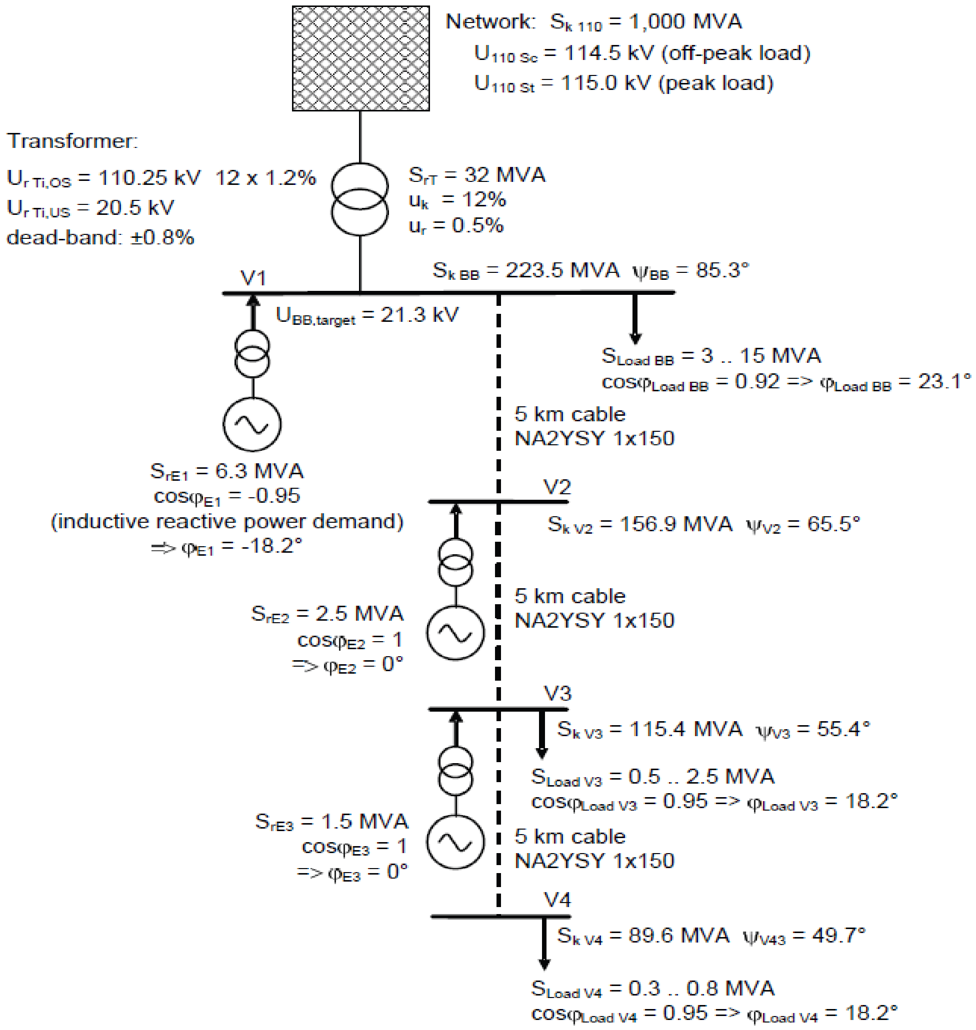



**Fig. 62 MV network used in a DER interconnection case study** [17]

In the network illustrated in the above figure, the DER 1 and 2 are already connected to the bus 1 and 2 respectively while the DER 3 is to be connected to the bus 3. In order to verify the compliance with the permitted voltage rise and the limits set in EN 50160, the calculation of the voltages of all nodes of the network is required. This has to be done in the cases with minimum and maximum load and with minimum and maximum infeed by the DER. The characteristics and all relevant data that are required for the above mentioned assessment are shown on the above figure. Taking into account the operation of the on load tap changer which is regulated to maintain the voltage at the busbars steady at 20,5 kV having a deadband equal to 0,8%, power flow calculations are carried out resulting in the voltage values that are shown in the following Table 28 [17].

**Table 28: Voltage values in each node in four extreme cases** [17]

| | | V1 | V2 | V3 | V4 |
|---|---|---|---|---|---|
| Min Load | Without Generation | -0,19 % | -0,33 % | -0,51 % | -0,57 % |
| Max Load | | 0,48 % | -0,33 % | -1,15 % | -1,35 % |
| Min Load | With Generation | 0,67 % | 1,58 % | 1,92 % | 1,92 % |
| Max Load | | -0,4[29] % | 0,52 % | 0,87 % | 0,87 % |

The rows that refer to the cases with the power generation by the DER, show how much the voltage differs from the equivalent values that are derived by the cases without generation. In other words these rows show the voltage rise (variation) which is caused by the DER only. The maximum voltage rise is 1.92% which is smaller than the upper limit of 2%. Moreover, the maximum and minimum values of voltage in all nodes remain within the limits set in EN 50160. Taking into account the evaluation of the results the connection of the DER 3 is approved.

# Annex B – Canada

## B.1 – 1st Case Study

The following case study elaborates the problems that arise, the reasons and the possible solutions implementing and meeting the 5 mentioned criteria related to voltage regulation, in Canada [31].

**Problems - Reasons**

Let's consider the following network in which both DG2 and DG3 are to be connected while DG1 is to be connected in the future after DG2's and DG3's connection [31].

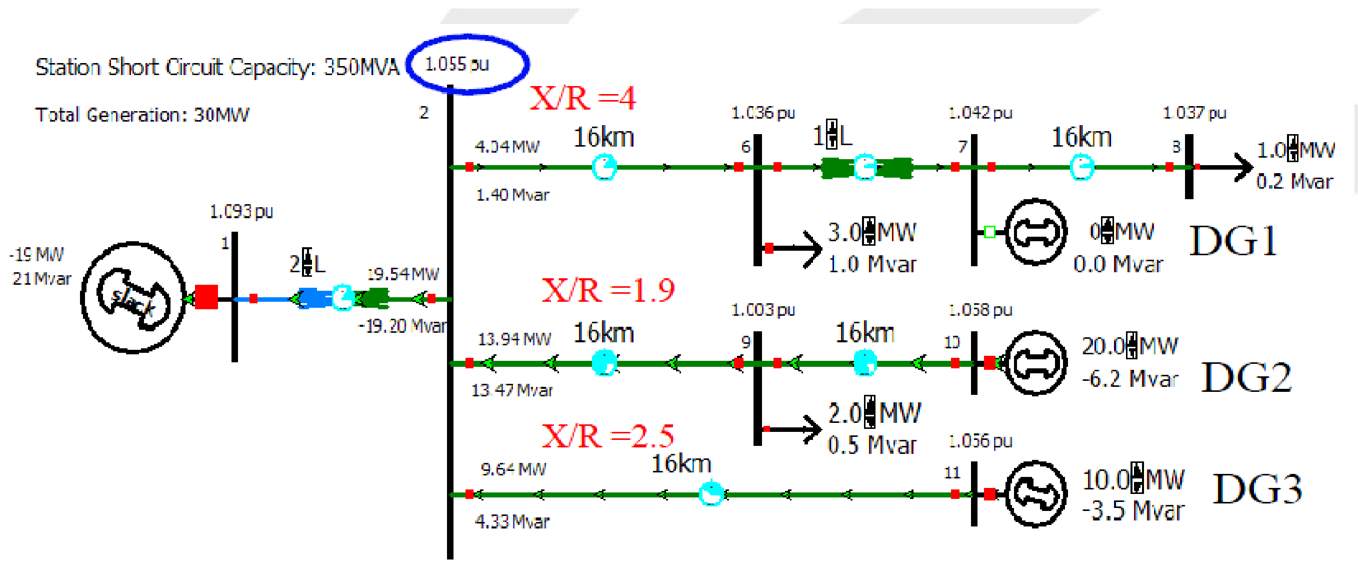



**Fig. 63 MV Network used in a DER interconnection case study** [31]

29 The negative voltage rise derives from the reactive consumption of the DER 1 which causes such voltage drop in the windings of the transformer which in comparison with the voltage rise, caused by the aggregated generation, is bigger.

Due to the low X/R ratio of the second feeder, the DG2 has to consume more reactive power than usual[30] so as not to violate the upper permitted voltage limit of PCC. In this way, indeed, the voltage at the PCC is 1.058 which means that it remains smaller than 1.06. So the one condition of criterion 2 is met. As for the second part of criterion 2, the voltage of the load on the second feeder decreases[31] (1,003) comparing with the equivalent value when the DG2 is not connected (see the following Fig. 63). So the criterion 2 is not met fully. Moreover the criterion 3 is not met as well. As a result, the DG2 violates both criteria 2 and 3 [31].

Let's consider that for one reason DGs trip. The following figure shows the caused voltage levels and power flows (post-contigency situation) [31].

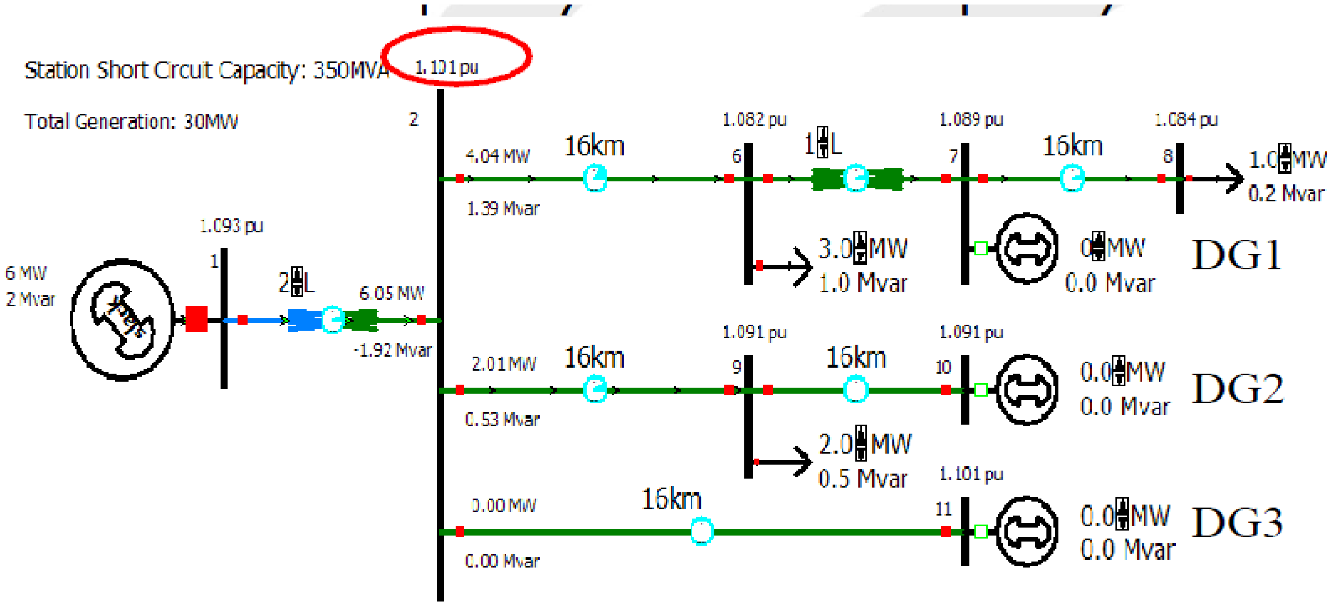



**Fig. 64 MV Network used in a DER interconnection case study** [31]

As a result the voltage at the bubars of the HV/MV substation exceeds the upper permitted limit which is 1.1 (110%). So the criterion 5 is not met also besides the criteria 2 and 3.

**Solutions**

The DNO lowers the permitted size of the DG that is to be connected at the end of the second feeder. In this way, as we can verify, another DG can be connected to the first feeder (DG1). The following figure shows the caused voltage levels and power flows [31].

[30] See comments on criterion 3 in Chapter 3 (Canada)

[31] If we consider stable voltage at the busbars (1,055) the load voltage before the connection of DG2 is 1,091-(1,101-1,055)=1,045. So, there is a decrease of 0,042 p.u.

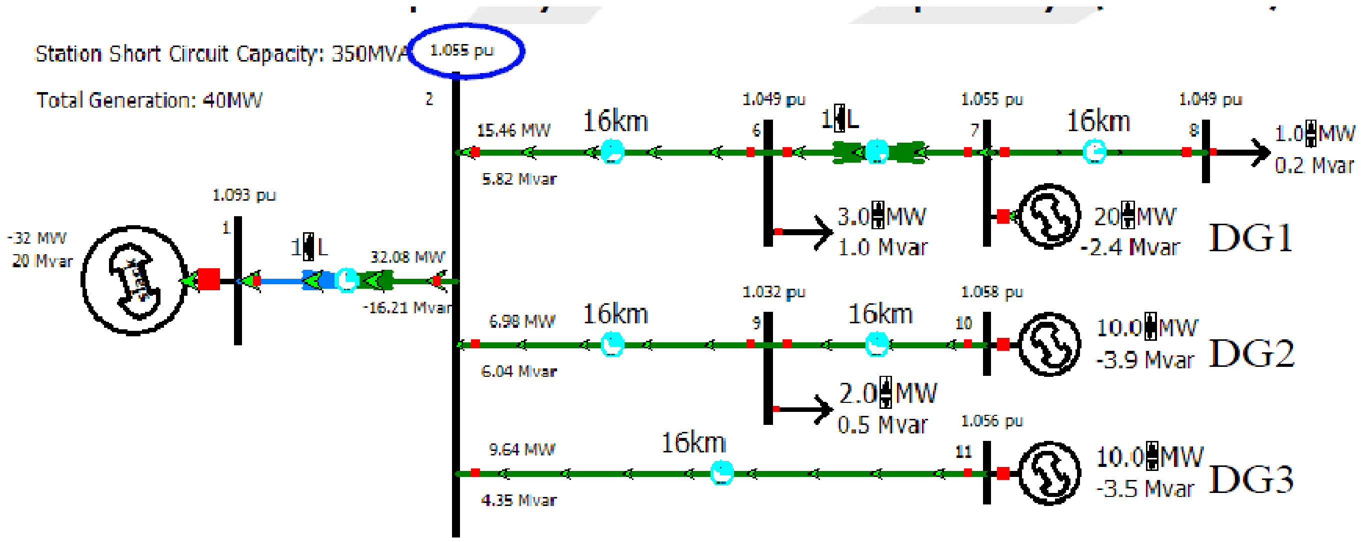



**Fig. 65 MV Network used in a DER interconnection case study** [31]

As we can see the upper permitted voltage limits are not violated. The decrease of the load voltage due to the connection of DG2 is very small[32]. Moreover the criterion 3 is also met.

Let's consider that for one reason DGs trip. The following figure shows the caused voltage levels and power flows (post-contigency situation) [31].

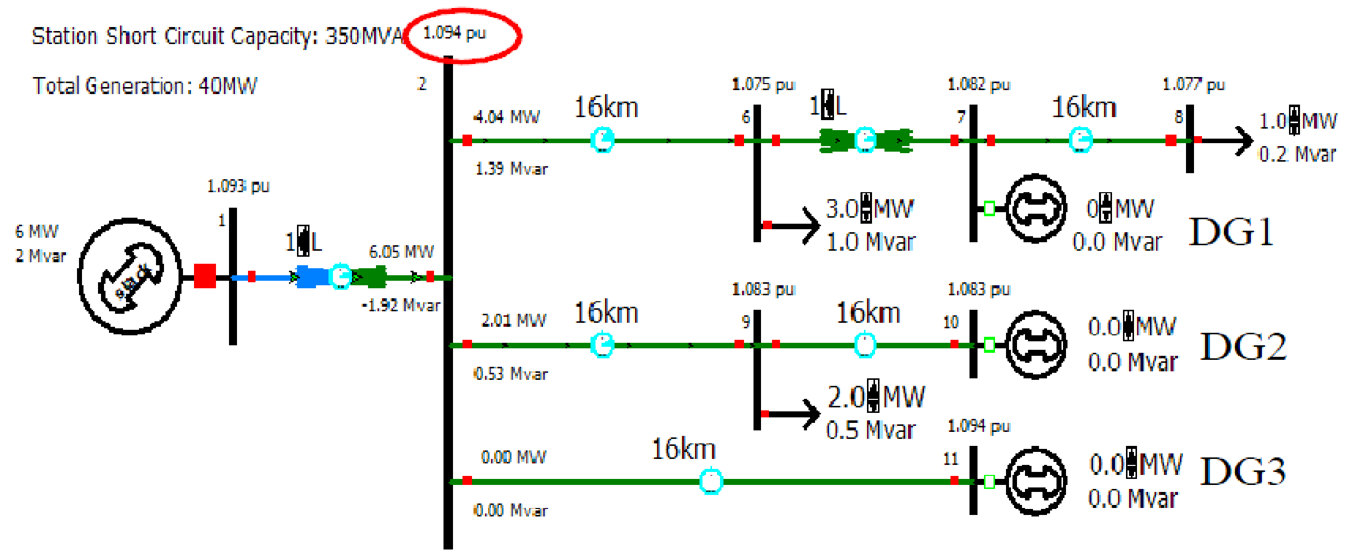



**Fig. 66 MV Network used in a DER interconnection case study** [31]

The voltage at the busbars still lies within the permitted range which means that the criterion 5 is also met.

[32] If we consider stable voltage at the busbars (1,055) the load voltage before the connection of DG2 is 1.083-(1.094-1.055)=1.044 which is very close to 1,035.

**Conclusions**

At the beginning, trying to connect the DG2 results in not connecting DG1 and severe problems related to voltage. Even if there was no problem with voltage regulation, the total connected power could not be greater than 30 MW as shown on the Fig. 62.

Lowering the power of DG2, DG1 can be connected and at the same time no problem arises related to voltage. As a result, the aggregate connected power on the substation is 40 MW as shown on the Fig. 64. Thus the aggregate connected power increases 25%.

According to [31] the example emphasizes that non-compliance with the voltage performance criteria at the feeder will constrain DG capacity at the station level.

### B.2 – 2nd Case Study

The following example is provided for the consolidation of the technical methodology that is applied, so as the DNO to assess if there is sufficient capacity for the connection of a DER, which is to be connected [34].

**Step 1 - New Proposed Generator Data**

Name plate capacity = 10 MW

Short Circuit Contribution = 25 MVA

Feeder = M1

**Step 2 - List of Station Capacity**

**Table 29: List of Station Capacity** [34]

| Station Name | BUS Name | Feeder Name | Voltage (kV) | Minumum Load (MW) | Short Circuit Capacity (MVA) | Thermal Capacity (MW) | Upstream TS | Upstream TS feeder |
|---|---|---|---|---|---|---|---|---|
| SAMPLE4 TS | Total | M1, M2, M3, M4, M5, M6, M7 | 27.6 | 30.0 | 70.0 | 60 | | |

**Step 3 - List of Applications**

**Table 30: List of Applications** [34]

| Project Number | Tx Station | Tx Feeder | Dx Station | Dx Feeder | Application Date | Name Plate Capacity (kW) |
|---|---|---|---|---|---|---|
| A | SAMPLE4 TS | M1 | | | 8/5/2008 | 10,000 |
| B | SAMPLE5 TS | M2 | | | 10/31/2008 | 10,000 |
| C | SAMPLE5 TS | M3 | | | 9/20/2009 | 10,000 |

**Step 4 - Station Capacity Availability Check**

Thermal Capacity = 60 MW (Table 29)

Short Circuit Capacity = 70 MVA (Table 29)

Allocated Capacity on Station = Project A = 10 MW (Table 30)

Assume Short Circuit contribution for allocated capacity to be 5 times the nameplate capacity (i.e. sub-transient reactance of 0.2 p.u.)

Short Circuit Contribution by allocated capacity generation = 5 X 10 = 50 MVA (13)

1. **Thermal Capacity Check = 60 – 10 (allocated) – 10 (new proposed) = 40 MW OK**
2. **Short Circuit Capacity Check = 70 – 50 (allocated) – 25 (new proposed) = - 5 MVA NOT OK**

**Conclusion:**
*The answer is positive for the thermal capacity check so the proposed generator is within the thermal capacity limit. The answer to the short circuit capacity check is negative. The proposed generator exceeds the short circuit capacity of the station.*

## Annex C – China

For instance, let's say that there is a 35kV substation which is equipped with two main transformers of 20 MVA nominal power. To make it simpler, the total load of the substation is divided into two parts, the load supplied by the transformer (PL1), and the load supplied by DER (PL2).

According to the 1st bullet of the 2$^{nd}$ Chapter (Section "China"), the load ratio of the substation should be at most 65% (PL1=26 MW). This means that in the worst case for the substation, which is when the DER do not generate any power (PL1+PL2≤26MW), the load ratio of the substation can reach the maximum of 65% (0.65*2*20=26MVA). This derives from the fact that a transformer can reach the allowed maximum of 130% (1.3*20=26 MVA) in overload operation when the second transformer is out of service (according to the N-1 criterion).

According to the 4th bullet of the 2$^{nd}$ Chapter (Section "China"), the load ratio of the substation has to be at least 50% (PL1=20 MW, cosφ=1). This means that in the best case for the substation, which is when the DER generate their nominal power, the load ratio of the substation can reach the minimum of 50% (0.5*40=20 MVA).

Combining the two mentioned criteria, the DER capacity can be determined. In this case, the load supplied by DER (PL2) is 6 MW (cosφ=1), so the corresponding maximum capacity of DER is 6.67 MVA (The output active load of DER is 6 MW when the generating power factor is 0.9). The total capacity of DER is equal to the 25.6% of the maximum load of the substation. This ratio is 25.5% when the substation has three transformers and 27.8% when the substation has four transformers.

## Annex D – Czech

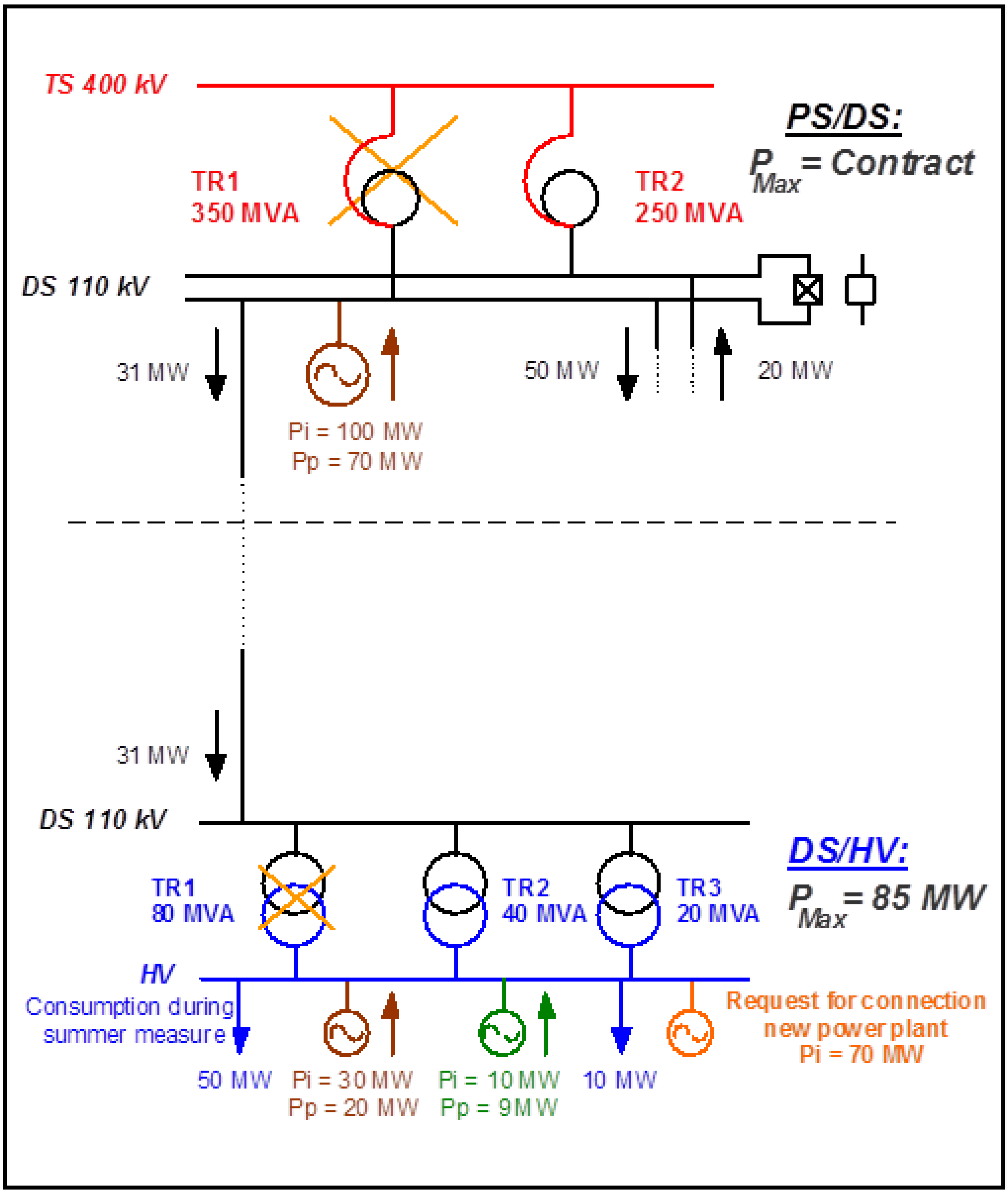
The aim of this annex is to show how the capacity in a substation can be calculated. The capacity for the connection of new power plants to the TS/110kV feed-in node is set in the contract between the TSO and the appropriate DSO with regard to the connection point, reliability of the TS/110kV transformation and regulation capabilities of the Czech power system, for which the TSO is responsible. Here, the feed-in node (voltage controlled bus) means the TS/110kV substation, from which electricity consumption of a given area is covered.

The maximum connectable power in HV network is then calculated using the relation $P_{Max} = (\sum P_{i(N-1)} * k_{tr} + P_{Bilance}) * k_e$ , as shows the following figure:

$$P_{Max} = (\underbrace{(40 + 20)*0.9}_{\textit{Transformer capacity}} + \underbrace{(50+10-20-9)}_{\textit{(Consumption – power production)}})*1 = 85\ MW \quad (14)$$

In this case study, the producer applies for a connection of the installed power of 70 MW. This connection in the HV node concerned is possible, considering the available capacity of the 110kV/HV substation (85 MW).

However, if in our case either there is insufficient capacity of the TS/110kV substation in the feed-in node which is set by conditions of the contract between the TSO and the DSO or if there is insufficient distribution capacity for the transport of power through the 110 kV network, then this generator cannot be connected.




<u>Legend</u>: $P_i$ = *installed capacity*

$P_p$ = *power production*

**Fig. 67 HV and MV network used in a DER interconnection case study**

## Annex E – Denmark

The aim of this annex is to analyse the integration of Solar PVs in the typical Danish LV networks (Case study on Solar PV integration in Danish Residential Grid [104]).

This case study is based on a low voltage residential grid located at Braedstrup, in Denmark [104]. The distribution feeders are normally operated in meshed topology and has a total of 60 residential customers connected to it. The rated capacity of the LV transformer is 400kVA. The average distance from the transformer to the households is 415.5m. The feeder cable types (underground) used are 3x240sq.mm Al, 3x150sq.mm Al, 3x95 sq.mm Al and services cable type is of 4x50 sq.mm Al. To estimate a worst case scenario of adding solar PV per household, the loops of the grid are disabled to form a radial network. With no reactive power (Q) control applied, Fig. 68 shows a case where the upper limit of the voltage is violated for a longer radial feeder with a maximum of 5.2kW PV power supplied per household as when compared to the meshed configuration of the grid.

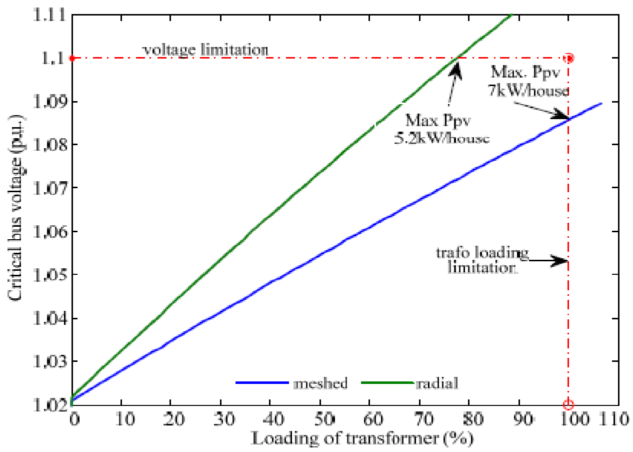



**Fig. 68 Solar PV integration levels without Q control and grid constraints** [104]

In this case study, static reactive power (Q) control methods like fixed cosφ , cosφ(P) and cosφ(P,U*)* using the solar PV inverters are applied for the local grid voltage support [47], [105]. A minimum power factor of 0.9 is considered which is based on the relevant grid codes for the LV grids. Table 31 and Fig. 69 illustrate the maximum injected PV power per household corresponding to various Q control methods applied. By applying these strategies, the voltages stay within the nominal limits, whereas the transformer capacity overloading becomes the limiting factor for higher PV power injection than over-voltages. An additional 30% of PV capacity can be integrated to the grid using the cosφ(P,U) method where the less voltage sensitive inverters in the close vicinity of the transformer are also forced to draw less reactive power.

**Table 31: Solar PV penetration levels in the radial LV network with different Q control methods** [104]

| | Max. Ppv (kW/house) | Trafo loading (%) | Critical bus voltage (p.u.) |
|---|---|---|---|
| No Q | 5.2 | 74.6 | **1.1** |
| cosφ=0.9 | 6.3 | **101** | 1.074 |
| cosφ(P) | 6.5 | **101** | 1.079 |
| cosφ(P,U) | 6.8 | **101** | 1.086 |

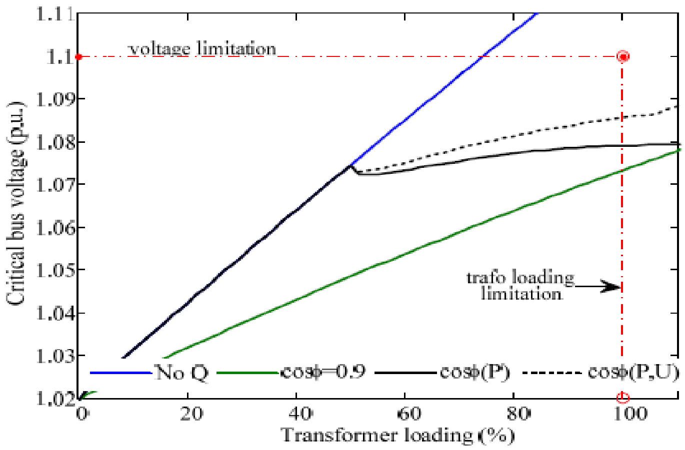



**Fig. 69 Estimation of PV penetration in the radial distribution grid with different Q control methods** [104]

# Annex F – Germany

## F.1 – 1st Case study

Throughout the last years, an increased number of violations of the voltage band according to DIN EN 50160 appears in Germany, due to the very high pv penetration to the grids. This currently requires the expensive replacement of existing cables or overhead lines. Off-load tap changers for voltage regulation may only be operated in de-energized condition and most likely they are not the future technical solution to solve the problem with large intra-day variations of load and generation, especially with the expectation of an increasing number of electric vehicles (EV). Thus, new technological options for voltage control in distribution grids need to be worked out.

**Motivation and goal**

Different technological options to control the voltage in low voltage distribution grids are under discussion and are being investigated in different research projects such as [106]. On-load tap changers or power electronic voltage controllers in secondary substations, voltage regulating transformers, reactive power compensation as well as active and reactive power control of decentralized generation units are technically feasible. However, development of corresponding products and their installation are hindered by the knowledge about actual demand and required parameterization.

Thus, this paper firstly introduces a methodology for modeling distribution grids as well as scenarios for future PV installations in Germany. Secondly, the main results and the expected need for voltage control in secondary substations are presented.

The goal is to derive guidelines under which circumstances, voltage control in secondary substations is a technically feasible and economically reasonable option as compared to classic grid reinforcement. Moreover, the goal is to approximate the number of voltage controlled substations to be required in Germany until 2030.

**Methodology**

The assessment of demand for voltage control in secondary substations in Germany requires adequate grid and calculation models that enable us to derive representative results.

**Grid model**

All results presented in this paper are based on calculations with synthetic low voltage grid models. As described in [107], synthetic grid models have been generated based on statistical information about German LV grids and can therefore be considered representative for the entirety of German LV-grids. The grid data used describes 9 different types of grids, taking into account the load density, the typical types of buildings (rooftop area etc.), the load characteristics and an appropriate number of EV. Load flow calculations using MATPOWER [108] have been used to determine asset utilization and voltages. The model has been applied to 9.000 synthetic grid models (1.000 of each type of grid), representing in detail the variety of real LV grids.

**Stochastic load and generation models**

In order to determine future voltage quality and to derive required counter-measures, adequate load and generation models (stochastic) are required.

**Load profiles**

Load profiles are generated based on statistical data about several household characteristics (Probability of possession of 26 most common household appliances,typical time of use (time of day), frequency of use, typical power consumption, duration of use).

Algorithms described in [109] are applied to this information in order to derive several household load profiles (different but typical ones), which show typical power consumptions for individual households and therefore enable for a realistic voltage calculation as required. An example is shown in Fig. 70 in comparison to a typical PV feed-in on a summer day.

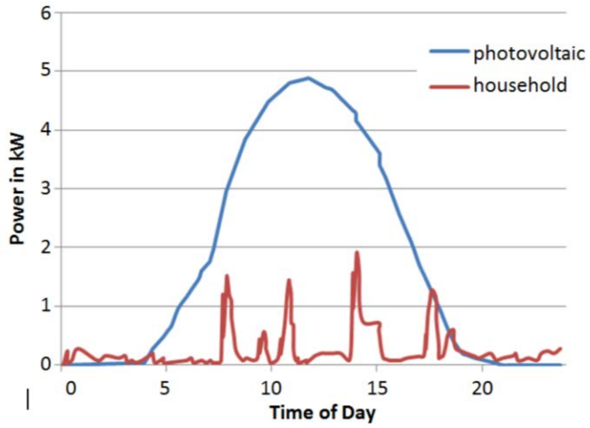



**Fig. 70 PV Feed –in and household load in summer**

**Generation profiles**

PV feed-in is calculated with a model for PV panels and power inverter, taking into account global solar radiation[33], area of PV panels as well as the efficiencies of PV panels (15%) and inverter (95%). Fig. 70 shows two different radiation profiles for a summer day in Germany. These represent extreme weather conditions for Germany (maximum global solar radiation to be expected). Two scenarios are introduced – a "non-volatile" scenario representing a sunny day in summer and a "volatile scenario" representing a summer day with clouds moving over the solar panel throughout the day.

[33] Global solar radiation is known from the so called "test reference years" (TRY) for 15 different regions in Germany

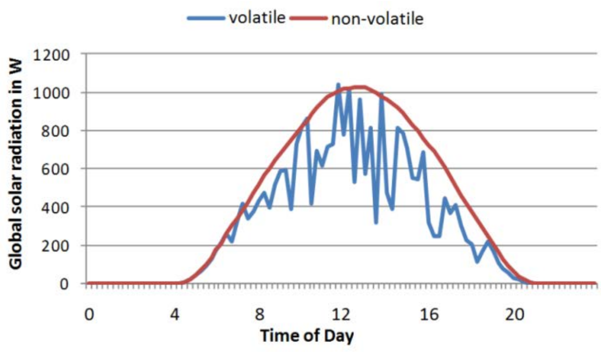



**Fig. 71 Global solar radiation profiles**

**Temporal resolution and stochastic variation**

Both load and generation data sets have been created in 15 minute resolution, which has proven to be an acceptable trade-off between calculation time and accuracy of the results. Load and generation profiles are assigned to the grid models on a random basis, while taking characteristics like the size of roof-tops etc. into account.

**Parameter variation and scenario definition**

The approximation of the number of voltage-controlled secondary substations to be installed in Germany until 2030 requires the definition of future scenarios for the growth of decentralized generation on LV grid level. Two kinds of scenarios have been worked – a set of future PV scenarios and a worst case approach allowing for a more detailed look at fields of application for voltage-controlled secondary substations.

*Future PV scenarios*

As shown in Fig. 72, two different scenarios have been examined, each providing different future developments of PV installations in rural, urban and sub-urban areas.

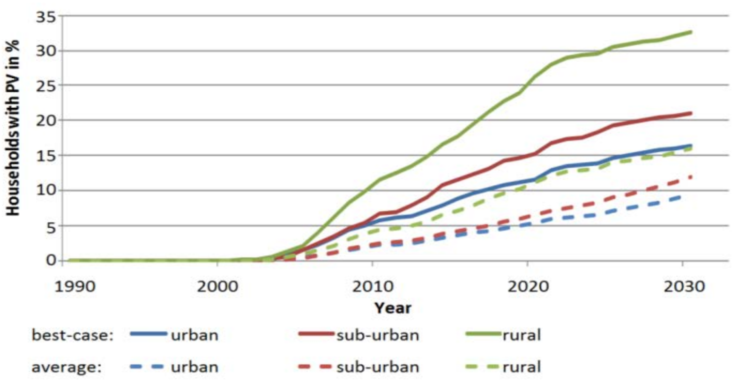



**Fig. 72 Scenarios for pv installation until 2030**

Both the best-case and the reference scenario are dominated by installations in rural areas, where in 2030 32% (best-case) and 16% (reference) of all houses are expected to have PV panels installed on the roof-tops. Only 9% (reference) or 16% (best-case) are expected in urban areas. Calculations for future PV scenarios have been carried out for 3 exemplary medium voltage grids (rural, urban, sub-urban, real grid data), combined with synthetic LV grid models, due to a lack of a full data set (real data of MV+LV grids). All PV systems are assigned to the grid randomly.

*Worst-case examination*

The so-called “worst-case” is introduced to examine the effects of different places of PV installation in low voltage distribution grids. While a purely random approach of assigning PV to households within the given grid models has been used in the previous steps, the PV installations are now assigned to the different feeders of the LV grids as described in Fig. 74. Case a) describes a grid model with PV equally assigned to households connected to the different feeders supplied by a substation, case b) does so for electric vehicles. Case c) describes a random assignment to the different feeders. Case d) actually describes the worst-case (Fig. 74) situation to be handled by voltage-controlled secondary substations with only one actuator for regulating the voltage on all feeders (which is the most likely case for the near future where OLTC-based solutions can be expected to dominate the market). For this configuration a spread of the voltage band is expected, limiting the range of OLTC actions (Fig. 73).

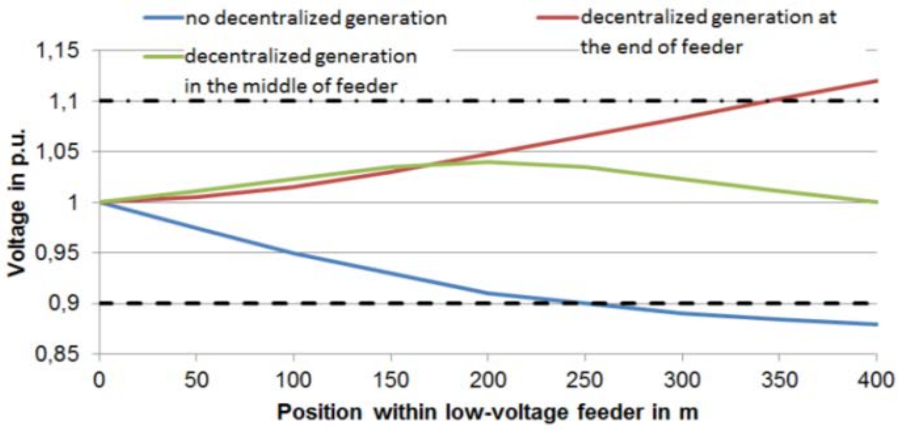



**Fig. 73 Exemplary voltage profiles**

All cases have in common, that PV systems are linked to the grid “from the end of the feeders”. Those cases are examined in the calculations, where lines remain just below the maximum allowable load, in order to only consider those cases where no replacement of lines is required.

In contrast to the future PV scenarios, these calculations have been carried out for 9.000 synthetic LV grid models, representing a greater variety of grids, but LV level only.

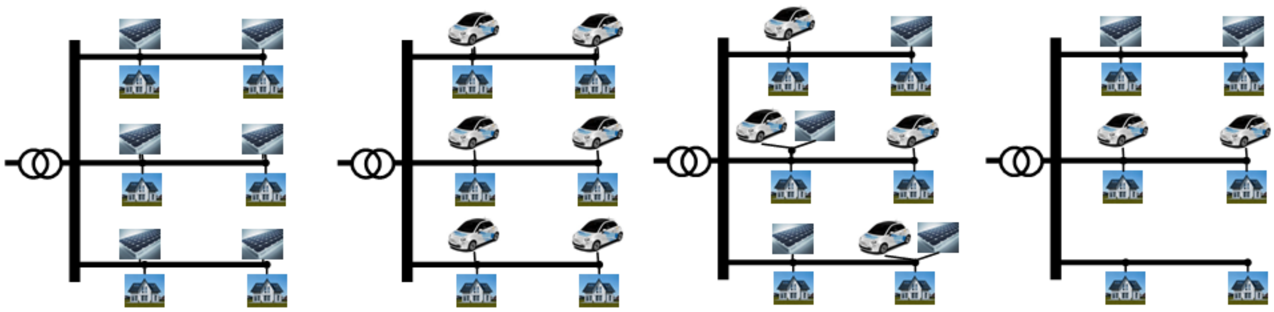


**Fig. 74A-D pv and electric vehicle placement**

**Evaluation criteria**

Although 15 minute resolution has been used for all calculations, evaluations followed DIN EN 50160 regulations, i.e. the need for voltage-control was determined by voltages above 110 % or below 90 % of nominal voltage respectively.

Throughout the simulations maximum and minimum voltages within each grid have been stored for each time instance. In order for OLTC (or other technical solutions providing one actuator for all feeders) to be an option to solve voltage problems, it is desirable to have a rise or a fall within the grid only, but not a spread. Fig. 75 demonstrates the importance, where no regulation with OLTC-based solutions is possible, but individual regulation of all feeders is required, which will be described as “**single branch controller**” in the following.

**Main results**

Three main results have been obtained by the given calculations – requirements for voltage in control in German LV distribution grids, basic guidelines for application and required design parameters.

- Requirement for voltage control

Scenario calculations as described above have been used to determine the need for voltage-controlled secondary substations. Best-case scenario results are presented in Fig. 75. As expected, the largest requirement can be foreseen for rural distribution grids, as PV installations are most common here and at the same time long feeders (often equipped with overhead lines with high resistances) are commonly found. The total demand in 2030 is expected to reach approximately 42% in rural grids, 29% in sub-urban and 10% in urban grids. Moreover, especially in rural areas, where high installation rates of PV are expected until 2020, the total demand will almost be fully reached by then (39%), leading to a need to retrofit or replace more than 1/3 of all substations within less than 10 years.

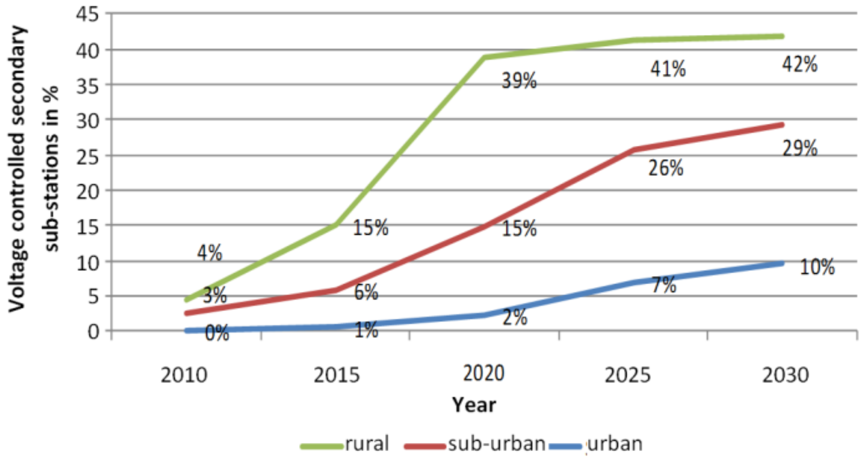



**Fig. 75 Voltage-controlled substations requires in rural, urban and sub-urban grids**

- Guidelines for application

A more detailed picture of the need for voltage control in different areas of supply is given in Fig. 76 and relates to the scenario described in Fig. 74a, where only PV was taken into account in addition to household load profiles. Voltage control is predominantly required in rural grids, especially in grids with long feeders and a rather high density of houses (type 2). 70% of these grids need voltage control, 15% of which can only be effectively realized by single branch controllers. As this type of grids makes up roughly 22% of all German LV grids, this result is even more important. Calculations as described in Fig. 73b-c have been carried out, but lead to similar results. Effects of PV on the voltage in LV levels dominate all other technologies.

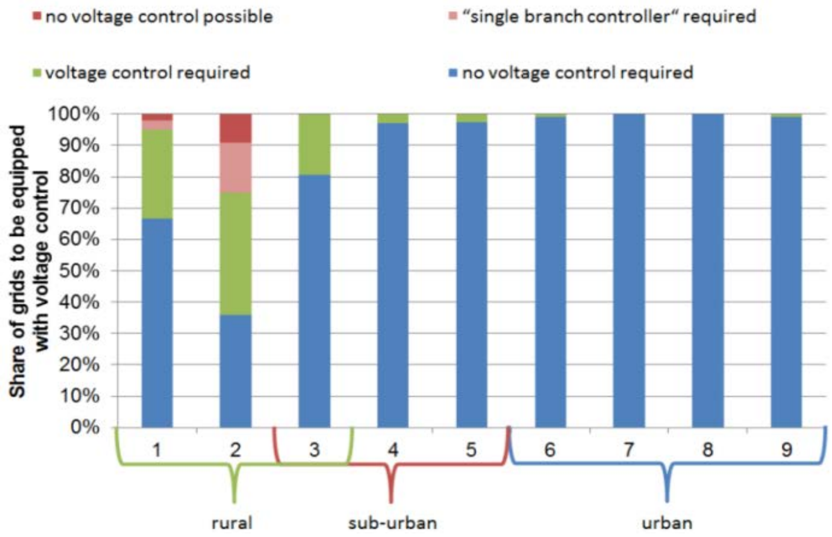



**Fig. 76 Types of voltage control in different LV grids**

- Design of voltage controllers

Finally, the maximum required regulation capabilities have been examined as basic design criteria. Again, rural grids and PV strongly dominate the results as shown in Fig. 77.

About 30% maximum regulation capability (downwards) is required in order to keep the voltage within the given limits at all times, whereas only 16% are required in grids of type 1 and only 9% are required in grids of type 2 in order to keep the voltage within the given limits in 95% of all 15 minute intervals. New control algorithms need to be developed, taking into account asymmetric regulation capabilities and asymmetric load conditions.

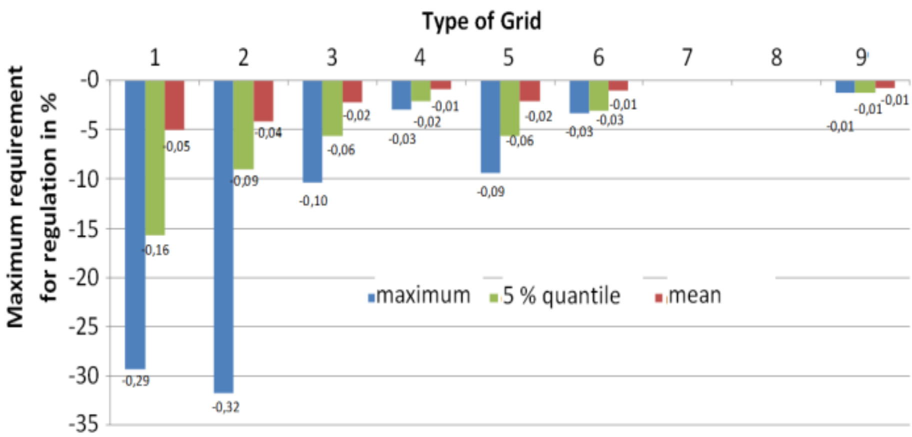



**Fig. 77 Required regulation capabilities**

**Conclusion and Outlook**

The development of a stochastic load and generation model for the assessment of voltages within LV distribution grids has been shown.

The application of this model to a variety of synthetic LV grid models has proven the need for voltage control in secondary substations especially in rural areas, where more than 1/3 of all substations have to be retrofitted until 2020. Technological development will be required in order to allow for "single branch control".

The regulation capabilities strongly vary depending on the goal to be achieved, which leads to new research question, such as the optimal combination of different technical options for voltage control (e.g. secondary substation in combination with reactive power compensation). Furthermore, optimal algorithms both for the combination of different technologies and for the application within different types of grids need be worked out.

### F.2 – 2nd Case study

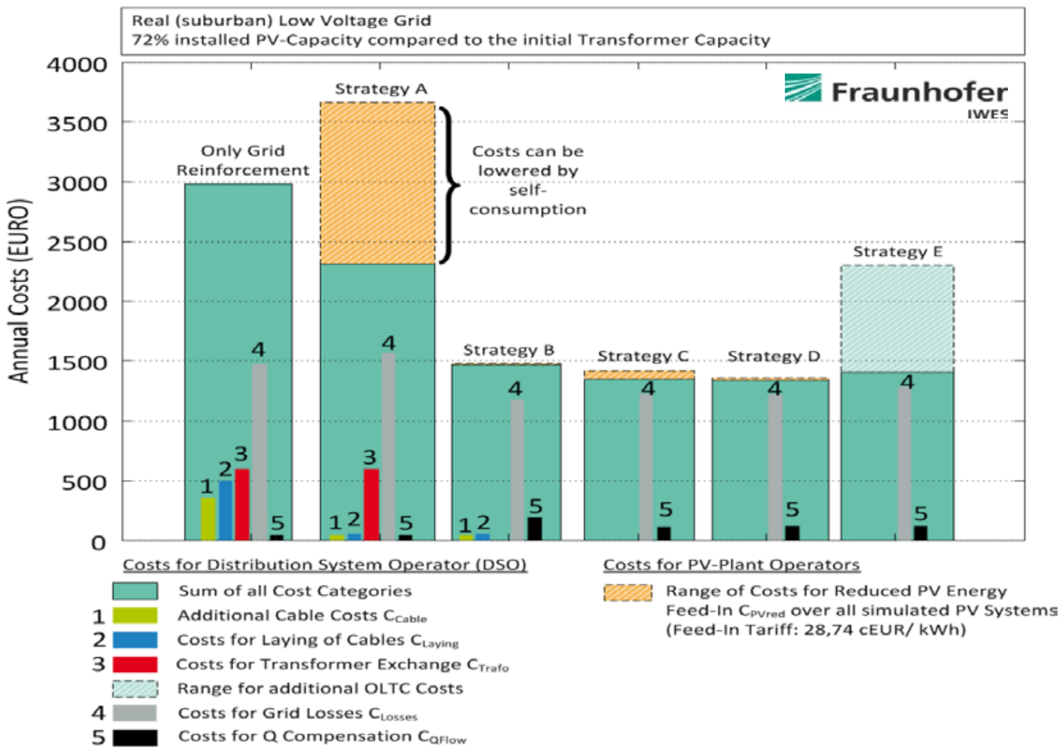
Local voltage control strategies for PV inverters are becoming increasingly important as more and more German distribution grids are highly penetrated with PV capacity. Approximately 70% of the total installed PV capacity is currently connected to low voltage grids. Therefore, the technical and economic assessment of smooth grid integration becomes a major issue. Their active and reactive power control capabilities allow PV inverters to contribute to lower their impact (voltage rise) on the grid in times of high solar irradiation. A major benefit can be to increase the hosting capacity of specific grid sections for additional generation capacity. This section presents the results of a cost-benefit analysis for different autonomous voltage control strategies in order to determine the economic impact for the PV plant operator as well as for the DSO at low voltage level [110].

Table 32 lists the investigated voltage control strategies, which were technically and economically assessed based on one-year RMS simulation in 1 minute resolution for a real LV grid section [111]

**Table 32: Description of the different control strategies** [111]

| Strategy | Description | Regulatory Framework |
|---|---|---|
| **A** | Fixed active power limitation to 70% of installed PV capacity | Required until 2013 by PV systems with an installed capacity of less than 30 kWp and no remote control capability. |
| **B** | Reactive power provision depending on active power feed-in | Can already be required from DSO according to German MV and LV guidelines. |
| **C** | Automatic voltage limitation. Active power output gets reduced in order to maintain a preset voltage threshold value | Not yet officially required. |
| **D** | Same as strategy C, only that reactive power is provided first before active power output gets reduced in addition | Not yet officially required. |
| **E** | Distribution transformer equipped with on-load tap changer | Not officially required but first commercialized products are already available on market. |

Fig. 78 shows that the extent of grid reinforcement measures can be significantly reduced by demanding additional voltage control support by PV inverters instead of just feeding-in pure active power. This lowers the necessary investment costs for increasing the hosting capacity of the investigated LV grid section compared to traditional grid reinforcement measures. Further information on this analysis can be found in [111] and [112]. Another study about increasing the hosting capacity on MV level can be found in [113].




## Annex G – Greece

### G.1 – 1st Case study

A 150/20 kV substation comprises 2x25 MVA transformers, operating with the MV bus coupler closed. The short circuit capacity at the MV busbars is then equal to 220 MVA. Given the design fault level of 250 MVA, there is a short circuit margin of 30 MVA available to all DER to be connected to the MV network of the substation. The aggregate capacities (MW) already connected to the network and their short circuit contributions are shown in Table 33[34]. Hence, the short circuit margin collectively available to new DER installations is 30 – 23 = 7 MVA.

**Table 33: Short circuit contribution of each DER technology**

| | Wind | Biomass | Small Hydro | PV |
|---|---|---|---|---|
| Aggregate capacities (MW) | 1 | 0.5 | 1.5 | 10 |
| Short circuit contribution (MVA) | 3 | 2.5 | 7.5 | 10 |

The actual residual capacity depends on the technology of DER to be connected. E.g. while 7 MW of PV plants could be accommodated, a margin of only 7/5=1.4 MW is available to biomass plants, taking into account the respective typical fault level contributions (as a very rough estimate).

### G.2 – 2nd Case study

[34] Since a variety of different wind generator technologies exist, each with a different fault contribution, the DNO adopts an average contribution of 3 times the rated capacity, as a rule of thumb for fast calculations where the exact WT type is not known (e.g. when assessing future capacities). For PVs a contribution factor of 1 is used, while for DER using rotating machines directly connected to the network (e.g. biomass, CHP, small hydro) a factor of 5 is typically applied. For more accurate calculations, proper short circuit analysis is employed.

This case study refers to a real network and was carried out by the Northern Greece (Macedonia - Thrace) Regional department of the DNO. In this network a small pv power plant with nominal power 150 kW is already connected and another one with nominal power 2.1 MW has applied for connection.

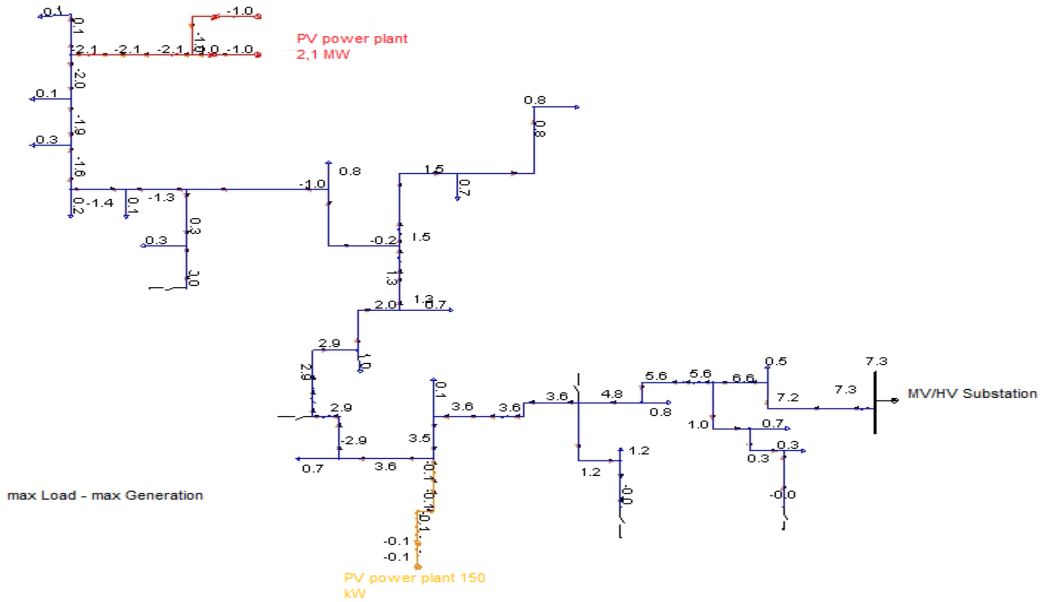



**Fig. 79 MV network used for a DER interconnection case study**

The load flow calculation shows a violation of the voltage variation limit (δU<3%) in certain nodes as the following Table 34 shows.

**Table 34: Results of voltage regulation study in four extreme cases (existing network)**

| | MAX LOAD | | MIN LOAD | | $U_{max}$ | $U_{min}$ | $U_{med}$<5% | ΔU<3% |
|---|---|---|---|---|---|---|---|---|
| NODES | Min DER [kV] | Max DER [kV] | Min DER [kV] | Max DER [kV] | [kV] | [kV] | [%] | [%] |
| P1 | 21,50 | 21,50 | 20,50 | 20,50 | 21,50 | 20,50 | 5,00% | 2,50% |
| W1 | 21,50 | 21,50 | 20,50 | 20,50 | 21,50 | 20,50 | 5,00% | 2,50% |
| W2 | 21,08 | 21,15 | 20,40 | 20,45 | 21,15 | 20,40 | 3,86% | 1,88% |
| …… | | | | | | | | …… |
| …… | | | | | | | | …… |
| E1 | 19,45 | 20,06 | 19,98 | 20,56 | 20,56 | 19,45 | 0,03% | 2,76% |
| E2 | 19,43 | 20,11 | 19,98 | 20,63 | 20,63 | 19,43 | 0,13% | 2,99% |
| E3 | 19,39 | 20,24 | 19,97 | 20,78 | 20,78 | 19,39 | 0,43% | 3,49% |
| E4 | 19,38 | 20,33 | 19,96 | 20,87 | 20,87 | 19,38 | 0,63% | 3,72% |
| E5 | 19,38 | 20,67 | 19,96 | 21,21 | 21,21 | 19,38 | 1,48% | 4,59% |
| E6 | 19,38 | 20,67 | 19,96 | 21,21 | 21,21 | 19,38 | 1,47% | 4,59% |

Reinforcing a part of the network is a possible solution, however the problem still persists. Instead of reinforcing a long section of the feeder, a more economical solution is to install switched capacitors, raising the voltage at maximum load – minimum generation conditions, thereby reducing the variation of the voltage around the mean value, which was the limiting constraint. The following figure shows the necessary works to interconnect the 2.1

MW PV plant: red color indicates the feeder extension, green color shows the reinforced part of the line and brown denotes the capacitor installation position. The new voltage profile is shown in Table 35.

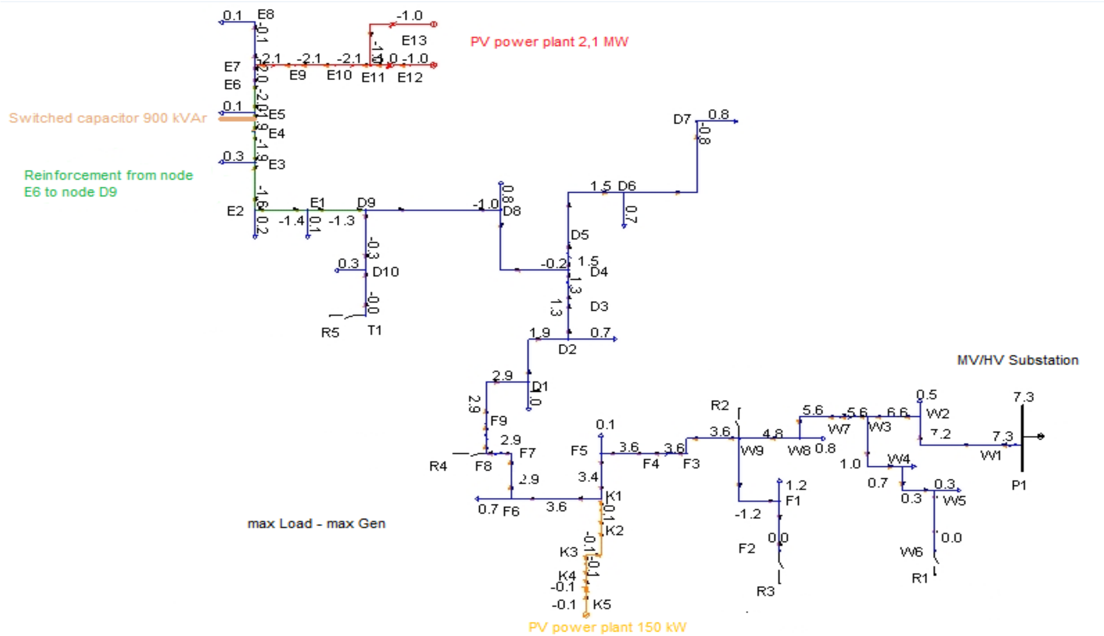



**Fig. 80 MV network used for a DER interconnection case study**

**Table 35: Results of voltage regulation study in four extreme cases (with interconnection works)**

| | MAX LOAD | | MIN LOAD | | $U_{max}$ | $U_{min}$ | $U_{med}$<5% | ΔU<3% |
|---|---|---|---|---|---|---|---|---|
| **KOMBOI** | **Min DER [kV]** | **Max DER [kV]** | **Min DER [kV]** | **Max DER [kV]** | **[kV]** | **[kV]** | **[%]** | **[%]** |
| P1 | 21,50 | 21,50 | 20,50 | 20,50 | 21,50 | 20,50 | 5,00% | 2,50% |
| W1 | 21,50 | 21,50 | 20,50 | 20,50 | 21,50 | 20,50 | 5,00% | 2,50% |
| W2 | 21,12 | 21,15 | 20,40 | 20,46 | 21,15 | 20,40 | 3,89% | 1,86% |
| W3 | 20,80 | 20,86 | 20,33 | 20,44 | 20,86 | 20,33 | 2,98% | 1,34% |
| …… | | | | | | | | …… |
| …… | | | | | | | | …… |
| E2 | 19,73 | 20,05 | 20,03 | 20,58 | 20,58 | 19,73 | 0,77% | 2,12% |
| E3 | 19,71 | 20,11 | 20,03 | 20,65 | 20,65 | 19,71 | 0,91% | 2,36% |
| E4 | 19,71 | 20,15 | 20,03 | 20,70 | 20,70 | 19,71 | 1,01% | 2,48% |
| E5 | 19,70 | 20,31 | 20,03 | 20,86 | 20,86 | 19,70 | 1,41% | 2,89% |
| E6 | 19,70 | 20,31 | 20,02 | 20,86 | 20,86 | 19,70 | 1,41% | 2,89% |

## Annex H – South Korea

The aim of this annex is to present an example for an engineering process of detailed evaluation so as to determine the maximum interconnection capacity of DER at a certain point of a feeder. For the purpose of detailed examination, a load flow study based on the following model distribution system is conducted under various conditions of DER's generation and customer's load.

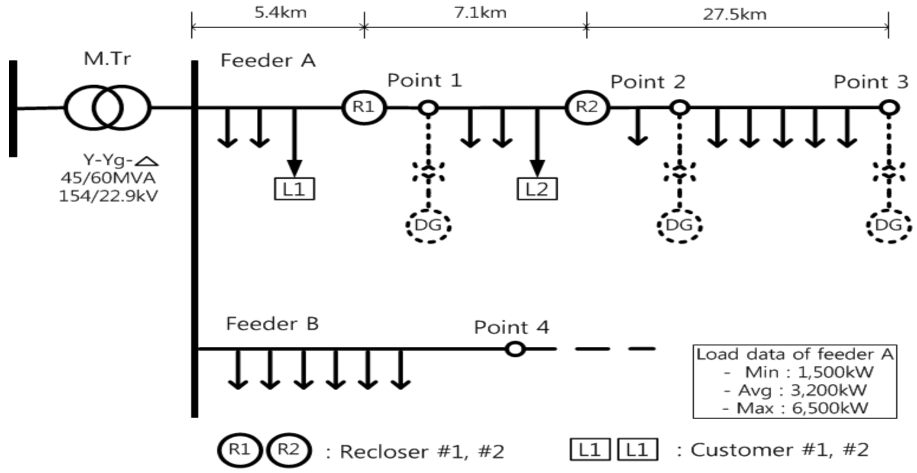
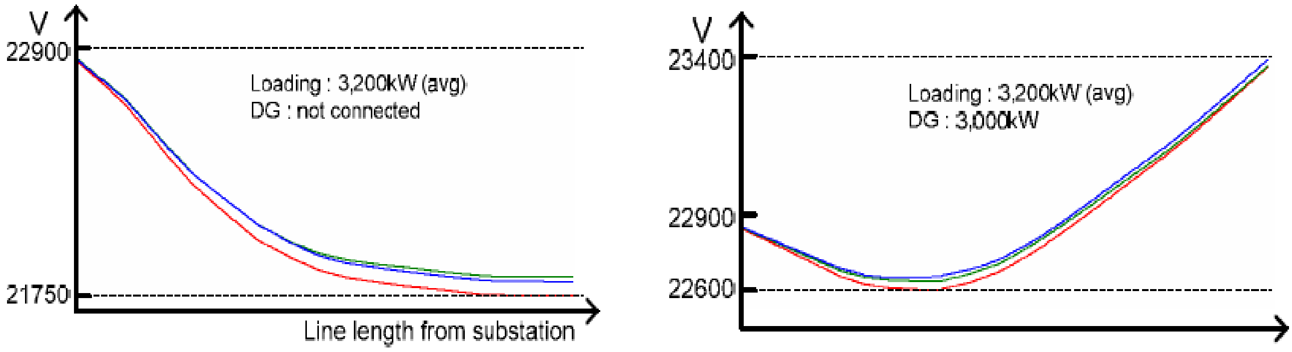



**Fig. 81 Targeted distribution system**

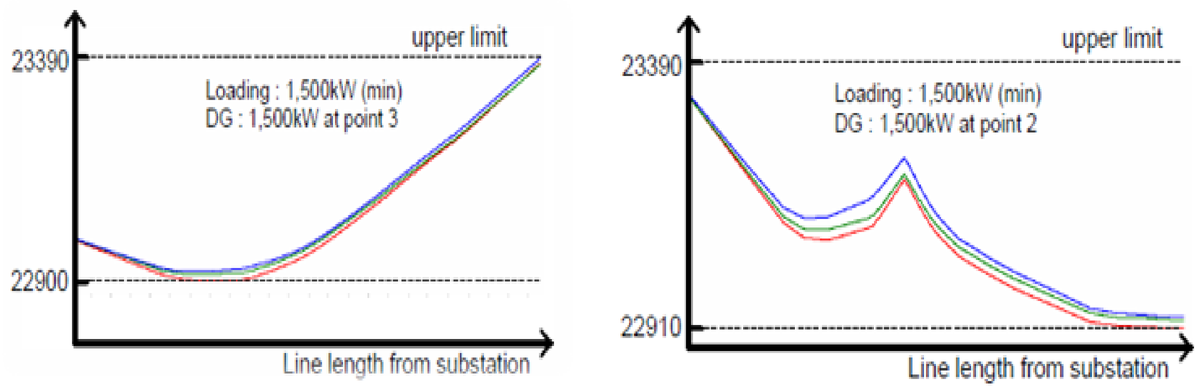
- Background
  - In the previous version of grid code in Korea, the maximum hosting capacity of the public MV feeder was 3 MW and most crucial factor for permitting interconnection was steady-state voltage variation which should be within 2% of the nominal.
  - However, the above crucial limits, 3 MW and 2%, are abolished to promote introducing more DER into grid in the recent revised version of grid code. The most crucial factor in new guide line is service voltage range which should be within 220±13 V at the all customer sides.
  - This procedure requires a lot of information such as hourly load conditions and hourly DER generations for at least one year to find out the exact light-load condition, and feeder topology and line constant for a load flow calculation with a simulation software program.
- Basic simulation for model distribution system
  - Under average load condition (3200 kW) and no generation of DER, simulation result shows a typical voltage profile of distribution feeder as shown in Fig. 81 (a).
  - According to the previous version of grid code, if we interconnect the maximum hosting capacity of DER, 3 MW, into the end of the feeder under average load condition, the voltage profile will be obtained as shown in Fig. 81 (b). It clearly shows that the voltage of PCC at the end of the feeder is higer than the sending voltage at substation busbar due to nominal output power of DER.
  - It seems like quite acceptable the 3 MW of DER capacity in the light of voltage, but in order to determine the exact maximum interconnection capacity of DER at the end of the feeder, the average-load condition should be changed to light-load condition
  - If possible, the sending voltage at substation busbar which is taken into account OLTC(On Load Tap Changer) operation should be included in the simulation calculation.




(a) No DER generation (b) 3 MW of DER generation

**Fig. 82 Average load 3000kW and DG interconnection voltage profile**

- Admissible maximum interconnection capacities of DER at different locations in the feeder
  - According to basic information about the feeder, the light-load condition is 1.5 MW. Under this load codition and the differnt locations, point 2 or point3, simulation results are obtained respectively as shown in Fig. 82 (a) and (b).
  - In this examination, the voltage level at any node should not exceed the upper limit of MV system, 23380 V (about 1.02 pu) at all circumstances. The busbar voltage of the main transformer at substation is assumed as 23023 V (about 1.005 pu) and operational factor is also assumed as 100%.
  - As a result of simulation, the maximum hosting capacity at the end of the feeder, point 3, is determined as 1.5 MW under above circustances. As shown in Fig. 83 (b), there is some upper margin for additional interconnection of DER when 1.5 MW of DER is interconnected at the middle of the feeder, point 2.




(a) 1.5 MW output at point 3 (b) 1.5 MW output at point 2

**Fig. 83 The voltage profile for 1500kW DG interconnection at point 2 (15km location from substation)**

  - Within the admissible voltage range, the simulation shows that the maximum hosting capacity at the middle of the feeder, point 2, is determined as 3.7 MW under the same conditions as shown in Fig. 83
  - This result reveals that over 3 MW of DER can be connected into the public feeder depending on location, loading condition, OLTC opertation and so on.

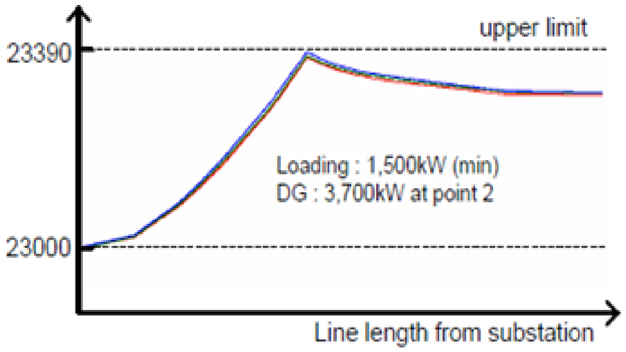



**Fig. 84 The voltage profile for 3700kW DG interconnection at point 2(15km location from substation) in the condition of minimum voltage margin**

In conclusion, the revised grid code and guideline with detailed engineering process enable KEPCO to reasonably evaluate hosting capacity of DER at any PCC in feeder in consideration of practical information about distribution system operation. In addition, there is an ongoing research project to increase hosting capacity of DER as a way of controlling reactive power of DER and determining optimal tap voltage of SVR in MV feeder. These technologies will be applied to the plant where DER cannot be connected into distribution system due to violation of interconnection guideline.